SSEN DISTRIBUTION RIIO-ED2

# LOAD-RELATED PLAN BUILD AND STRATEGY

RIIO- ED2 Business Plan Annex 10.1

Scottish & Southern Electricity Networks

# CONTENTS

# EXECUTIVE SUMMARY

## During the next decade our electricity network will undergo its most significant structural change since the formation of the National Grid.

The UK and Scottish Governments have set ambitious targets of net zero by 2050 and 2045 respectively, requiring a total transformation of the way we use electricity in our everyday lives. Our electricity distribution network is integral to enabling our local communities and wider governmental ambitions, by facilitating the decarbonisation of heat and transport, and enabling the connection of low carbon renewable generation.

In the ED2 period we expect to spend £350m on proactive load-related expenditure across our two networks; £272m in the South (SEPD) and £78m in the North (SHEPD). This is in addition to the £212m related to customer connections. This will accommodate increases in demand we have identified as highly likely and will help ensure we do not foreclose future pathways. This expenditure will release an additional 2,333MVA of network capacity across our two network areas. Our expenditure also includes the procurement of flexibility services which enable us to better use existing capacity as an alternative to conventional constructed solutions.

In order to further protect customer bills from risk of uncertainty, we propose that not all of this expected expenditure should be funded 'up-front' through our baseline allowance; with £52m of this £350m being funded *within* the ED2 period through an uncertainty mechanism. This separate funding includes expenditure on our high-voltage (HV) and low-voltage (LV) system for the last three years of the ED2 period and will allow for better investment decision-making with higher levels of certainty for our customers. Our ED2 ex-ante baseline expenditure proposal is therefore £298m (£227m in SEPD and £71m in SHEPD).

Our Strategic Vision for meeting net zero ensures that we can meet network requirements post-2030 whilst protecting consumers against inefficient expenditure.

We have followed a well-defined and robust process to develop our load-related investment plan, consistent with the approach outlined by Ofgem for use across all network companies. We have selected the distribution future energy scenario (DFES) Consumer Transformation as the scenario underpinning our baseline plan. This is consistent with the feedback received through our stakeholder testing to assess local ambition and need. We have studied network conditions across all scenarios in ED2 to identify when and where network capacity constraints will occur. In each case we have considered a range of options to manage the anticipated constraint and ensure compliance with relevant industry security planning standards and related regulations.

In proposing solutions we will meet the needs of our customers – both today and the future – including appropriate consideration of asset health and network reliability. In developing our expenditure plan we have used cost-benefit analysis (CBA) to select the most economic and efficient options for managing network constraints. This refinement process has enabled a cost reduction of around 43%, relative to our initial 'first-pass' bottom-up expenditure plan. We have 'stress-tested' our proposals with comprehensive sensitivity testing. This includes testing the impact of variation in peak demand and changes to the assumed cost of flexibility. From this analysis we have concluded that our proposed expenditure is robust, economic, and efficient for consumers.

We know that assumptions can change quickly, as a result of policy updates, market conditions and technological advances. Our scenario analysis estimates further expenditure of up approximately £188m could be required in ED2 across our networks. Having an agile and adaptive regulatory framework which is versatile to external changes is, therefore, vital.

We have been working directly with Ofgem and other stakeholders over the course of the last 18 months to consider the need-case and principles of operation for new forms of Uncertainty Mechanism (UM), applicable to all DNOs. We propose Ofgem should pursue an automatic (volume driver) UM for load related expenditure. The detailed design of a volume driver is currently being developed through cross-industry cooperation and we propose a detailed mechanism in this Business Plan.

# 1 ENHANCED ENGAGEMENT


Our Load strategy has been informed by our Enhanced Engagement programme, full details of which are set out in Annex A 3.1. Our draft plan was underpinned by three phases of stakeholder and customer engagement (illustrated in the diagram above). The details of this engagement and insights are set out in Appendix B to this Annex and provide a clear line of sight between what stakeholders told us and our Load strategy and outputs.

## 1.1 FINAL LOAD STRATEGY TESTING AND ACCEPTANCE

We have refined our final Load strategy and outputs based on Phase 4 of our Enhanced Engagement, which involved direct testing of the strategy, outputs and costs with 1,895 stakeholders through 15 events. The table below sets out the clear line of sight of the changes between our draft and final Load strategy and outputs based on this engagement.

## 1.2 ENGAGEMENT EVIDENCE TRIANGULATION AND CHANGES BETWEEN DRAFT AND FINAL PLAN

The table below summarises the clear line of sight between stakeholder and consumer insights and our Load strategy and outputs. For our **draft Load strategy** and outputs, based on phases 1 to 3 of our enhanced engagement program, we demonstrated how engagement insights had informed our outputs using these keys:

Findings converge to support proposals.

Findings generate new insights that lead to further refinement of proposal.

The proposed approach diverges from the findings.

To demonstrate the line of sight between the scope of **change between draft and final**, based on testing our draft proposals with stakeholders and consumers, we use theses keys:

| Strategy/Output | Phases 1-3 Enhanced Engagement | Phase 4 Outputs and Cost Testing | Acceptability |
|---|---|---|---|
| **LV**<br><br>LV monitoring and smart meters is providing data to help us understand how our network is configured, how it performs, and improving our visibility to enable us to better correlate local generation with customer demand. | **Stakeholders said**<br>A minority of stakeholders highlighted that some solutions did not fit well with our iHost interface, which discouraged some from tendering to supply LV monitoring equipment, but most stated that it did not present a problem for their solution.<br>**Our response**<br>Although iHost is an issue to some, we will continue to use this interface, which is a proprietary system used throughout the industry, because a substantial majority of suppliers found it fit for purpose. We believe it is central to creating a supplier-agnostic approach, and are working with stakeholders to create enhancements that will deliver this as BAU. | **Stakeholders said**<br>Advances in LV network monitoring and analysing data coming from the monitiring are key to managing uncertainty in forecasting demand and faciltiing net zero ambitions.<br>**Our response**<br>Our strategy acknolwedges that forecast assumptions can change quickly and proposed an Uncertainty Mechanism to address this uncertainty. In developing the detailed design of the uncertainty mechanism we will take into consideration LV monitoring data. | 79% for *Accelerated progress towards a net zero world* strategic outcome |

| Strategy/Output | Phases 1-3 Enhanced Engagement | Phase 4 Outputs and Cost Testing | Acceptability |
|---|---|---|---|
| **REFINED**<br>**Output:** Ready the network for net zero, consistent with up to 1.3m Electric Vehicles and up to 800,000 heat pumps connecting by 2028 | **Stakeholders said**<br>Most LA stakeholders did not have sufficiently developed plans themselves to be able to select a DFES<br>**Our response**<br>We have selected Consumer Transformation as the baseline scenario for ED2. Our funding proposal is based on Consumer Transformation only for the first two years of ED2 because of uncertainty, and so we are ready to respond to a range of potential pathways. | **Stakeholders said**<br>Most stakeholders including the Local Authority segment acknolwedged the uncertainty around demand forecasts and supported the proposed Uncertainty Mechanism. They also urged proactive approach to engagement to build a more integrated local energy system.<br>**Our response**<br>We will continue to work with industry stakeholders on a detailed design mechanism to implement the proposed Uncertainty Mechanism. We have proposed a specific CVP to provide additional support and resources above BAU to engage with Local Authorities and communities on local area energy plans. | 76% |
| **NEW**<br>**Output:** Ready the network for net zero, consistent with a total of 8GW of distributed energy resource (including windfarms, solar, and energy storage) connecting by 2028 | - | **Stakeholders said**<br>Proposed targets for facilitating net zero on our network should include the supply side in addition to targets on EVs and heat pump.<br>**Our response**<br>We added a specific output that captures our network plans for facilitating distributed energy resources. | 83% |

# 2 INTRODUCTION

One of the critical functions of an electricity network is the ability to evolve to meet changing customer and consumer requirements; these usually manifest as network constraints due to changes to the supply and demand connected to our networks.

We refer to this as load-related expenditure. SSEN is well experienced in managing these changes and considering the resultant solutions for our 3.8m customers. SSEN has worked to find innovative ways to manage these constraints. In ED1 we have released approximately 657MVA of network capacity – equivalent to the capacity needed to power over 300,000 homes.

As we transition from ED1 to ED2 our sector will go through a pivotal change. The UK Government target to reduce carbon emissions to net zero by 2050 is now in law; and in Scotland this target is the earlier date of 2045. These legally binding targets are reinforced by interim targets such as the ban on sales of new petrol and diesel cars by 2030 in England and 2032 in Scotland. Across our two networks 87% of local authorities have declared Climate Emergencies, with some setting net zero ambitions between 2025 and 2030. Our stakeholders are increasingly demanding rapid change, and we need to play our part.

We firmly believe that DNOs have a central role to play in the delivery of net zero, and that this must be reflected in the ED2 framework. However, the change is already underway. In just 10 months between January and October 2020 the UK witnessed a 129% increase in passenger EV sales, and a 35% decline in sales of internal combustion engine vehicles[1]. The 6th Carbon Budget announced in December 2020 signifies the importance of the next 15 years whereby 60% of the emissions reduction needs to be realized if we are to meet our targets as a country.

DNO load-related expenditure is integral to decarbonisation of heat and transport, and to the connection of low carbon renewable generation. Our DFES scenario range suggests national peak demand could increase by 6.8GW (Consumer Transformation) in ED2; with approximately 1.3 million electric vehicles (EVs), 800,000 heat pumps, and with the potential for 8GW of distributed energy resource (including windfarms, solar, and energy storage) connecting to our networks by 2028. In order to successfully deliver this and the longer-term net zero legislative targets we must actively balance the interests of current and future consumers, recognizing that investment today will help keep bills low in the future, delivering wider societal benefits and resulting in lower costs to consumers overall. DNOs must be able to facilitate growth in a timely and efficient manner whilst also minimizing disruption.

In this Annex we summarize our proposals and describe our approach to load-related expenditure decision-making. We highlight the key insights pertinent to understanding our proposal rationale and explain why we have set our proposals over alternatives; including what needs to be believed for our proposals to change. We explain the actions we will take to deliver these proposals and how we have concluded these are the most economic and efficient choices co-created with stakeholder expectations.

Finally, we know the future world we operate in could be different to the one on which we build our plan, so we also discuss where, and why, this could be the case and what we propose to do about it; including how we can retain optionality and ensure long-term consumer value.

[1] Bloomberg New Energy Finance Executive Factbook 2021.

# 3 SETTING THIS ANNEX INTO THE CONTEXT OF OUR PLAN

In this annex we articulate the detail of our load-related investment proposals for our two licence area networks, SHEPD (North) and SEPD (South). These proposals complement the higher-level summary of our strategy in ***Our Network as a net zero Enabler (Chapter 10)*** of our business plan submission, within the Business Plan Section: Smart, Flexible & net zero Energy System.

Load-related expenditure is required to resolve capacity restraints on our network. Our primary driver for load related expenditure is changing customer requirements, such as the volume and location of generation and demand connected to our network. In Section 6.2[2] of this annex, and in ***Our Forecasting and Future Energy Scenarios (Chapter 9)*** of our Business Plan, we provide more substantive detail on these drivers. Load related expenditure also includes replacement of equipment in cases where the fault level capability is no longer adequate, as a result of changes in demand and generation, or when we need to upgrade the capacity of our connections to the transmission network.

This annex should be read in conjunction with tables CV1-CV4 in the Business Plan Data Tables (BPDT) which provide costs and volumes on load related expenditure[3.] Connections-related reinforcement expenditure is set out in BPDT C2.

Additionally, this Annex is supported by detailed Engineering Justification Papers (EJPs) and Cost Benefit Analysis (CBA) documents which are included in our submission. These provide detailed justification for individual investments which make up the costs and volumes in our plan.

Unless otherwise stated, the numbers presented in this annex are for both of our licence network areas (SSEN total). The EJPs and CBAs provide a detailed breakdown for each of our licence areas for key tables and charts.

## Creating the load-related plan holistically as part of the wider proposals

By leveraging our DSO capabilities, and exploring Whole Systems solutions, we will find new ways of delivering for customers. Our load-related investment plan will also help avoid 6,659 $tCO_2e$ through losses reduction (as further detailed in our Environmental Action Plan, Annex 13.1). Our IT investment will underpin flexibility solutions and enable us to meet changing customer expectations (see Chapter 5).

We have embedded over £11m of efficiencies in our load plan through our reduced unit rates (see our Cost Efficiency, Chapter 15 for further details), in addition to over £5m of savings through our optimisation across different investment drivers, as well as creating 1,180MVA of additional capacity through our resilience activities.

Load-related expenditure is an important component of the overall plan and is linked to many other areas of expenditure and strategies throughout the suite of documents.

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2 Also in Appendix E to this Annex.

3 Tab 'LI Substations' which related to primary network utilization; and to table M20 for supplementary information.

**DSO Strategy (*Annex 11.1*)**

Our DSO strategy enables a key set of potential solutions to load-related requirements; foremost among these is flexibility. On our lower voltage networks, our load-related expenditure proposals take full account of a range of different sources of flexibility, including domestic smart EV charging, domestic vehicle-to-grid; flexible heat from domestic heat pumps; the expected uptake in time-of-use tariffs, and a variety of energy efficiency interventions. A full and detailed account of our methodology for assessing the benefits of flexibility at HV and LV is provided in our DSO Annex.

**Whole Systems *(Annex 12.1)***

A key part of our load-related plan is consideration of alternative ways to resolve load-related network constraints. Whole systems solutions can offer opportunities to resolve load issues, as well as delivering further benefits to consumers. We will continue to work with transmission companies, but also seek opportunities across energy vectors to find high-impact ways of resolving load-related constraints on our network.

**Strategic Investment Uncertainty Mechanism (*Appendix to Uncertainty Mechanisms, Annex 17.1*)**

The Strategic Investment UM sets out how we will continually update our best view of the network requirements – both short-term and long-term – and how we will use the UM to address these efficiently for consumers where additional funding, over and above the ex-ante baseline allowances, may be required. We anticipate significant use of such a UM – both to fund high probability investment volumes in HV and LV network in the latter years of ED2 (years 3-5), and also to provide additional expenditure required if the energy system continues to follow one of the higher demand net zero scenarios.

**Network Visibility Strategy (*DSO Strategy, Annex 11.1, Appendix H*)**

The Network Visibility Strategy sets out our pathway to 100% visibility of power flows (on all asset levels of our network) through the installation of LV monitoring on almost one fifth (19%) of our secondary ground-mounted substations, from direct embedded measurement on selected plant, and through the further development of advanced data-led modelling and analytics. Enhanced network visibility allows us to plan with more certainty, to manage our assets more effectively and to provide the data necessary to facilitate markets and allow the optimal use of the network. Through this strategy we are able to detect network overloads more precisely and deploy flexibility solutions more effectively. Our Network Visibility Strategy also forms a core part of our proposed strategic investment UM; as visibility will reduce uncertainty and allow for more robust use of the mechanism.

**Non-Load expenditure (*Safe & Resilient, Annex 7.1*)** and **Environment (*Environmental Action Plan, Annex 13.1*)**

Both non-load expenditure and environmental requirements drive significant work on some of the same assets proposed in the load-related expenditure plan. By careful alignment, coordination and cross-checking between the plans we have ensured there is no duplication of effort nor inefficiency in delivering these different sets of requirements on the same assets. Our ongoing investment planning and decision-making processes will deliver the expenditure, at the right time for the right reason.

**Connections Strategy *(Annex 10.2)***

New connection activity has a direct impact on demand requirements for our networks at all voltage levels. This, in turn, drives load-related expenditure. Our plan differentiates between reinforcement works solely for connecting individual customers, and the more general load-related investment needed to ensure that the common distribution network is able to support general growth in new connections at lower levels in the network. In developing this load-related investment plan, the new connections pipeline has formed a key component of our forward view of network capacity requirements.

**Access SCR *(Appendix to Connections Strategy, Annex 10.2)***

Ofgem launched the Access SCR in December 2018 to ensure that the arrangements for network access and charging is fit for purpose and capable of delivering the potential savings of a more dynamic and flexible distribution system. This appendix summarises an overview of Ofgem's 'minded-to' position on this topic; details our approach to assessing the potential impact of the changes, and sets out our approach for our ED2 business plan. This has influenced our view of how load expenditure may evolve, and the range of expenditure that could arise as a result of the anticipated policy change on connections and access.

**Scottish Islands Strategy *(Annex 8.1)***

Our strategy for the Scottish Islands has been developed alongside our load-related investment plan for SHEPD. This includes strategic upgrades to subsea cables as critical components of our proposed Whole Systems approach during ED2.

### Load related expenditure reporting classification

There are four types of load-related investment expenditure on which DNOs are required to report through the Business Plan Data Tables (BPDT):

1. Primary network reinforcements
2. Secondary network reinforcements
3. Fault level reinforcements
4. New transmission capacity charges

**Primary network reinforcement** – are activities undertaken to resolve capacity constraints on the on the Primary (Extra High Voltage) Network (33kV and above). This category includes investment on circuits needed to provide security of supply through redundancy (n-1 and n-2). Reporting in this category requires separate identification of conventional substation and circuit solutions; innovative solutions; and flexibility services solutions. In all cases there is a requirement to report costs and capacity (MVA) released.

**Secondary network reinforcement** – are activities undertaken to resolve capacity constraints on the Secondary Network (Low Voltage (LV) and High Voltage (HV)). The reporting differentiates between reinforcement undertaken on pole mounted from that on ground mounted substations; and between conventional; innovative and flexibility services solutions. In all cases there is a requirement to report costs and capacity (MVA) released.

**Fault level reinforcement** – are activities undertaken to replace equipment when the rated fault level is no longer adequate. Reporting includes the number of fault-level constraints resolved by asset class (switchboard, circuit or other). Furthermore, the reporting must be disaggregated by voltage level and type of solution: conventional or innovative.

**New Transmission Capacity Charges** – are activities undertaken to increased the capacity at existing transmission connection points, or for new transmission connection points. The reporting requirements include expenditure information relating to the charges payable by the DNO to a transmission licensee for projects which have been initiated by the DNO but carried out by the transmission licensee. Reporting must separately identify costs associated with the reinforcement of existing transmission connection points, and expenditure required for new transmission connection points.

These four Load Related Expenditure (LRE) reporting categories do not include costs associated with High Value Projects.

# 4 WHAT WILL CONSUMERS GET FROM OUR PROPOSALS?

Our overarching strategy for ED2 is firmly centred on our core purpose: 'We power our communities to thrive today and create a net-zero tomorrow'. We are focused on creating a strong foundation to meet new demands and making a net zero world a reality for our customers and communities. Our plan is co-created with our stakeholders and customers, to deliver a local and inclusive transition to net zero. Across our plan we will do this by providing the following.

- A safe, resilient and responsive network
- A valued and trusted service for our customers and communities
- An accelerated progress towards a net zero world
- A positive impact on society

On load-related expenditure our aim is to ensure that enough network capacity is available to actively support our local communities in contributing to the achievement of net zero. We want to ensure that we are never a barrier, nor perceived to be a barrier, for the timely connection and efficient use of LCT, such as electric vehicles (EV) and heat pumps. Furthermore, it's of the utmost importance that the level of service and reliability received by our existing customers is not compromised or adversely impacted by the uptake in LCT. Table 1 provides details of our key load-related outputs.

Table 1- Regulatory outputs summary

| Output | Output type | RIIO-ED2 target | Cost in baseline plan | Consumer benefits |
|---|---|---|---|---|
| Enabling the connection of Low Carbon Technology (LCT) – demand | SSEN goal | Ready the network for net zero, consistent with up to 1.3m Electric Vehicles and up to 800,000 heat pumps connecting by 2028 | £510.2m<br><br>Baseline load and connections-driven reinforcements with additional uncertainty mechanism funding in period[4] | £110m carbon benefits and £120m customer financial benefits over RIIO-ED2, enabled by ensuring LCT customers are able to connect on time. |
| Enabling the connection of Low Carbon Technology (LCT) - generation | SSEN goal | Ready the network for net zero, consistent with a total of 8GW of distributed energy resource (including windfarms, solar, and energy storage) connecting by 2028 | | Additional revenue enabled to Distributed Generation Customers.<br><br>Carbon benefits from reduced renewables curtailment. |

[4] This forms part of our ex-ante baseline funding request and includes £212m of connections-related reinforcement in Business Plan Data Table C2. UM funding is expected to be required for delivery of the outputs.

Alongside this core LCT output, the work we undertake during ED2 is critical to enabling our best view of the world in 2030. These summary forecasts highlight the significant new loads we need to facilitate not just within ED2, but in the years shortly after – highlighting the likely requirement for anticipatory investment. These are shown in Table 2. We have not asked for significant ex-ante baseline funding to address this, as the timing of the requirement is still uncertain; however, our proposals for the Strategic Investment Uncertainty Mechanism do consider this carefully.

Table 2- 2030 views

| Load/Penetration | Best view of 2030 (Consumer Transformation 2020) value |
|---|---|
| Total electricity demand (TWh) | 44.6 |
| Total demand from HPs (TWh) | 5.0 |
| Total demand from EVs (TWh) | 4.6 |
| Peak Demand (GW) | 12.4 |
| Penetration of Electric vehicles (millions) | 1.9 |
| Penetration of Heat pumps (millions) | 1.1 |

## 4.1 OUR STRATEGIC VISION FOR MEETING NET ZERO

Our strategic vision aims to strike an appropriate balance between facilitating and supporting net zero – particularly ensuring that we are not a barrier to the uptake of low carbon technology such as EVs and heat pumps – and protecting customers against the potential cost of forecasting uncertainty and the associated risk of stranded investment in network capacity. This trade-off is shown in Figure 1.

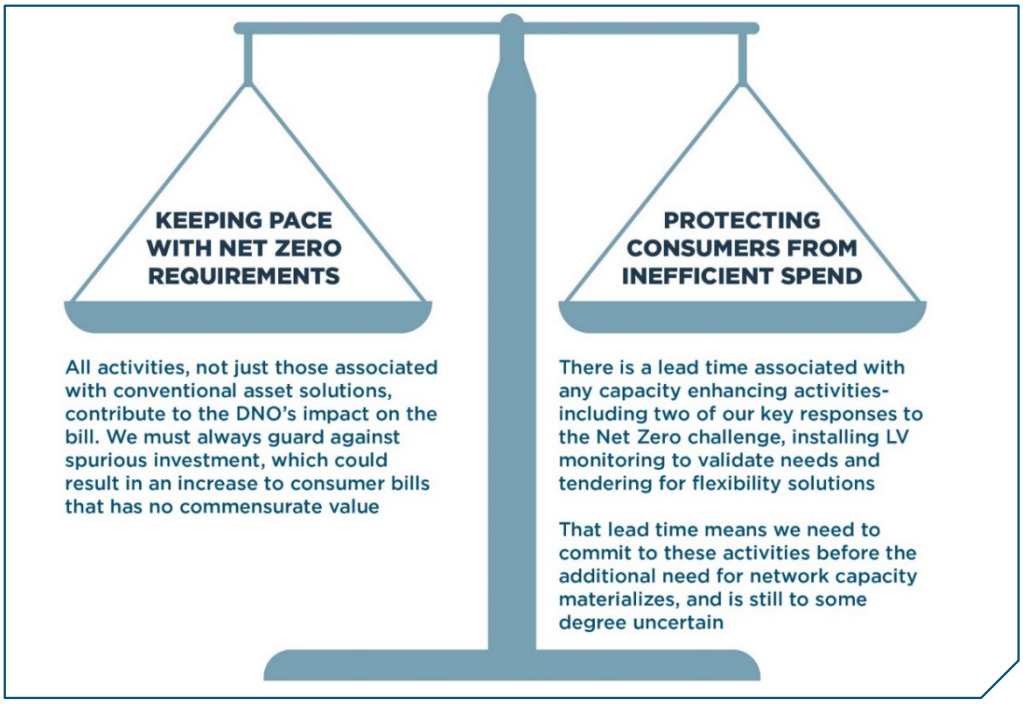


Figure 1- the key trade off in load related spend

This balance of risks and costs will be managed through the setting of an appropriate ex-ante baseline funding request, combined with the use of an appropriately designed strategic investment uncertainty mechanism.

We have calibrated both of these proposals to ensure that we can meet network requirements post-2030 whilst protecting consumers against inefficient expenditure. This is achieved in four ways:

- Understanding the peak demand and network capacity needs post ED2
- Ensuring all future net zero pathways remain open
- Sizing the capacity of new network assets in ED2 to account for post-2030 net zero alternative pathways
- Committing to annual review of evolving net zero requirments and the need for UM funding

### Understanding peak demand and network capacity post ED2

Our view of network-wide peak demand for all credible net zero scenarios post 2030 shows that capacity interventions in the ED2 period are at a very low risk of being stranded for the foreseeable future, with LCT uptake under all credible scenarios expected to deliver the demand levels currently anticipated in the network planning time horizon. If we are to ensure that future pathways are not foreclosed and distribution network is a facilitator for, and not an obstacle to, the delivery of net zero – then it is both prudent and efficient for us to plan and invest now for this projected outcome. This is described in more detail in Section 6.4.8.

### Ensuring all future net zero pathways remain open

Section 6.5 of this Annex 'Efficiently funding the plan' describes how we have calibrated our baseline request to provide for investments where we have a high degree of certainty – both in volume and location. For example, we have only included EHV projects in the last three years which appear in all net zero compliant DFES scenarios. Alongside this, we have identified a level of additional expenditure in the first two years which ensures high LCT uptake scenarios remain deliverable should they outturn – in other words, ensuring that all credible future pathways remain open.

#### *Our approach to expenditure on our lower voltage networks (HV and LV)*

Whilst our proposed ex-ante baseline expenditure includes provision for all EHV investments where we have a high certainty of need, we have taken a different approach to our HV and LV investment. This aims to further protect customer bills from risk of uncertainty, whilst ensuring that we do not hamper or otherwise impeded the anticipated uptake of LCT technologies, such as EVs and heat pumps.

In order to protect our customers against the costs of forecasting uncertainty, our ex-ante baseline funding only includes HV and LV load related investment required in the first two years in the RIIO-ED2 period. Unlike for EHV, even where HV and LV expenditure is identified as being required by all net zero-compliant scenarios in the last three years of ED2 (and whose *volume* is therefore highly certain), we have not included this in our ex-ante baseline funding request. Instead, we propose that HV and LV investment in the last three years of ED2 will be funded via an appropriately designed, agreed, and implemented uncertainty mechanism (UM).

There are two main reasons why we believe that this approach is appropriate for HV and LV investment. Firstly, whilst we have a high degree of confidence in the *volume* of reinforcement required at HV and LV, the precise *location* of investments is less certain. This is not the case for major EHV investments. Secondly, the delivery lead-time needed for planning, design and construction for HV and LV investments is typically much shorter than for EHV. This means that we can more easily adjust our investment portfolio within the ED2 period to ensure capacity related reinforcement happens at the right time and in the right place on our HV and LV network – thereby maximising the protection for customers against forecasting uncertainty.

Because we still have a high degree of certainty over the *minimum* volume of investments at HV and LV, the associated EJP[5]s provide justification for this minimum expenditure level, even though it is not all included in our ex-ante baseline proposal. The minimum expenditure level in the EJPs is based on the hybrid DFES scenario, as used for EHV. Funding the last three years of HV and LV expenditure *within* the ED2 period via an appropriate uncertainty mechanism will allow for better investment decision-making with higher levels of certainty.

This approach will enable us to support and facilitate net zero, whilst appropriately managing risk and protecting customer bills.

Our ex-ante baseline proposal does include HV and LV expenditure for the first two years of ED2, and this is based on our stakeholder-supported view of LCT-uptake and our view of the most credible net zero ED2 pathway. This is an important provision for HV and LV (and also EHV) as it aims to ensure that future net zero pathways are not foreclosed. This provides a degree of 'futureproofing' to ensure that the foundations are in place to enable our business to be able to respond efficiently to any credible future demand increases in the ED2 period and beyond.

In ***Chapter 17 Uncertainty Mechamisms*** we discuss our approach to funding the additional allowances through uncertainty mechanism (UM). Our strategic investment proposal is set out in the UM Annex[6].

More details on efficiently funding the plan can be found in Section 6.5 of this Annex.

### Sizing the capacity of new network assets in ED2 to account for post-2030

For the conventional solution options we have taken full account of the range of credible post 2030 net zero pathways, and the associated capacity requirements, when selecting the size and rating of asset replacements or additions. This is described further in Section 6.3.6.

### Committing to annual review of evolving net zero requirements and the need for UM funding

Understaking frequent and regular reviews of future network needs, and updating our forward view of network capacity requirements, is an important part of minimising the customer risk of stranded assets, whilst maximising the support for net zero. The importance of the planning process in the design and implementation of strategic investment UM is described further in Section 8.

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5 There are three EJPs to which this applies: 'HV circuits', 'LV circuits' and 'HV/LV transformers. The split between 'ex-ante baseline' funding and 'uncertainty mechanism' funding is made clear in the EJPs.

6 Annex 17.1 Uncertaintiy Machanisms .

*The importance of delivery lead times in invesment decision-making*

A key characteristic of our strategic approach is that investment is only triggered when delivery lead times make commencement of the work critical to delivering a solution at the time needed; or when advancing the work can realise an efficiency gain, or avoid the added cost of a delivery constraint. Figure 2 shows the importance of project delivery lead times in the context of addressing network needs, this is also detailed within our Deliverability Strategy Annex, 16.1.

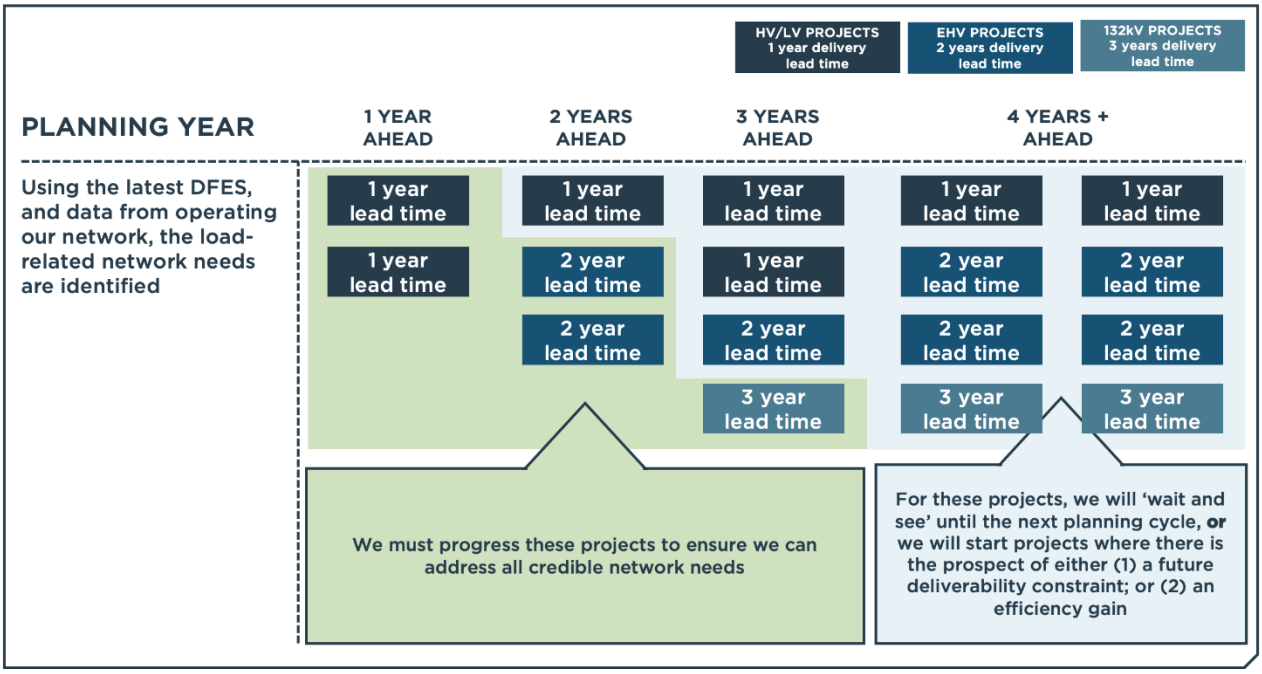


Figure 2 – the relationship between delivery lead times and investment decision-making

We anticipate load-related expenditure of £349.9m in the ED2 period on proactive load related investments across our two networks, as presented in Table 3. This is summarised by expenditure type aligned with Ofgem's reporting classification[7]. Of this £349.9m total, £297.9m is included in our ex-ante baseline expenditure, and £51.8m is expected to be funding via the strategic investment UM[8]. This provides for expenditure which we identify as being highly certain and includes the expenditure proposed to ensure that future pathways are not foreclosed.

Table 3 shows our minimum expected total load-related expenditure. It should be noted that we anticipate the potential for further expenditure in the ED2 period of around £240m linked to our most aggressive (but credible) planning scenarios, Leading the Way and Consumer Transformation. This additional amount is not included in Table 3.

7 A detailed breakdown of this allowance is provided in Appendix F.

8 The UM expenditure set out here is that required to meet our minimum requirement. Further UM funding is expected to be needed to meet demand requirements in ED2, particularly in years 3-5 where ex-ante baseline provision is low (zero in the case of HV and LV).

Table 3: Summary of SSEN's anticipated load-related investment in the ED2 period

| Type | CV table | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (£m) |
|---|---|---|---|---|---|---|---|
| Primary | CV1* | £50.8 | £20.1 | £62.1 | £51.4 | £24.7 | £209.1 |
| Secondary | CV2 | £12.6 | £13.6 | £15.6 | £15.0 | £9.2 | £66.0 |
| Fault Level | CV3 | £12.7 | £15.2 | £16.5 | £3.8 | £3.4 | £51.6 |
| NTCC | CV4 | £2.6 | £4.0 | £5.0 | £5.7 | £5.9 | £23.2 |
| TOTAL | | £78.7 | £52.9 | £99.2 | £75.9 | £43.2 | £349.9 |

In Table 4 we summarize the load-related ex-ante baseline proposal across the ED2 period[9].

Table 4: summary of SSEN's load-related investment **ex-ante baseline** funding proposal in the ED2 period.

| Type | CV table | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (£m) |
|---|---|---|---|---|---|---|---|
| Primary | CV1* | £50.8 | £20.1 | £62.1 | £51.4 | £24.7 | £209.1 |
| Secondary | CV2 | £12.6 | £13.6 | £0 | £0 | £0 | £26.2 |
| Fault Level | CV3 | £12.7 | £15.2 | £11.7 | £0 | £0 | £39.6 |
| NTCC | CV4 | £2.6 | £4.0 | £5.0 | £5.7 | £5.9 | £23.2 |
| TOTAL | | £78.7 | £52.9 | £78.8 | £57.1 | £30.6 | £297.9 |

** Includes £54.2m for Fleet-Bramley scheme reported in CV25 high-value project BPDT.*

## 4.2 PRIMARY AND SECONDARY REINFORCEMENTS

Our 'best view' expenditure on primary and secondary reinforcements will enable 2,333 MVA of network capacity released. This will be achieved through a combination of conventional (constructed) asset solutions, innovative solutions and flexibility services. This 'capacity released' will be enough to enable the connection to our network of over a million EVs and heat-pumps in the ED2 period. This will be key in enabling the achievement of our strategic ambition to facilitate the connection of 1.3m EVs,800,000 heat-pumps and 8GW of generation by the end of ED2. Table 5 summarizes the total capacity released on our primary and secondary networks; and Table 6 summarizes the total number of LCT, by type, which are enabled by our proposal, along with the associated connected LCT MW across all voltage levels for both our networks[10]. Figure 3 shows the anticipated growth in the number of heat pumps and electric vehicles in our licence areas over the ED2 period.

9 The ex-ante baseline expenditure presented in Table 4 aligns with the Business Plan Data Tables (CV1-CV4).

10 Data in table 3 is summarised from table M20 in the business plan data tables.

Table 5: summary of SSEN's capacity release in the ED2 period by reporting category (MVA)

| Type | CV table | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (MVA) |
|---|---|---|---|---|---|---|---|
| Primary | CV1* | 396.4 | 144.8 | 588.0 | 85.6 | 282.2 | 1497.0 |
| Secondary | CV2 | 142.8 | 191.7 | 180.1 | 186.6 | 134.9 | 836.1 |
| TOTAL | | 539.2 | 336.5 | 768.1 | 272.2 | 417.1 | 2333.1 |

* *Includes Fleet-Bramley scheme reported in CV25 high-value project BPDT.*

Table 6: summary of SSEN's LCT volumes and MW enabled in the ED2 period- Consumer Transformation (per year).

| LCT type | | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total |
|---|---|---|---|---|---|---|---|
| Heat Pumps | # | 73763 | 81073 | 95847 | 129955 | 131793 | 512,430 |
| | MW | 332 | 365 | 431 | 585 | 593 | 2,306 |
| EV charge points (slow) | # | 59210 | 75726 | 139211 | 139096 | 139176 | 552,419 |
| | MW | 414 | 530 | 974 | 974 | 974 | 3,867 |
| EV charge points (fast) | # | 688 | 838 | 1039 | 1285 | 1486 | 5,336 |
| | MW | 54 | 62 | 76 | 96 | 109 | 397 |
| PVs | # | 12464 | 13308 | 17372 | 21378 | 21566 | 86,088 |
| | MW | 47 | 51 | 66 | 81 | 82 | 327 |
| Other DG (G98) | # | 180 | 225 | 269 | 3663 | 3246 | 7,583 |
| | MW | 1 | 1 | 1 | 13 | 11 | 27 |
| DG (non-G98) | # | 540 | 634 | 536 | 318 | 271 | 2,299 |
| | MW | 540 | 635 | 535 | 318 | 271 | 2,299 |

As LCT growth is the primary driver of the significant amount of work for which we are planning in ED2, we have compared our baseline DFES projection against the FES to ensure that our assumption is both credible and robust. These comparisons are provided in Figure 4 and Figure 5 for heat pumps (HP) and electric vehicles (EV) respectively.

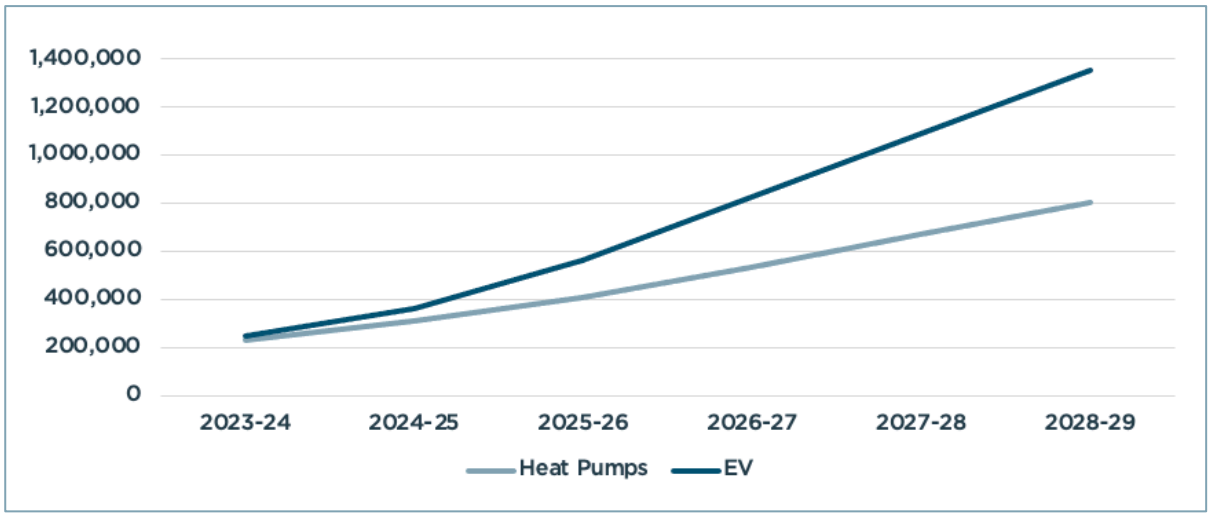


Figure 3 – Growth in EVs and heat pumps in SSEN area in the ED2 period (Consumer Transformation).

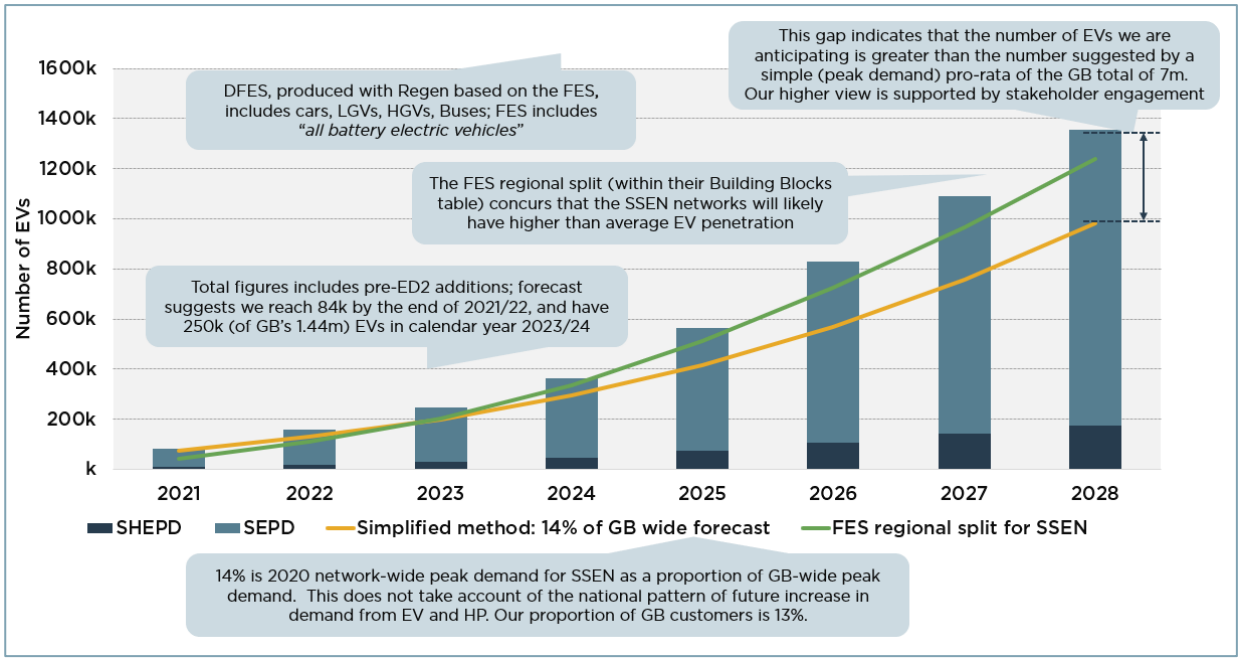


Figure 4 – Total number of Electric Vehicles in SSEN network area (2020 Consumer Transformation, DFES versus FES)

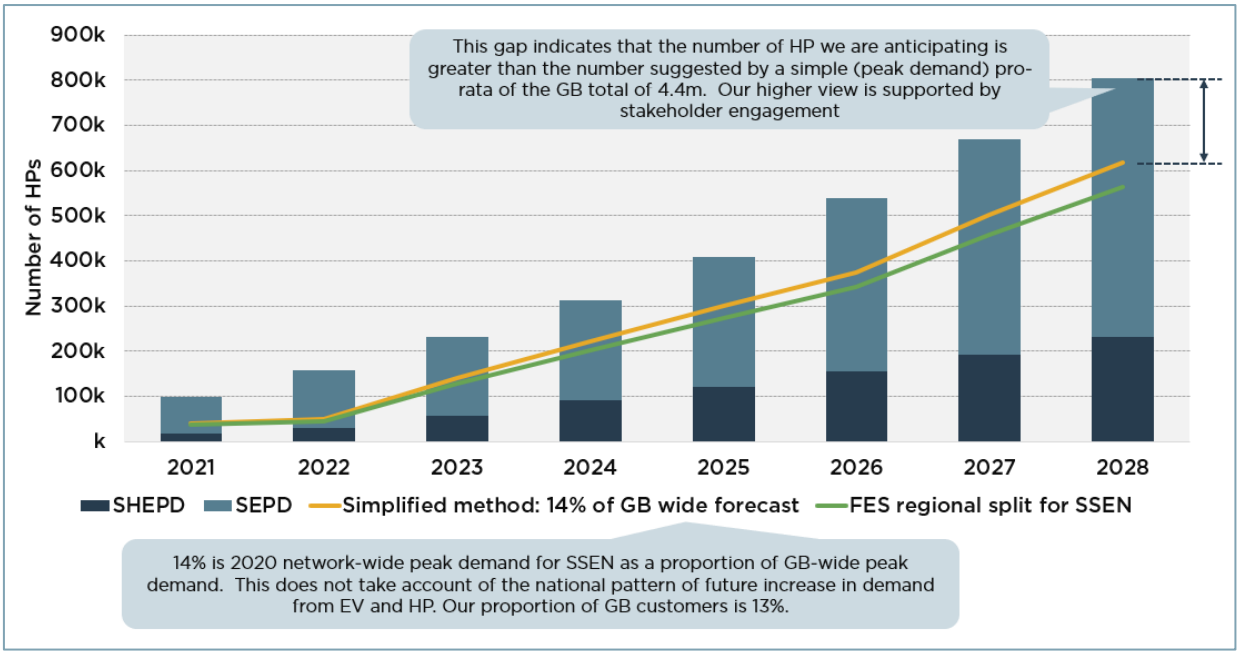


Figure 5 – Total number of Heat Pumps in SSEN network area (2020 Consumer Transformation, DFES versus FES)

As well as releasing capacity and enabling the connection of LCT, our investments will also provide further benefits to consumers. These include a positive impact on long-term network reliability associated with the number and duration of supply interruptions. This is a key consumer benefit metric which justifies our reinforcement decision in Cost Benefit Analysis (CBA), in addition to compliance with mandatory network planning security standards.

We understand the importance of demonstrating that our investment decisions are efficient throughout the ED2 price control period. In Figure 6 we summarise the number of primary demand groups in each of the load index ranking groups LI1-LI5, before and after intervention[11]. Figure 7 summarises the number of ground-mounted substation and pole-mounted substation sites falling within a set of utilisation bands, before and after intervention[12].

As a result of the increased demand we will, in the first instance, make greater use of our existing assets by procuring flexibility services. This will increase capacity utilisation and ensure that a greater percentage of our assets will be more fully utilised on the network, as shown in both Figure 6 and Figure 7. The shifting of the curve in the middle plots to the right from the 2021 position illustrates this. However, without network intervention the instances of overload, which can be a risk to network reliability, will increase. The right-hand plot in Figure 6 and Figure 7 shows the intervention benefits by reducing the occurrence of extreme asset overloading. Furthermore, these 'with intervention' plots are associated with our ex-ante baseline proposal. It is anticipated that the residual asset overload shown would be addressed and funded through uncertainty mechanism.

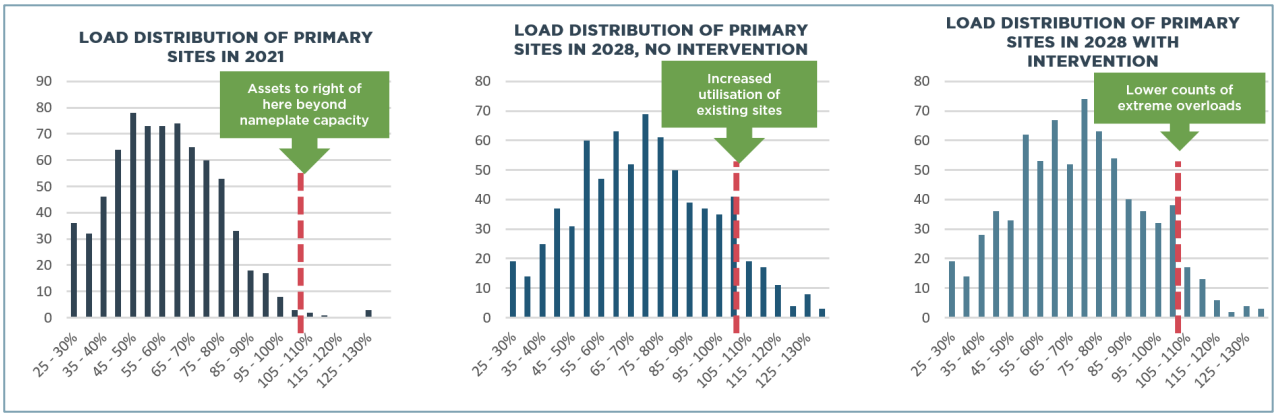


Figure 6 – Number of primary demand groups in each of the load index ranking groups before & after intervention.

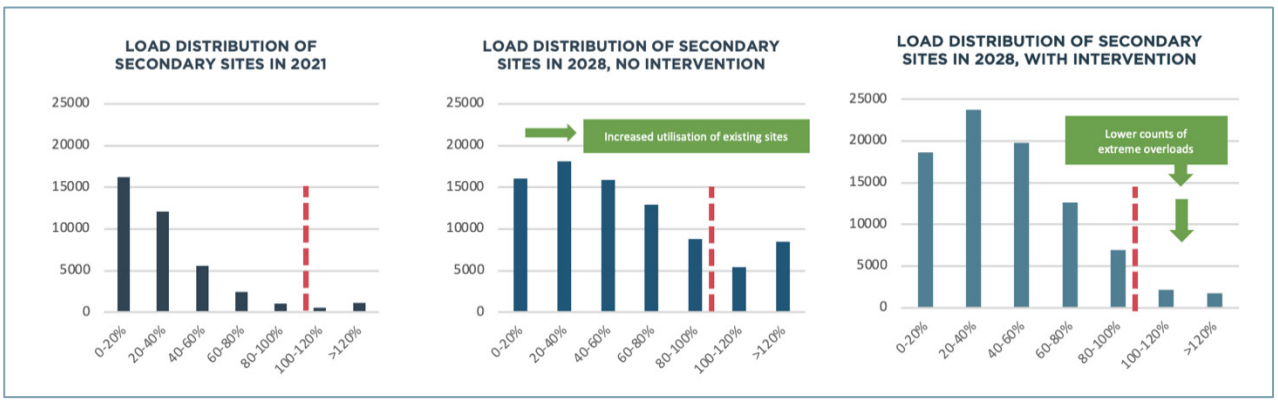


Figure 7 - Utilization of secondary assets with and without intervention

11 Data in Figure 6 is summarised from analysis conducted using the Consumer Transformation baseline scenario.

12 Data in Figure 7 is summarised from table CV2 memo tables using the Consumer Transformation baseline scenario.

### Network utilisation assessment

Network utilisation is one measure of the efficacy of our reinforcement expenditure decisions over the price control period.

At the primary network level, an established regulatory reporting measure is in place called the Load Index (LI). The LI categorises primary substations into five bands (LI1 to LI5) based on the percentage loading, or utilisation, of each substation. This loading percentage is the percentage of the substation firm capacity that is used at the time of maximum demand. At present, the LI metric is only applied to primary networks. This is mainly due to limitations associated with secondary substation monitoring.

Although subject to regular reporting, there is currently no formal regulatory output associated with network utilisation. One of the challenges is that there are multiple factors that can contribute to level of network utilisation.

For the ED2 period, Ofgem has indicated its intention to continue with LI reporting. In addition, Ofgem has asked DNOs to report *modelled*, as opposed to *measured*, network utilisation at the secondary network level – for both pole-mounted and ground-mounted substations. Modelled data is used in recognition of the limitation in the coverage of monitoring data at the lower voltage levels. We propose to increase measuring and monitoring coverage in ED2 – see **Network Visibility Strategy (*DSO Strategy, Annex 11.1, Appendix H*** for more details.

Discussions are ongoing between Ofgem, DNOs and industry stakeholders with regard to applying specific regulatory outputs for load indices and their interaction with allowances set through uncertainty mechanisms.

## 4.3 FAULT LEVEL REINFORCEMENTS & NEW TRANSMISSION CAPACITY CHARGES (NTCC)

Our ex-ante baseline allowance proposal for fault level reinforcement work will enable 262 fault level constraints to be resolved in the ED2 period. The number of fault level constraints resolved, disaggregated by asset type, is shown in Table 7[13]. Further disaggregation by solution type is provided in Section 5 of this document.

Table 7: Number of fault level constraints resolved by asset type

| Asset type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (#) |
|---|---|---|---|---|---|---|
| Switchboard | 83 | 0 | 37 | 0 | 0 | 120 |
| Circuit | 19 | 21 | 16 | 17 | 20 | 93 |

[13] Data in table is summarised from table CV3 in the business plan data tables.

Consumers will benefit from these interventions on the network, which aims to ensure that no assets operate at higher than 95% of their duty rating, or with fault level operational restrictions.

In Table 8[14] we outline a proposal to spend £23.2m across ED2 on New Transmission Capacity Charges. This is payment is to transmission licensees for projects which have been initiated by us but carried out by the transmission licensee.

We will continue to work closely with transmission licensees to ensure that transmission connection point capacity is made available at the right place and at the appropriate time to support and align with our requirement to faciliate net zero – this includes pursuit of Whole Systems apporaches and solutions.

In Section 5 of this annex we provide further detail on the actions which will be taken to deliver on these proposals.

Table 8- NTCC impact of our plan

| Asset type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (£m) |
|---|---|---|---|---|---|---|
| Reinforced | £2.6 | £4.0 | £5.0 | £5.7 | £5.9 | £23.2 |
| New | - | - | - | - | - | - |

## 4.4 FLEXIBILITY DEPLOYMENT

Flexibility services play a critical role facilitating the connection of Low Carbon Technologies (LCT) to networks as well as bringing value to the wider energy system through wholesale markets and in the provision of national system services for the Electricity System Operator (ESO).

The key benefit from the use of flexibility services in our business plan is in enabling the rapid uptake of LCT in a way that is efficient, effective and delivers value to customers in the long-term. Procuring flexibility services enables smart management of network capacity. It allows us to delay decisions to invest in conventional constructed solutions. This provides both deferred capital expenditure benefit, as well as realising the value of 'waiting' for more certainty of the need for network capacity in an otherwise uncertain future, thereby reducing the risk of long-life stranded assets.

Flexibility also enables us to increase the efficiency of the existing network through increased levels of utilisation, and to deliver enhanced Customer-Minutes Lost (CML) performance derived from flexibility-based restoration options. The use of flexibility enables us to directly reduce business operational costs and lower carbon emissions associated with the use of mobile and static diesel generation, and also delivers broader societal and community benefits associated with not constructing capital works (e.g. traffic disruption). This is further detailed in our Reliability Annex, 7.1 and our Deliverability Strategy Annex 16.1.

In addition, we expect the demand for major flexible connections to grow in ED2, and under our baseline scenario (CT) we expect to offer more than 200 new connections in the ED2 period, totalling 2GW.

[14] Data in table is summarised from table CV4 in the business plan data tables.

This will take our overall total of flexible-connected generation capacity to around 3.6GW by the end of the ED2.

We have considered the likely impact of the Access SCR 'minded-to' position on this growth forecast; we consider it reasonably to expect a reduction in the amount of enduring flexible connections; those where the level of flexibility is stipulated for the duration of the connection. However, we also consider it fair to expect a similar increase in *temporary* flexible connections, where a level of flexibility is agreed for the short to medium term while conventional reinforcement is delivered, enabling customers to connect to our network sooner. As such we have maintained our expectations of growth in flexible connections in ED2.

We have prepared our ED2 plan to deal with the full range of high and low uptake scenarios and the associated variation in network impact. We have prepared well-justified plans for conventional network investment where peak demand growth uncertainty is low and the customer cost of failure to meet LCT demand is high. At the same time, we are fully equipping ourselves with the capability to make effective use of flexibility services to enable us to deal efficiently with unexpected outcomes through full and supportive engagement in the developing marketplace. Flexibility services play a major role in our DSO Strategy[15].

We expect flexibility to deliver customer value at all levels on our network. At EHV our well-established flexibility arrangements will ramp-up in ED2 to ensure that the timing of investment in major schemes and projects is optimised and commitment to asset-based constructed solutions occurs only when required and when flexible solutions have been fully considered.

With significant increases in LCT (EV, heat pumps, solar PV) capacity anticipated in ED2 – and with the vast majority of these connecting at the customer and community level – accommodating, supporting and accounting for flexibility on our HV and LV networks will become increasingly important in the ED2 period. Furthermore deploying flexibility services at LV and HV has numerous advantages. It can defer conventional reinforcement and avoid capital expenditure and deliver benefits for customers in terms of both lower costs and more feasible and assured delivery of the reinforcement programme. Flexibility at LV can significantly reduce the winter peak demand growth that is driven by the uptake of LCTs.

On our lower voltage networks, our load-related expenditure proposals take full account of a range of different sources of flexibility, including domestic smart EV charging, domestic vehicle-to-grid; flexible heat from domestic heat pumps; the expected uptake in time-of-use tariffs, and a variety of energy efficiency interventions. A full and detailed account of our methodology for assessing the benefits of flexibility at HV and LV is provided in our DSO Annex[16].Table 9 summarises the scale of flexibility deployment we anticipate under Consumer Transformation, and the potential savings quantified from advancing these flexibility schemes[17]. This represents an estimated view of using flexibility services for EHV, HV and LV schemes, dependent on market liquidity.

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15 DSO Strategy, Annex 11.1

16 Ibid., Appendix G 'HV and LV Flexibility Methodology'

17 Not all benefit streams listed are quantified in this summary, due to the lack of industry wide agreement on quantifying the optionality benefit.

Table 9- Impact of flexibility on our Load plan under Consumer Transformation

| Summary- application of flexibility in Load | |
|---|---|
| CAPEX deferred beyond ED2 | £15.2 – 41.9m |
| CAPEX deferral savings in ED2[18] | £3.1 – 4.4m |
| Cost of procuring flexibility services | £5.1 – 6.5m |
| Flex Capacity considered | 649 MVA |
| Flex Capacity used | 176-208 MVA |

## Load Managed Areas (LMA)

LMA is a legacy system used to manage network capacity in the SHEPD licence area. LMAs reduce the maximum demand on circuits and at substations by controlling customer space heating and water heating load at different times during day and night via Long Wave Radio Tele-Switching (RTS). LMAs cover approximately 93,000 customers in rural areas. They were historically introduced as an alternative to traditional reinforcement in rural parts of the network where costs are prohibitively expensive.

Our approach in ED2 will be to use market flexibility services to replace LMA mandated switching patterns – including activities to define, develop and stimulate the market – alongside, and in accordance with, development and facilitation of flexibility markets to support DSO.

Solutions to provide additional capacity to support the uptake of LCT will be co-optimised with those to remove LMA restrictions – using the principle of 'flexibility first' We will also ensure that other reinforcement or flexibility procurement for other (non-LCT) needs or requirements provides for LMA removal, as a matter of course.

It is anticipated that the load-related investment in ED2 will ease or lift around 30% of the LMA restrictions by the end of the ED2 period, with the potential for up to 50% of restrictions lifted if higher levels of LCT materialise. The aim is to remove all remaining LMA restrictions during the ED3 period.

More detail on our proposed approach to removal of LMA restrictions is provided in Appendix C of this annex.

[18] Direct savings, as defined in the ENA's Common Evaluation Methodology, come from the benefit of delaying investment, hence accessing the time value of money being deferred- less the cost of procuring the flexibility.

# 5 WHAT ACTIONS WILL BE TAKEN TO DELIVER ON THESE PROPOSALS?

In this section we provide a breakdown of the investments underpinning our ex-ante baseline allowance proposal set out in Section 4. This is supported by a summary of our rationale supporting these proposals. Further commentary is provided in Section 6. Additionally, in sub-section 5.3 we summarise the business operational changes needed to realise the anticipated benefits.

## 5.1 PRIMARY AND SECONDARY NETWORK REINFORCEMENTS

The proposed ex-ante baseline funding associated with our primary network, as outlined in Table 3 will be delivered through a mixture of conventional, innovative and flexibility solutions across the 33kV primary network in the North and the 33kV and 132kV network in the South. Table 10 provides details of the total capacity released by different solution types for our North network, and Table 11 for the South network. A further breakdown is provided in Business Plan Data Table (BPDT) CV1[19].

Table 10: Capacity released on our primary network (North) aligned with our anticipated[20] load-related investment (CV1)

| Reinforcement type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (MVA) |
|---|---|---|---|---|---|---|
| Conventional | 90.2 | 18.3 | 54.0 | 6.1 | 19.1 | 187.7 |
| Flexibility | 2.4 | 4.0 | 3.7 | 4.5 | 0.1 | 14.7 |

Table 11: Capacity released on our primary network (North) aligned with our anticipated load-related investment (CV1)

| Reinforcement type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (MVA) |
|---|---|---|---|---|---|---|
| Conventional | 295.5 | 105.0 | 518.2 | 75.0 | 263.0 | 1256.7 |
| Flexibility | 8.4 | 17.5 | 12.0 | 0.0 | 0.0 | 37.9 |

On the secondary network, the ex-ante baseline funding outlined in Table 3 and associated capacity released outlined in Table 5 will be delivered through mixture of conventional and flexibility solutions.

The capacity released calculation at secondary level focusses on low voltage substations (11kV/LV) - both pole-mounted and ground-mounted. This follows a defined methodology that ensures no double-counting of capacity where multiple assets on a circuit enable the same capacity. There are a wide variety of solutions proposed in the plan which enable the capacity release shown in the tables.

19 Disaggregation in business plan data tables is by primary and secondary voltage of substations; by single substations and substation groups; and by level of redundancy on the network (N-1 or N-2).

20 This also includes capacity released from investments associated with high value projects as reported in CV25.

Table 12: Capacity released on our HV and LV networks (North) aligned with our anticipated[21] load-related investment (CV2)

| Reinforcement type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (MVA) |
|---|---|---|---|---|---|---|
| Conventional | 37.3 | 39.5 | 32.6 | 34.5 | 11.4 | 155.3 |
| Flexibility | 0.1 | 0.2 | 0.8 | 2.6 | 3.9 | 7.7 |

Table 13: Capacity released on our HV and LV networks (South) aligned with our anticipated load-related investment (CV2)

| Reinforcement type | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | Total (MVA) |
|---|---|---|---|---|---|---|
| Conventional | 102 | 147 | 132 | 114 | 65 | 560 |
| Flexibility | 3.4 | 5.1 | 14.7 | 35.5 | 54.5 | 113.2 |

## 5.2 FAULT LEVEL REINFORCEMENTS & NEW TRANSMISSION CAPACITY CHARGES (NTCC)

Our proposed ex-ante baseline funding includes delivery of solutions for fault level issues on the network. These solutions will be delivered through a mix of conventional and innovative solutions, such as: replacing the switchgear; increasing the size of cables; replacing transformers with higher impedance units and reconfiguring the network to split busbars. Some of the innovative solutions employed include fault current limiting devices, and real-time management of fault level. The specific solution is heavily dependent on-site specific factors which are discussed in the EJPs.

## 5.3 WHAT DO WE NEED TO DO AS A BUSINESS TO DELIVER OUR LOAD RELATED PLAN?

Our deliverability strategy detailed in ***Ensuring Deliverability and a Resilient Workforce (Chapter 16)*** of the Business Plan describes our approach to evidencing the deliverability of our overall plan as a package, and its individual components. Testing of our EJPs has prioritised assessment of efficiency and capacity, and this has ensured that we can demonstrate a credible plan to move from our ED1 performance to our target ED2 efficiency. We have also demonstrated that our in-house and contractor options can, or will through investment or managed change, provide the capacity and skills at the right time, in the right locations. This assessment has been part of the regular assessment of our EJPs, CBAs and BPDTs, and we will further refine our bottom up efficiencies and work plan phasing as we appproach the start of the ED2 period through the ongoing development of our ED2 Commercial and Deliverability Strategy and engagement with our supply chain.

Our deliverability testing has identified a major strategic opportunity which is relevant to all EJPs.

[21] Our 'anticipated' load-related expenditure includes Category 1b expenditure as shown in Table 3.

- In ED2 SSEN will change the way Capital Expenditure is delivered, maximising synergies within the network to minimise disruptions for our customers. This is particularly relevant for the ED2 price control period where volumes of work are increasing across all work types.
- The principle is to develop and deliver programmes of work, manage risk and complexity at programme level and to develop strategic relationships with our suppliers and partners to enable efficiency realisation.
- The Commercial Strategy will explore the creation of Work Banks (WB) and identify key constraints. The load-related work will be the primary driver for a WB, supplemented by non-load related work at a given Primary Substation. This approach will capitalise on synergies between the Load and non-load work, whereby the associated downstream work from a Primary Substation will maximise outage utilisation, enabling the programme to interact with the existing distribution system in a controlled manner with the objective of touching the network once. Where there is no primary load-related expenditure scheme to support the non-load related work, these will be considered and packaged separately, either insourced or outsourced dependant on volume, size, and complexity.
- Transparency with the supplier in terms of constraints, challenges, outage planning and engineering standards will capitalise on efficiencies, supported by a robust contracting strategy.

# 6 WHY DID WE CHOOSE THESE INVESTMENT PROPOSALS OVER ALTERNATIVES?

In Sections 4 and 5 we set out what consumers will get from our proposed ex-ante baseline allowance and what actions we will take to deliver these investments, respectively, along with a summary of our rationale supporting these proposals. In this section we provide a more expansive commentary of the methodologies we have used to develop our ex-ante baseline proposals, and why we are confident these proposals are in the interest of our consumers. We set out the key trends influencing our choice of load-related investment and what needs to be believed for these proposals not to be correct. We also assess how our future expenditure plan might need to adjust if there are changes in the assumptions upon which our ex-ante baseline plan is built. In Section 8 we set out our proposals for managing a different future to the one on which our plan is built.

Detailed EJP and CBA have been prepared to support this section. These give specific and extensive evidence on individual or grouped investments.

The content of this chapter is core to the demonstration of compliance with the Ofgem business plan minimum requirements[22].

In this section we set out the overall process which has been used to populate the load-related expenditure business plan data tables.

## 6.1 END-TO-END APPROACH FOR DEVELOPING OUR LOAD PLAN

We have followed a robust four step process to develop our load-related expenditure plan, as summarised in Figure 8. The four core steps of this process are consistent with the Load Related Methodology Guidance issued by Ofgem in April 2020 and is therefore consistent with the approach used across DNOs. Table 14 provides a top-level explanation of the process steps and in sub-sections 6.2 to  we give a comprehensive explanation of the methodology and our critical insights, including how these flow into the summary information presented earlier in Sections 4 and 5.

[22] Relevant minimum requirements as set out in Ofgem Business Plan Guidance Document, paragraph 5.1-1.5.25. Appendix A provides specific section detail on demonstration of our minimum requirement within the business plan.

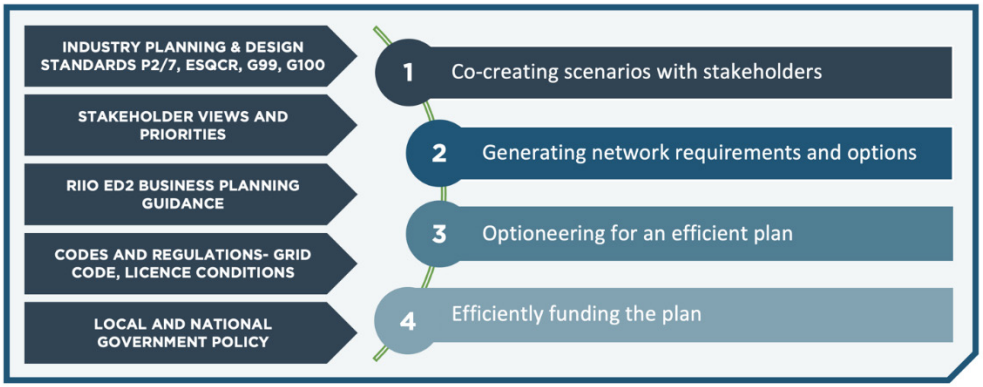


Figure 8- End-to-end process for generating ED2 load related expenditure

Table 14- Structure of this section (Section 6).

| Section | Content |
|---|---|
| 6.2 | **Co-creating scenarios with stakeholders**: Firstly, a discussion of how we co-created our understanding of the future with stakeholders through our enhanced engagement process. This explains our choice of scenarios, particularly our baseline scenario, and how we have used the scenarios to quantify the demand that the network is likely to experience in ED2, to support the journey to a net zero. |
| 6.3 | **Generating network requirements and options**: Showing how we have interpreted the scenarios in terms of network constraints and how we study these through power flow analysis to identify the need for network intervention. The range of options developed for addressing these intervention needs are requirements described. |
| 6.4 | **Optioneering for an efficient plan**: Assessing credible options and identifying the best option for consumers' interests is described, through the Cost Benefit Analysis process, and accompanying sensitivity analyses that increase confidence that our plan will deliver for consumers whichever pathway towards net zero is followed. |
| 6.5 | **Efficiently funding the plan**: Finally, a synthesis of how our ex-ante baseline plan, and the associated investments, come together. This is mapped to regulatory requirements and outputs; including expectations set out by Ofgem on categorization of expenditure. |

## 6.2 CO-CREATING SCENARIOS WITH STAKEHOLDERS

Our baseline plan is ex-ante and is based on a set of assumed changes to generation and demand connected to our network driving. This defines our forward view on the expenditure needed to manage the resultant constraints on the network. In Section 8 we discuss how our plan can adapt to changes in the ED2 period. Central to developing base-case expenditure is an understanding of the range of future pathways or scenarios which could credibly materialise, taking account of stakeholder views. This informs selection of an appropriate base-case view for the ex-ante plan.

Our future scenarios are based on the range of assumptions found in the net zero compliant energy pathways in the Electricity System Operator's (ESO) 2020 Future Energy Scenarios (FES)[23], and the Committee on Climate Change (CCC) 6th Carbon Budget[24]. We have used these key assumptions as part of determining the range of demand for our network over the ED2 period and beyond. Although the 2021 edition of the FES has now been produced and the distribution version is following, there has not been sufficient time in the programme to rerun the 3 steps that follow scenario creation in creating our load plan, so our submission continues to be underpinned by DFES 2020. This been agreed with Ofgem.

The scenarios produced by the ESO are set at the national level for all Great Britain. Whilst a top-level view of generation and demand by DNO licence area is provided it is necessary to create a more detailed bottom-up view which includes local intelligence and reflects relevant planning and development activities in our licence areas. For this purpose, we have produced a set of Distribution Future Energy Scenarios (DFES) using the same scenario framework as the ESO FES. The FES scenarios are shown in Figure 9.

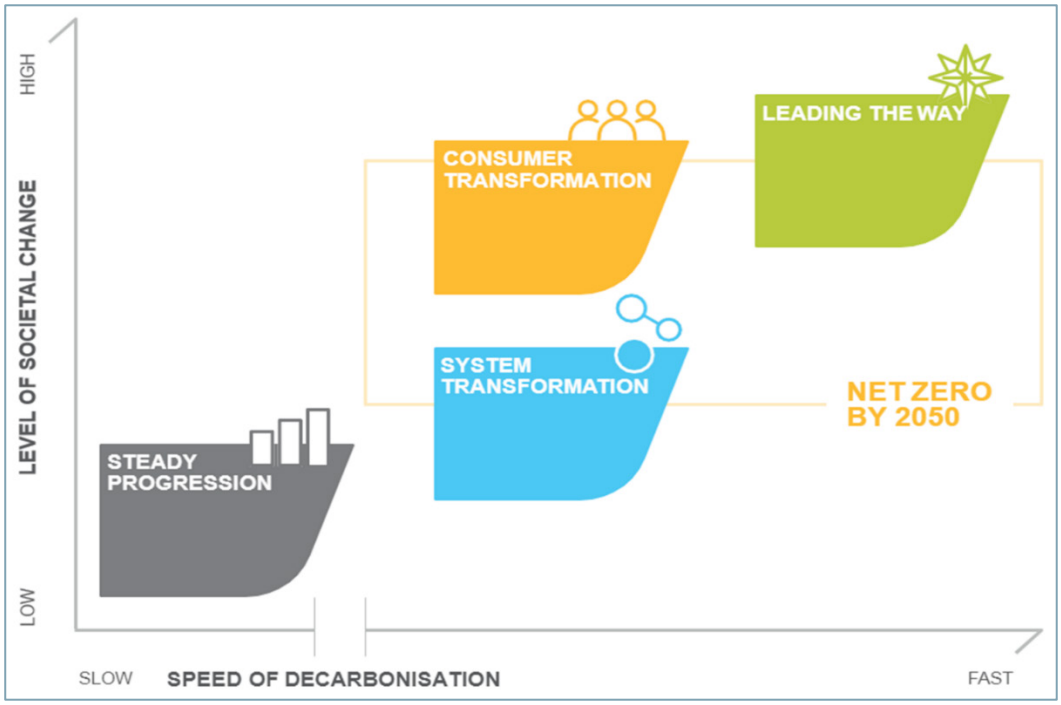


Figure 9 – Scenario Framework for FES and DFES *(source: National Grid ESO, Future Energy Solutions)*

23 https://www.nationalgrideso.com/document/173821/download
24 https://www.theccc.org.uk/publication/sixth-carbon-budget/

### The four Future Energy Scenario (FES) trajectories

- **Steady Progression**: Slowest credible decarbonization of all the scenarios with minimal behavioural change of consumers. Decarbonisation of power and transport but not in heat by 2050. It doesn't achieve a net zero by 2050 target
- **System Transformation**: Meets net zero by 2050 but with consumers less inclined to change behaviour and lower uptakes of energy efficiency compared to the other net zero complaint scenario. Supply side flexibility is prominent as is hydrogen for heating
- **Consumer Transformation**: Meets net zero by 2050 but with shifts in consumer behaviour driving; including high uptakes of energy efficiency and demand side flexibility and electrified heating
- **Leading the Way**: The fastest credible decarbonization pathway. Centred on significant lifestyle changes for consumers; but a mixture of hydrogen and electrification for heating

A first critical step we have undertaken with our stakeholders is to create a bottom-up DFES framework from the ESO national FES framework. This is an annual process and is carried out separately for each of our licence areas with the support of consultancy Regen[25]. In December 2020 we produced detailed DFES reports for our two licence areas:

- **DFES Report - North**
- **DFES Report - South**

Our DFES each year is co-created with our stakeholders. Over the near term the DFES projections are heavily influenced by the pipeline of projects and new developments that can be identified in the planning system, our connections database and by direct discussion with developers and stakeholders. Over the medium and longer term the projections will tend to reflect the underlying scenario assumptions and degrees of certainty supported by regional and national policies.

- The DFES assessment is a locally driven and evidenced-based analysis of the future energy scenario outcomes for a specific region. Stakeholder engagement and consultation is therefore critically important to inform the scenario modelling and test the future assumptions that have been made for the various building block technologies. Through engaging and consulting with a wide range of organizations and representatives we have been able to seek views and evidence in the following areas.
- Individual project development plans and timescales;
- Regional considerations for the potential uptake of specific technologies;
- The viability of use cases and business models that would align with assumptions made around increased uptake or reduction of technologies connecting to the network;
- Specific regional policy, regulation and other decision making that could affect both the near-term and long-term trajectories for specific technologies, such as wind planning policy, electric vehicle charger deployment or heat pump uptake

25 https://www.regen.co.uk/

To further enhance the scenario modelling and to allow stakeholder engagement to continue, we approached Local Authorities[26] with the results of the DFES projections to create a modified baseline scenario. The relevant data for each Local Authority (LA) was provided with a request for LAs to self-select the scenario which best represents the local view of the projection for four of the most impactful low carbon technologies. All Local Authorities have been asked to evidence their selection, with each being assessed in accordance with an open and transparent evidence assessment framework. Further details of our assessment framework is provided in Appendix B.

Our stakeholder engagement activity has enabled us to develop a number of key load-related assumptions:

- Renewable energy generation capacity is very likely to significantly increase;
- Unabated fossil fuel electricity generation is very likely to continue to decline;
- The shift to more decentralised energy assets will continue to some degree;
- The electrification of transport is already in progress and will accelerate;
- Hydrogen has a key role to play for industrial processes and some forms of transport;
- Further energy efficiency deployment is vitally needed in both homes and businesses;
- The electrification of heat will increase although there remains a key uncertainty over the role that hydrogen boilers could play

Table 15 sets out a number of key stakeholder entities with whom we have engaged on our load-related proposals.

Table 15 – key stakeholder engagement parties.

| | |
|---|---|
| Sector-specific stakeholder consultations | We engaged with individual companies and industry representatives to better understand the projections for specific technologies. This included representatives many organizations, including but not limited to: |

26 This occurred in January 2021 and will continue as part of Final Business Plan submission and thereafter as part of regular business-as-usual planning processes.

| | |
|---|---|
| **Engagement with the Scottish Government on DFES** | At the end of October 2020, we met with Scottish Government officials to discuss the assumptions and DFES technology scenario projections for the North of Scotland licence area; and to road-test the DFES assumptions and some early modelling results. This helped to clarify how Scottish Government energy policy targets and decarbonisation strategies should be reflected in the DFES analysis. Through this engagement with Scottish Government in both the workshop and from reviewing the Climate Change Plan Update issued in December 2020, the DFES scenario analysis has been influenced (either directly or indirectly) by several targets, aims and milestones. The adjacent call-out box provides further details on how we have specifically accommodated Scottish government feedback.<br>In addition, we have received written confirmation from Scottish Government supporting Consumer Transformation (CT) as the basis for a credible forward view of electricity distribution demand in the SHEPD licence area. |

### How our scenario modelling has accounted for Scottish Government feedback

- **Electric vehicles & chargers**: Our Consumer Transformation scenario is consistent with Transport Scotland's projections on EV number;
- **Heating**: The Scottish government have a target for 50% of homes with zero carbon heating by 2030. Our Consumer Transformation and Leading the Way scenarios include 77% of homes with a heat pump variant by 2045; along with strong near-term uptake of air source heat pumps and a minimal adoption of hybrid heating, which is also consistent with Scottish government views;
- **Onshore wind**: Our scenarios align with the Scottish government target to have 50% of energy to come from renewable sources in Scotland by 2030;
- **Fossil fuel generation**: In all scenarios we have limited additional gas reciprocating engine capacity connecting in 2020s DFES decommissioning of all unabated natural gas generation by/before 2045. This ensure alignment with Scottish government targets. We have also removed island diesel generation from the scope of DFES, due to special role they play in maintaining island security of supply in Scotland
- **Hydrogen electrolysis**: Reviewed and reflected Transport Scotland Rail Decarbonisation Action Plan and the outcomes of the Hydrogen Assessment Project in electrolysis scenario uptake and geographical distribution.

## 6.2.1 Key Trends in our Scenarios

The full DFES documents for 2020 in the North and South should be consulted for a detailed analysis of technology evolution across our licence areas. In Appendix E we summarize some of the most important trends central to our analysis for the ED2 period.

### Selecting our baseline scenario to drive ex-ante baseline investment proposals

Whilst we look across multiple scenarios to determine our investment requirements for the EDA period and beyond our business plan submission is ex-ante based on a single set of scenario assumptions. The choice of scenario assumptions is defined with input from our stakeholders to represent a credible baseline trajectory of supply and demand change in the ED2 period. This in turn drives our network needs and investment proposals. We know of course the future could be very different to this projection, and so in Section 8 of this annex we set out our proposals to manage any resultant differences within the ED2 period.

In November 2020 and again in January 2021 we undertook sessions with our stakeholder community to present our DFES scenarios. We articulated key net zero ambition levels such as number of EV chargers and heat-pumps. We also shared relevant data for each local authority, and devolved administrations; and asked stakeholders to self-select the scenario which best represents their view of the projection for four of the most impactful technologies. With the evidence received we were able to select a baseline scenario which is representative of most stakeholder needs. In Table 16 we highlight key findings from this engagement and how it helped us select a baseline scenario.

Table 16: summary of stakeholder views to drive selection of baseline scenario to determine ex-ante investments

| Engagement detail | Insights derived |
|---|---|
| **Scottish Government (Energy and Climate Change Directorate)**<br><br>We collaborated with the Scottish Government through a series of bilateral meetings to identify the most appropriate Distribution Future Energy Scenario (DFES) to use as a baseline for ED2 planning | ▪ The Scottish Government see that SSEN has a substantial role in supporting their statutory targets<br>▪ The Consumer Transformation DFES scenario is most closely aligned with the Scottish pathway to net zero, although Leading the Way is also relevant<br>▪ For battery electric vehicle (EV) uptake, the expectation is that the future pathway will be between the Consumer Transformation and Leading the Way DFES scenarios<br>▪ For the decarbonisation of heating, while the Consumer Transformation scenario is closest to the ambition, there is likely to be a need to go further and faster than this. Reliance on hybrid heat pumps (from Leading the Way) does not correspond with their plans<br>▪ Renewable generation capacity is projected to be between Consumer Transformation and Leading the Way scenarios so the ability to flex these both up and down to meet the outturn is important |

| | |
|---|---|
| **Local Authorities**<br><br>We provided LAs with DFES data for their area for EVs, Heat Pumps (HPs), PV, and battery storage and asking them to assess which DFES most closely matched their plans | ▪ The majority of LAs (75%) who responded with selected Consumer Transformation or Leading the Way scenarios<br>▪ 10% of councils told us that they could not provide a response or could not do so yet<br>▪ Some LAs are working in regional groups on their climate change response, for example, Oxford city, Vale of White Horse, West Oxfordshire and South Oxfordshire; BCP Council (Bournemouth, Christchurch, and Poole) is producing a single plan with Dorset Council<br>▪ We are maintaining an open relationship with LAs to gather further evidence as their plans develop – this is likely to inform our use of uncertainty mechanisms |
| **Local/community energy schemes, Consultants/Contractors, Local authorities**<br><br>We worked with Regen to engage stakeholders via separate online workshops for our North and South regions plus a follow-up survey to co-create projections for future network capacity based on several factors | ▪ It was noted by local authorities that local government can supply local information and help shape plans but SSEN needs to inform on requirements to meet 1.5C targets<br>▪ Local authorities expressed the view that SSEN should engage with them, local energy agencies, local developers, and should look at Local Energy Plans<br>▪ It was also stated that SSEN needs to inform on what is necessary to meet 1.5c then understand what can be done locally to achieve this<br>▪ On several occasions local authority representatives thought local government needs to engage in conversation and provide as much evidence as possible. However, it was accepted they were short in resource and time and may not be able to provide sufficient evidence for reinforcement decisions<br>▪ 75% of local authority representatives that participated in the local network plan survey agreed with our approach of using credible 'base' scenario for electricity demand on the network and modifying where there is strong local evidence<br>▪ 88% participants in the same survey felt that adjusting network plans and investment aligned with local authority plans was a fair approach given investment costs will be socialised across consumer groups and geographies<br>▪ Stakeholders encouraged SSEN to collect evidence for network planning through public consultations with Community Councils |

We know though that many of the targets and ambitions of our stakeholders are continuing to evolve and will be dependent, to a certain extent, on our agreed baseline plan. Where this is the case uncertainty mechanisms will provide the funding route for additional investment required.

### 6.2.2 Peak demand in our ex-ante baseline scenario

The modelling of peak demand in our scenarios is critical; and in the ex-ante baseline scenario it is central to our identification of network constraints and requirements for resultant investments. Peak demands typically represent the most onerous conditions under which the network must operate and so usually this defines the network planning criteria. Peak demands typically occur in the winter, but not always. In Section 6.3 we provide further detail on how we use peak demand data to model network constraints, and in Section 6.4 we describe the resultant process for optioneering on available solutions.

In this section we focus on articulating the building blocks to the peak demand. Understanding these building blocks is important as it provides an understanding of the underlying drivers of network constraints and so can help reveal the availability and applicability of options available to manage the resultant constraint.

It is important to note that whilst the notion of a system-wide GB peak demand is often commented upon within industry its use for network planning for a distribution network is limited. This is because each part of the network and asset will experience a different peak, which often occurs at a different point in time from the overall peak. Furthermore, the notion of a licence area-wide peak demand is also misleading as all individual substations will experience a peak demand uniquely driven by the type and volume of connected technologies.

For this reason, we study the peak demand at various points on our network to understand the investment implications. Figure 10 provides a case study example of the modelled peak demand at typical secondary substations on our network in 2028 for the Consumer Transformation scenario. The figure highlights the impact of two key components of future demand, Electric Vehicles (EVs) and Heat Pumps (HP). It highlights that in this scenario at the LV feeders the impact of EVs will have a more pronounced impact on peak, whilst at the HV feeders the impact of HPs is more pronounced. This impact of diversified charging profiles for EVs is the biggest factor contributing to the change in impact between LV and HV. With higher volumes of EVs feeding into the HV feeder and the impact of smart charging the peak impacts can be tempered; whilst for HPs the level of diversification is lower.

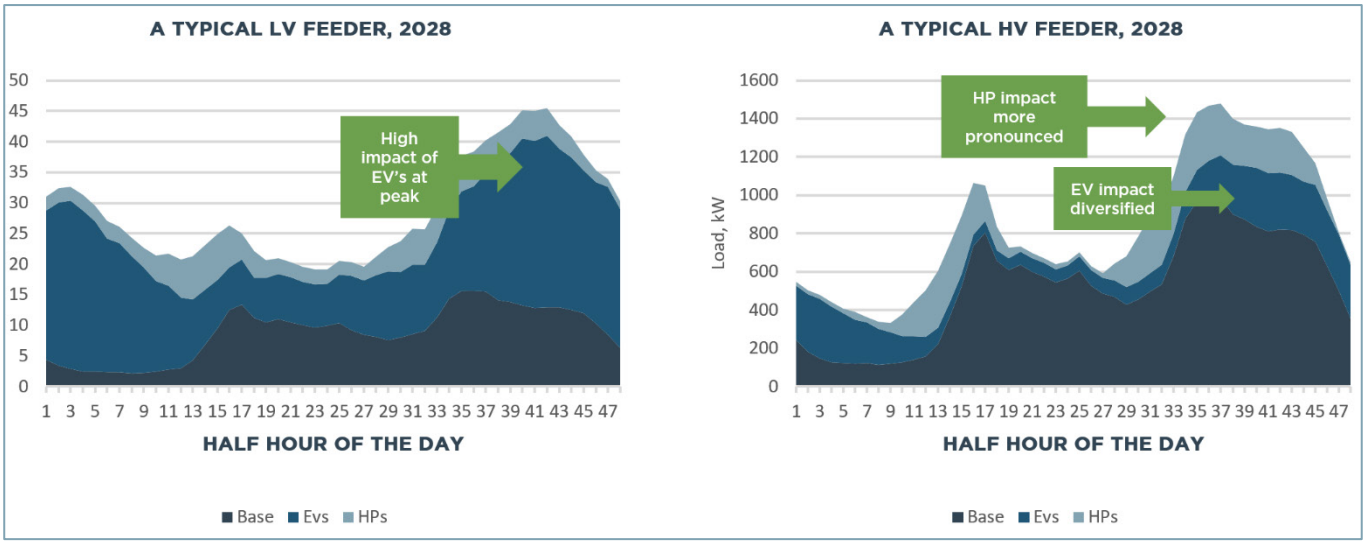


Figure 10: Example of peak demand at typical secondary substations

When undertaking a future looking assessment of peak demand two components are vital to understand:

1. The existing peak demand at a particular point on the network
2. how different technologies in the scenarios contribute to peak demand

The extent to which we can accurately determine the existing peak demand on our network differs at the various levels of the network. For the primary network our level of network monitoring is more extensive than the secondary network. This means that for secondary network alternative approaches are required to estimate the peak. We have made use of a range of techniques to do this, including machine learning, data cleansing and repair and geospatial outlier detection in order to generate a complete picture of conditions on all of our secondary assets. This is described further in this section.

To understand the how different technologies in our scenario add to (or adjust) the peak demand we need to understand four factors:

1. The distribution of different LCT types connected across the voltage levels on our network (e.g. a commercial car park EV rapid charge point may connect directly into a low voltage secondary transformer rather than be connected to an existing LV feeder)
2. The number of LCT units (MW) of each type connected at each point in the network, according to the scenario
3. The size or rating of the technology type connected at each point on the network
4. The profile of demand for the LCT type connected at each point on the network

Using the above four factors and the existing peak demand we can calculate the future peak demand at a particular point on the network according to the high-level equation:

$$\text{Future peak demand} = \text{Existing peak demand} \pm \sum_{\text{technologies connected}} (\text{Demand profile} \times \text{number of units of technology} \times \text{standard unit of technology})$$

The remainder of this section is devoted to articulating our approach to setting each of these components at the different voltage levels.

## Existing peak demand

At primary voltage levels we have extensive monitoring which means we are able to provide an accurate view of existing peak demand at key points on the network, and to use this as the basis for future demand scenarios.

At the secondary level (11kV and LV) we use highly granular assessments (down to street level) of future deployment of LCT, together with an innovative, data-led, analytical approach in order to identify local community network 'hotspots. These hotspots form the basis of further, more detailed, network studies as the basis for the HV and LV ED2 investment plan. Furthermore, we have used advanced artificial intelligence and additional data analytics to help fill and validate data gaps at HV and LV with a high degree of confidence[27].

Historically, and for good economic reason, the secondary voltage network, and the associated network assets, do not have the same coverage as the primary voltage network – particularly in terms of data, information, monitoring and control. This 'need' is rapidly changing. Improved understanding and control of the secondary network is a prerequisite for the development of a distribution system which can accommodate LCT and facilitating the markets needed to achieve net zero. More detail on our proposed increase in the use of LV monitoring can be found in our Network Visibility Strategy[28].

The roll-out of enhanced monitoring is a key deliverable for the ED2 period; however an approach to determining current peak on the secondary network is needed to develop the ED2 ex-ante plan submission.
Our three-step approach to determining secondary network demand has applied machine learning techniques to determine the loading on the network using a combination existing data monitored data on the secondary, smart meter data, customer profile data and known information on network topology to derive demand based on common customer profiles.

The three steps applied to calculate the demand on the secondary network:

1. Bottom-up approach modelling individual customer behaviour, making use of industry standard models;
2. Top-down approach that starts from known aggregated demands at higher voltages and distributes these among customers at lower voltages; and
3. Review of maximum demand indicators, where available ground-mounted transformers, to complement our bottom-up and top-down assessments

Figure 11 shows the confluence of the bottom-up and top-down approaches.

[27] Our methodology and approach for determining our expenditure plans on the secondary networks was independently reviewed and assessed by TNEI in February 2021.

[28] DSO Strategy, Annex 11.1, Appendix G.

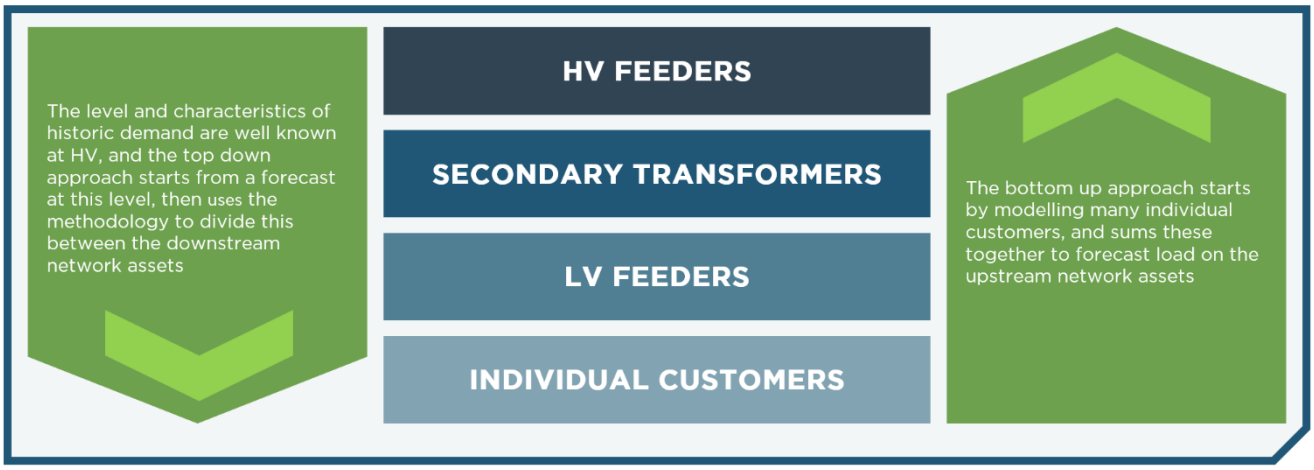


Figure 11- Bottom up and top down approaches to HV & LV demand estimation

The bottom-up approach calculates the demand using a combination of customer data and standardised profiles of customer usage. We achieved this using a combination of customer Estimated Annual Consumption (EAC) data and half-hourly profiles from EA Technology's WinDEBUT software[29]. These profiles are based on the ELEXON customer profile classes shown in Table 17.

Table 17 – Elexon profile classes

| Profile Class | Description |
|---|---|
| 1 | Domestic Unrestricted Customers |
| 2 | Domestic Economy 7 Customers |
| 3 | Non-Domestic Unrestricted Customers |
| 4 | Non-Domestic Economy 7 Customers |
| 5 | Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of less than 20% |
| 6 | Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30% |
| 7 | Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40% |
| 8 | Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40% |

This method enabled us to estimate the demand of each of our customers and scale-up to calculate the current load on our network assets. We recognize the importance of applying diversity when assessing LV feeders and HV/LV transformers to allow for differences in customer peaks. Figure 12 provides a typical example of how diversity has been applied in our LV load calculations.

29 WinDebut provides industry-standard consumption shapes for different type of customers. When multiplied by an estimated annual consumption in kWh, they produce a scaled shape of consumption power in kVA.

### Definition of demand diversity

In network planning, the peak loading of assets is critical. This is driven by the simultaneous use of the network by many customers; however when considering large groups of customers, a key factor is that they do not all use the network in the same way at the same time; this leads to a 'smoothing' of demand over different time periods that occurs as more and more customers are connected to assets further up the network. This is known as diversity, and substantially reduces network requirements compared to if all customers' peak usage of the network happened concurrently.

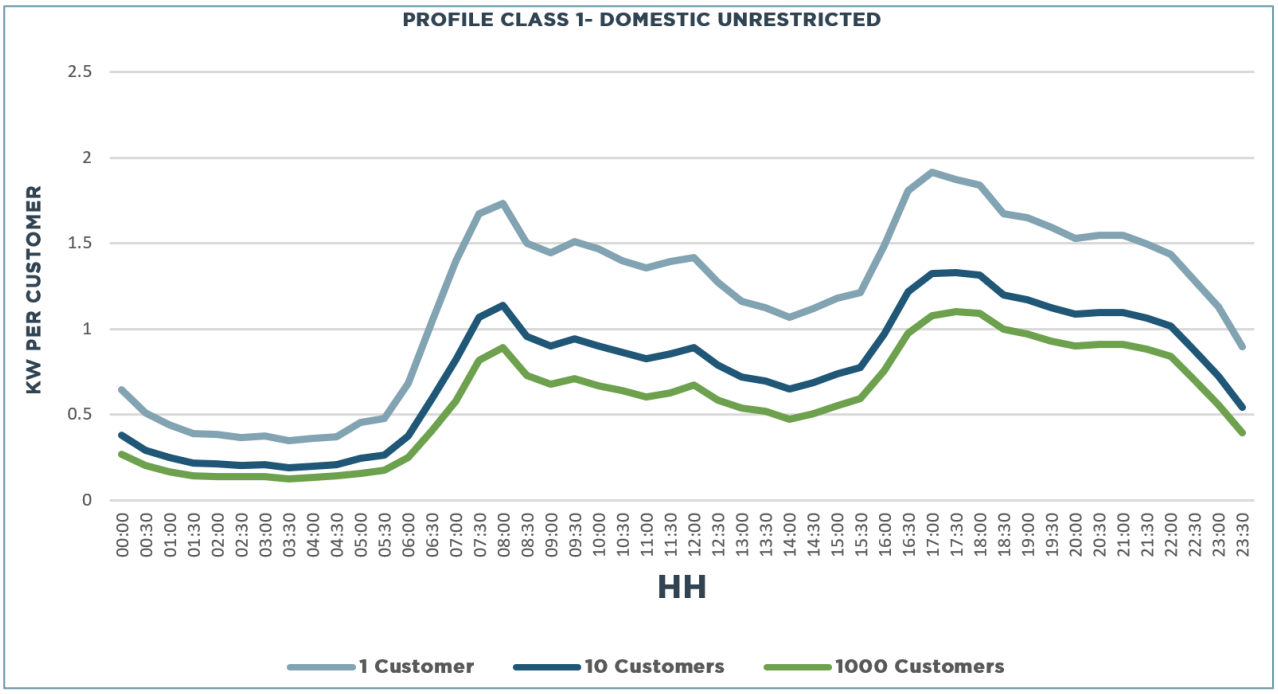


Figure 12: How diversity is applied on our LV load calculations

Our top-down approach used the winter maximum demand recorded from our HV feeder circuit breakers. This is a data set we have relatively high coverage off across the network. The sum of customers EAC, per LV feeder and distribution transformer respectively, is used to proportion the HV feeder demand across the LV network.

Bringing the bottom-up and top-down data together with the maximum demand indicators, on ground-mounted transformers we are able to determine an average demand on the LV assets on the network. Available LV monitoring data is used as a benchmark to validate. Figure 13 illustrates the difference between the LV substation monitoring data and the developed load estimate methods. We have found that the average between the approaches is relatively consistent to the data available from LV monitoring. Therefore, the average between the approaches is used as the baseload for LV feeders and secondary distribution transformers.

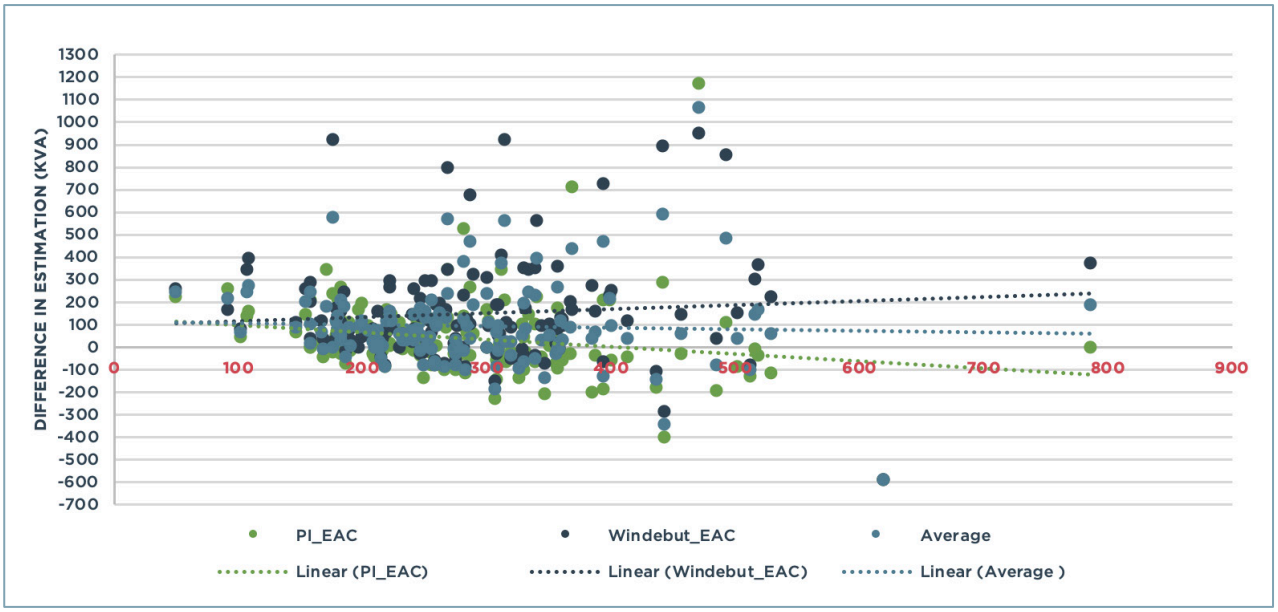


Figure 13 – LV demand calculation approaches.

## Technology demand profiles

A technology demand profile represents the typical underlying utilization characteristics of the technology which in turn help us to understand the contribution it has on peak demand. Each technology has a different utilization profile and, in some cases, there can be subset of utilization profiles. For example, EVs have complex potential behaviour. They have the characteristic of being a moveable source of demand, which can have different impacts on the network depending on the charging mode- the underlying model we've employed holds different profiles for eight 'types' of charging to reflect this, as shown in Table 18. In Table 19 we outline key technology types and the source of the underlying peak profiles used.

Table 18: Different modelled charging methods that contribute to peak demand forecasting

| Charging mode | Description |
|---|---|
| Domestic off-street | Charging on private driveway/in garage |
| Domestic on-street | Charging on a public street outside home |
| Workplace | Leaving EV connected at workplace |
| Fleet | Where EV is part of a commercial enterprise, such as a hire car or taxi |
| En-route local | Where charging occurs during a local journey |
| En-route national | Where charging occurs during a longer journey, ie using motorway services |
| Destination | Where charging occurs at a location a consumer is visiting (and the purpose of the visit is unrelated to charging) |
| Car park | Where charging is provided at a car park |

Table 19: Sources for demand profiles for key technologies in our analysis

| Technology | Source for demand profile |
|---|---|
| Domestic development | Profiles are taken from UK Standard Load Profile used for utility pricing (domestic = class 1) scaled to give an average power consumption of 0.53kW, which equates to an annual electricity consumption of 4600kWh (typical for a higher consumption property) |
| Non-domestic development | Profiles are taken from existing customer connected to our network; we have few different types of non-domestic developments |
| PV, gas, and diesel generation | Profiles are representative of existing customer connections |
| Battery & other generation | Flat profiles are used |
| Onshore wind and hydropower | Profiles are representative of existing customer connections |
| Air conditioning | Profile taken from Treidler, B. and Modera, M. (1994), Peak Demand Impacts of Residential Air-conditioning, Proceedings of ACEEE 1994 Summer Study on Energy Efficiency in Buildings |
| EVs | Profiles are sourced from the 2019 Elementenergy **Electric Vehicle Charging Behaviour Study** for National Grid ESO, with SSEN modifications applied to align with Regen data |
| Heat pump | Profiles taken from **Customer-Led Network Revolution** trials |

## 6.2.3 Distribution of technology types

The number of units connected is a function of the scenario trajectories and is fully described in each of our DFES 2020 documents for our SHEPD (North) and SEPD (South) licence areaa. The distribution of technologies by voltage level is in accordance with Table 20.

Table 20: Technologies connected by voltage level

| Connection point | Technologies connected |
|---|---|
| Primary to 11kV substation | ▪ Electricity generation except rooftop PV<br>▪ All battery storage<br>▪ Hydrogen electrolysis<br>▪ Air conditioning<br>▪ New housing and commercial property developments<br>▪ EVs – HGVs, buses, motorcycles. |
| Low Voltage secondary substation 'Transformers' | ▪ Commercial EV chargers (Car park; Destination; En-route local; En-route national; Fleet; Workplace)<br>▪ Non-domestic heat pumps |
| Feeder lines to consumers | ▪ Electric Vehicles – Cars<br>▪ Electric Vehicles – LGVs<br>▪ Domestic off-street chargers<br>▪ Residential on-street 7kW chargers<br>▪ Heat pumps (hybrid and non-hybrid)<br>▪ Small scale Rooftop Solar < 10 kw<br>▪ Direct electric heating |

Table 20 shows how the scenario projections for LCT have been distributed down to the level of secondary distribution 'transformer' sub-station, or to individual LV feeder lines which serve individual or small groups of consumers. This level of granularity corresponds to post code or street level analysis. Although the distribution of technology deployments is based on high-level scenario assumptions and distribution factors, it still allows for our network planning function to consider the potential impact of demand and technology changes on the low voltage network, and to understand the scale and range of network reinforcement that might be needed.

The distribution factors that underpin the spatial analysis, are based on data gathered from a wide range of datasets including Ordnance Survey Address base, road traffic flow data, Census Output Area data including affluence and demographic data, postcode statistical data, and individual property Energy Performance Certificate data. The distribution analysis uses affluence as one of the key factors driving the uptake of low carbon technologies. This is based on previous new technology deployment trends and empirical evidence that the uptake of low carbon technology has, to date, tended towards more affluent areas. For EVs, it is also based on the very practical consideration that, in the near term at least, the availability of off-road parking is a key driver for EV adoption.

To provide a degree of balance in the analysis the following approach has been taken.

- Affluence is considered a key distribution factor in the short term for Consumer Transformation and Leading the Way. For the Steady Progression and System Transformation scenarios, which have lower social interventions, affluence remains a stronger driver in the medium term;
- Over the medium and longer term, for the higher ambition scenarios, the impact of the affluence distribution factor is reduced, and an assumption is made that the deployment of LCT technologies will become more ubiquitous and will follow the underlying factors;
- For solar PV and heat pumps, the scenarios specifically include a social housing weighting factor to counter purely affluent areas. This social housing impact has previously been documented in Regen's DFES studies;
- For the more ambitious scenarios, from mid to late 2020s, the underlying assumption is that EVs will become ubiquitous. Therefore, the growth in demand for EVs in both on street and off-street areas begins to increase at equivalent rates.

### Annual energy consumption by LCT type

We have used a series of industry standard data points to inform the annual energy consumption of different key technologies contributing to the peak demand. These values are converted into a peak loading contribution using the technology demand profile, noted above. In Table 21 the standard units of annual energy consumption by technology is shown.

Table 21: Standard units of annual energy consumption by technology connected and peak.

| Technology | Standard annual energy consumption (kWh) | After diversity maximum demand, ADMD (kW) |
|---|---|---|
| Average household | 3200 | 1.9 |
| Average household with 'Economy 7' heating | 8500 | 4.9 |
| Heat Pump electric backup (average winter) | 3.5 | 3.4 |
| Heat pump gas backup (average winter) | 3.5 | 3.2 |
| Direct electric heating (average winter) | 3.5 | 3.2 |
| EV at home charging | 7 | 7 |
| EV destination and car park charging | 15 | 4.2 |
| EV workplace and depot | 36 | 4.6 |
| EV en-route - national and local | 150 | 51.8 |

## Reconciliation of DFES and FES

We have developed a comprehensive DFES framework to represent the needs and feedback of our local stakeholders in our licence areas. This framework was built this from a starting point of a central framework of scenarios developed by the Electricity System Operator (ESO). Each DNO for their licence areas has undertaken a similar, yet independent, process. However, there is an inherent risk in the DFES envelope that each company builds that when summed the total is not aligned with the national trajectory set within the envelope of the FES scenarios. This is further complicated if further regional adjustments are made to the scenarios post-publication for the purpose of setting an ex-ante plan.

To measure alignment between our DFES envelope and the national FES we have compared our data on key demand growth technologies for the ED2 period, namely EVs and Heat Pumps to a disaggregated view of the National FES from data sets published on the ESO website by DNO. Figure 14 shows the comparison for all companies between reported number of EVs and HPs in DFES publications and the national FES disaggregated view.

For SSEN we have not adjusted our DFES range for the purpose of preparing our ED2 plan, therefore as demonstrated by Figure 14, we are fully aligned with the national FES view on our projections of heat pumps and largely aligned with projections on EVs.

Our higher scenario projections for EVs assumptions are outlined in our DFES publications. Given our limited visibility of other company business plans we are unable to comment on whether the DFES ranges publicly reported have changed for the purposes of their business plans.

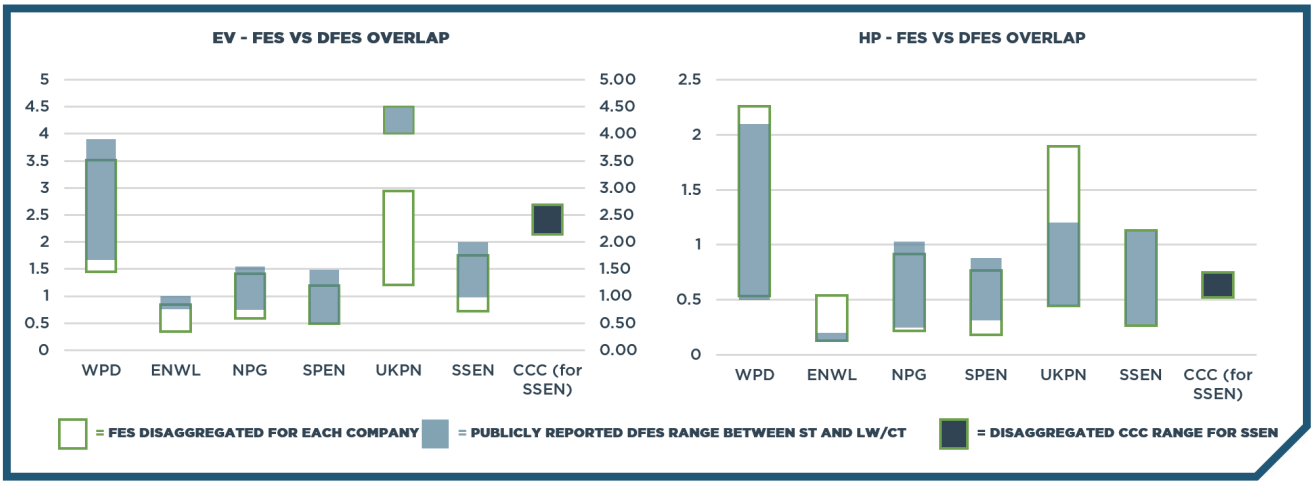


Figure 14 - Comparison of DFES to National FES on key technologies

## 6.3 GENERATING NETWORK REQUIREMENTS AND OPTIONS

In Section 6.2 we describe the changes to supply and demand connected to our networks. We focus on articulating how we use scenarios co-created with our stakeholders to understand credible pathways to reach net zero. We articulate why we think Consumer Transformation is credible as a stakeholder-supported scenario on which to base our ex-ante plan. Finally, we articulate how we determine the peak demand and reconcile our scenario view with the national FES.

In this section we describe how we generate a view on future network constraints through the scenarios, and how we identify the options available to remedy. In Section 6.4 we describe the optioneering process to select the most economic and efficient investments.

### 6.3.1 Principles of defining adequate network capacity

In order to ensure that sufficient network capacity is available where and when needed to actively support our local communities in contributing to the achievement of net zero, our approach is to design the network whilst adhering to three criteria:

1. Ensure compliance with industry security planning standards and related regulation
2. Invest in local network capacity sufficiently to meet customer needs whilst preventing overloading of our equipment and avoiding other network constraints – both now and in the future
3. Ensure that creating additional capacity for LCT uptake does not adversely impact existing network reliability.

Each of these elements of our policy and approach is described further below.

#### Compliance with industry security planning standards

We have a licence condition to plan our electricity distribution in a way that provides an acceptable level of security of supply. Primary consideration is compliance with security planning standard P2. The P2 planning standard defines the level of spare capacity ('redundancy') that must be provided at each level of the network and for increasing groups of load. The network planning standard aims to provide electricity supply reliability commensurate the with the amount (MW) of group demand or generation. P2 thus influences the number of discrete circuits or transformer units needed to supply communities and neighbourhoods. Load-related expenditure improves our network resilience and minimises the frequency and duration of outages our customers experience.

Compliance with P2 security planning standard is a key driver of our investment proposals at EHV where it is usual to duplicate network components to ensure group demand can be supplied during fault conditions (forced outages).

In addition, it is a licence obligation that we comply with other industry codes and engineering recommendations in our overall design, such as G99 and G100 for embedded generators, which may impact specific load related works. Safety is also of paramount importance and there is an ongoing requirement for compliance with several statutory instruments and regulations, such as the Electricity Safety, Quality and Continuity (ESQCR) Regulations 2002.

*Security planning standards in SHEPD*

The geographical characteristics of our SHEPD network means that meeting the GB-wide security of supply standards can be costly and uneconomic for our customers in the North of Scotland. In some such cases an agreed and approved 'alternative planning standard' has been applied[30]. Within this ED2 business plan we have proposed to address (EREC P2) compliance issues at nine Primary substations classified as *exempt* in accordance with this alternative standard.

We are also investigating an innovative solution[31] to increase security of supply in areas where traditional reinforcement, or use of DNO owned standby generation to provide network resilience, is prohibitively costly. If successful, this concept could provide alternative, economic, and sustainable options to address network security in SHEPD.

### Invest in local network capacity sufficiently to meet future needs of customers

Whilst our policy and approach at EHV is significantly driven by compliance with deterministic security planning standards as peak demand is forecast to increase, at the lower voltages, especially LV, our proposed baseline investment is driven by the need to supply an increased level of demand associated with the connection of EV charge points to support 1.3m EVs, and 800,000 heat pumps in our licence areas by the end of ED2.

Whereas much of the investment at EHV aims to ensure continuity of supply to large groups of customers in the case of a fault on the EHV network, the investment at the lower voltages is to ensure sufficient local capacity to enable connections for EV, heat pumps and other types of LCT to be made in the first place. Failure to invest in local capacity risks a failure to deliver on our key strategic objective to facilitate accelerated progress to net zero.

### Ensure that creating additional network capacity does not adversely impact existing reliability

Our customers and stakeholders tell us that they value reliability of electricity supply highly, but only where this is delivered for a reasonable price and where it represents value-for-money.

The reliability of supply experienced by our connected customers depends not only on the resilience of the network and its ability to withstand the environment, but also in the ability and capacity of our business to respond and repair when things go wrong. It's of the utmost importance that the level of service and reliability received by our existing customers is not compromised or adversely impacted by the reinforcement and augmentation of our distribution system needed to support the uptake in LCT.

Against these three principles, the network is appraised, with a distinction in methodology between EHV and the HV and LV voltage levels.

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30 Ofgem has previously granted exemption from P2 compliance for specific sites on the basis of conventional reinforcement options being uneconomic. Sites which remain non-compliant with P2 will be subject to either a technical derogation request for a time-limited period or a CBA that demonstrates providing additional system security is uneconomic. The alternative planning standard is set out in PO-PS-037.

31 Resilience as a Service (RaaS) innovation project (RAAS | SSEN Innovation (ssen-innovation.co.uk)

## 6.3.2 Finding the constraints in the Primary Network

In SEPD (South) our Primary Network includes those operating at 132kV and 33kV. In the North, the Primary, or 'EHV', network comprises only 33kV, as 132kV is a transmission voltage in the SHEPD licence area.

The methodology used to identify EHV load-related expenditure is consistent across both licence areas although data has been obtained from separate, network specific, DFES projections. Our process combines existing network models used for producing the Long-Term Development Statement (LTDS) submission, contracted connections and associated reinforcement data, and the demand and generation projections from the DFES. This data allows us to replicate the scenarios of the DFES and our modified baseline scenario within a system model for each year of the ED2 price control. At EHV we have undertaken comprehensive load-flow modelling to assess the prospect of future network security 'non-compliances' – based on the range of input scenarios set out above.

Using power system analysis software, we have assessed our system for the ED2 period using the following:

- **thermal assessment** – to identify any assets which are at risk of thermal overload due to the increase in demand and/or generation. Thermal overloading can decrease the expected lifetime of an asset, trip system protection leading to customer outages and increase the likelihood of asset failure if overloaded for a prolonged period.

- **voltage assessment** – to identify any areas of the network which may experience high or low voltage beyond statutory limits. This can be caused by the increase in demand and/or generation. High voltages can result in damage to equipment and can trip system protection leading to customer outages. Low voltage can also cause damage to motorised appliances and will increase losses on the system.

- **fault level assessment** –to identify any areas of the network where the fault level exceeds 95% of the rating of system protection due to the increase in demand and/or generation. If a fault occurs and the fault level exceeds the interrupting current rating of the connected switchgear, this may cause severe damage to assets and more importantly risk the safety of anyone around these assets at the time of fault. This assessment has been run at worst case (maximum demand/maximum generation) and any fault levels identified to be more than the switchgear rating has been considered for reinforcement.

These assessments have been undertaken for *normal* operating arrangements and all credible first and second outage conditions where required, highlighting the system constraints and limitations by year, season and scenario.

## 6.3.3 Finding the constraints in the Secondary Network.

### Automated connectivity and rating analysis

A key issue to overcome in evaluating the investment needs of our lower voltage network is the vast number of assets involved (which is in the order of hundreds of thousands units/kilometres). This issue is

compounded by the lack of historical measurement in the LV network, and uncertainty in the precise connectivity of the assets in many cases.

Connectivity describes the actual physical structure of the network - which transformers connect to which feeders, and which feeders serve which customers. This is critical to creating an accurate forecast of the loading each component experiences and to understand a transformer's loading patterns, particularly its peak load, an idea of how many customers it's serving is required, which necessitates knowledge about the route of the feeder.

Figure 15 shows our machine-learning process used to better understand these connections. Note that the development and finalization of this model is an ongoing activity, which is further detailed in ***IT and Digitalisation (Chapter 05) and our Network Visibility Strategy (Annex 11.1)***.

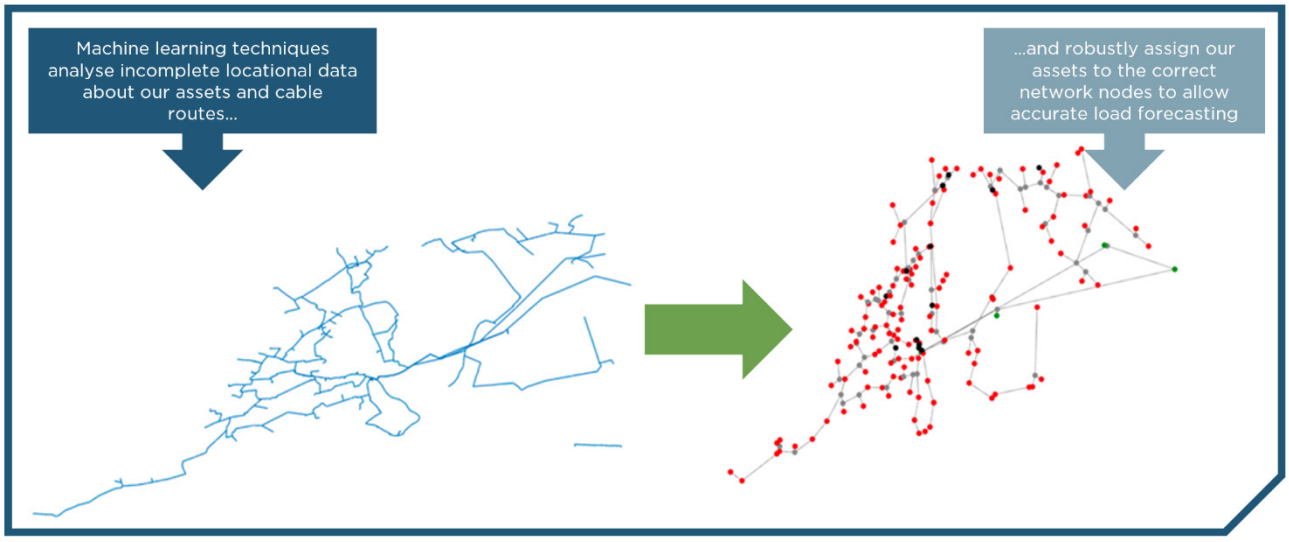


Figure 15- Representation of process for connectivity modelling.

All of these issues have been tackled through our ED2 Load Model project, which cleansed, repaired and leveraged existing data from multiple sources to create a clear and robust picture of the most likely connectivity and rating of every network component using a range of advanced data analytics approaches including machine learning and geospatial outlier detection. This complete, validated, view of our network has allowed the peak demand forecasts previously discussed to be applied to uncover the constraints throughout our lower voltage levels.

## Determining constraints from demands

With the baseline load calculated as described, we have added the granular forecast demand drawn from the DFES work described in Section 6.2. This additional demand has been built up from the component demands allocated to each individual LV feeder. Through comparison of forecast loading to nameplate circuit capacities, we have identified a hotspot list of 300 HV circuits with potential risk of thermal overload in the ED2 period. We have modelled these on power flow analysis software to assess thermal, voltage and fault level, in a similar manner to the EHV assessments as described in the preceding section on finding constraints in the primary network. We found approximately 345km of HV circuit that requires investment.

For secondary transformers and LV feeders, we have been able to identify future thermal constraints, by comparing the modelled nodal demand to the nameplate capacity of the assets serving that node. Where the forecast load exceeds 120% of nameplate rating for outdoor ground or pole mounted transformers; and 110% of nameplate rating for indoor ground mounted transformers. The total number of secondary transformers requiring investment by the end of ED2 is 5,646 in SEPD and 3,767 in SHEPD. The total number of LV feeders requiring investment by the end of ED2 is 3,008 in SEPD and 1,229 in SHEPD.

### 6.3.4 Constraints by Scenario

The first-pass assessment and subsequent categorization has allowed us to identify and prioritize constraints on our network before considering options to address each of these, as shown in Figure 16.

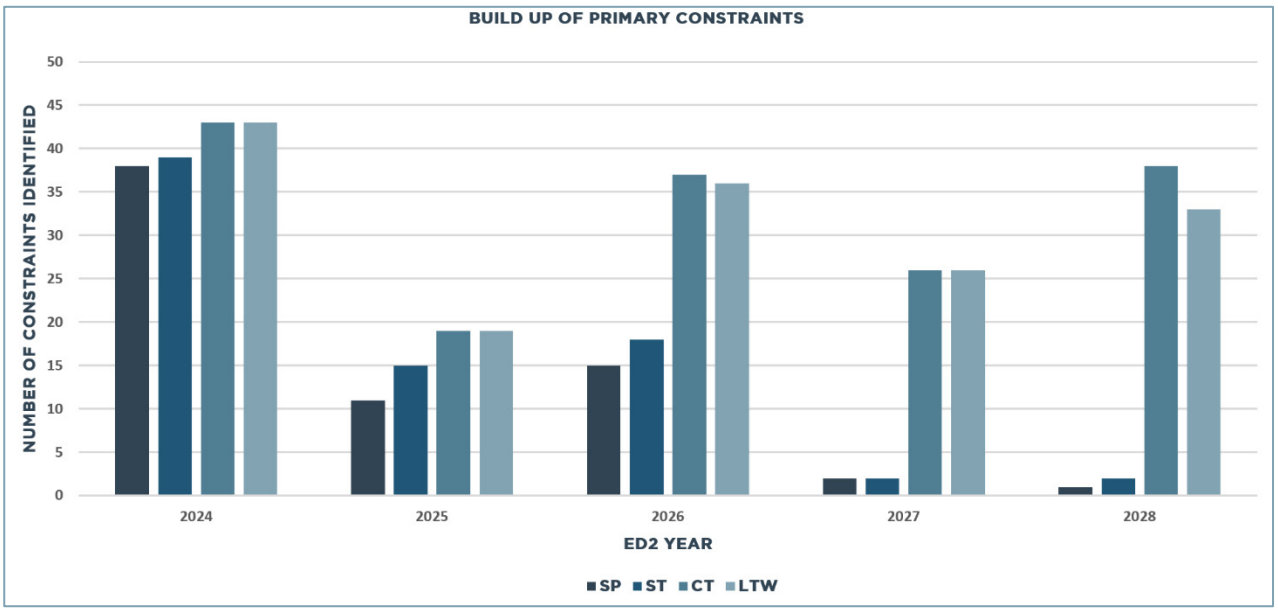


Figure 16- Build-up of primary constraints against different scenarios

Primary constraints identified include 163 thermal, voltage and fault level issues on our primary network based on assessment of our baseline scenario. To allow our plan to adequately factor in the uncertainty in our plan, we have also studied how these needs vary if a different scenario outturns, analysing Steady Progression (SP), System Transformation (ST), and Leading the Way (LTW) scenarios to gauge how wide a range of requirements could be present. Within the ED2 period, SP requires 43% fewer interventions through this assessment, reflecting the slower rate of LCT uptake in that scenario, manifesting significantly in 2027 and 2028, where CT and LTW scenarios drive many more issues than found in SP or ST due to the much-accelerated uptake of LCTs. Investigation of the scenarios shows that SP and ST do reach the same levels of LCT penetration as are present in CT 2028, but well into the 2030s- it is therefore anticipated that should those scenarios outturn, the same constraints would eventually require intervention, but potentially at a later time[32].

For the secondary network, our assessment also found a step change between the two more aggressive scenarios, LTW and CT, then in the case of SP and ST; again LCT uptake is the critical factor, driving the need to intervene on a very significant quantity of network.

[32] More detail on our post-2030 analysis is provided in Section 6.4.8.

Across HV and LV, and transformers, overhead line and cable, significant probability of overloading occurring was revealed if demand growth follows the CT or LTW scenario projections. LCTs being integrated in domestic settings, and therefore acting directly upon LV feeders, will challenge many LV cable routes contributing to the circuit lengths and transformer volumes shown in Figure 17 and Figure 18 respectively.

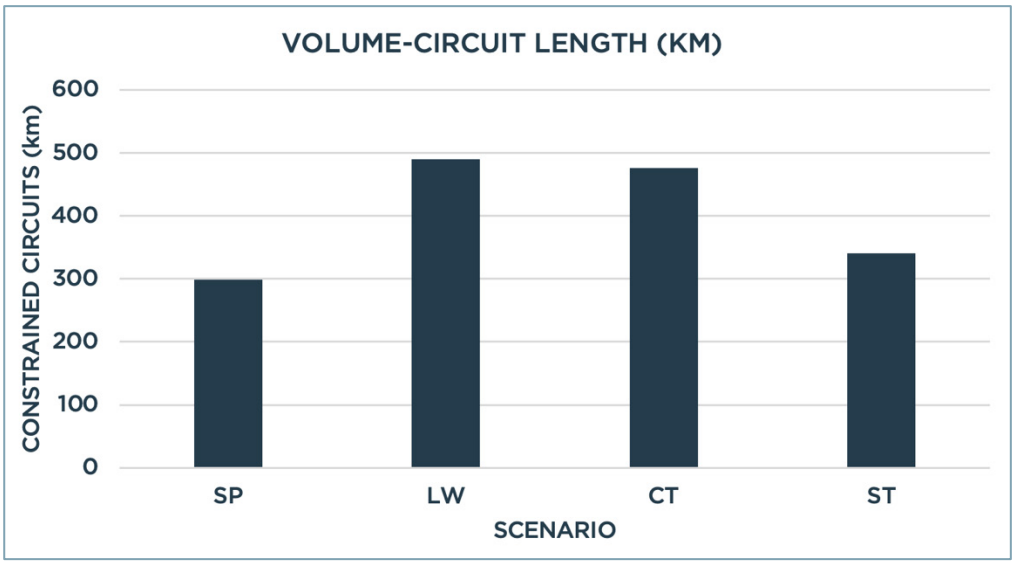


Figure 17 - Total circuit length (OHL and cable at HV and LV) requiring some intervention

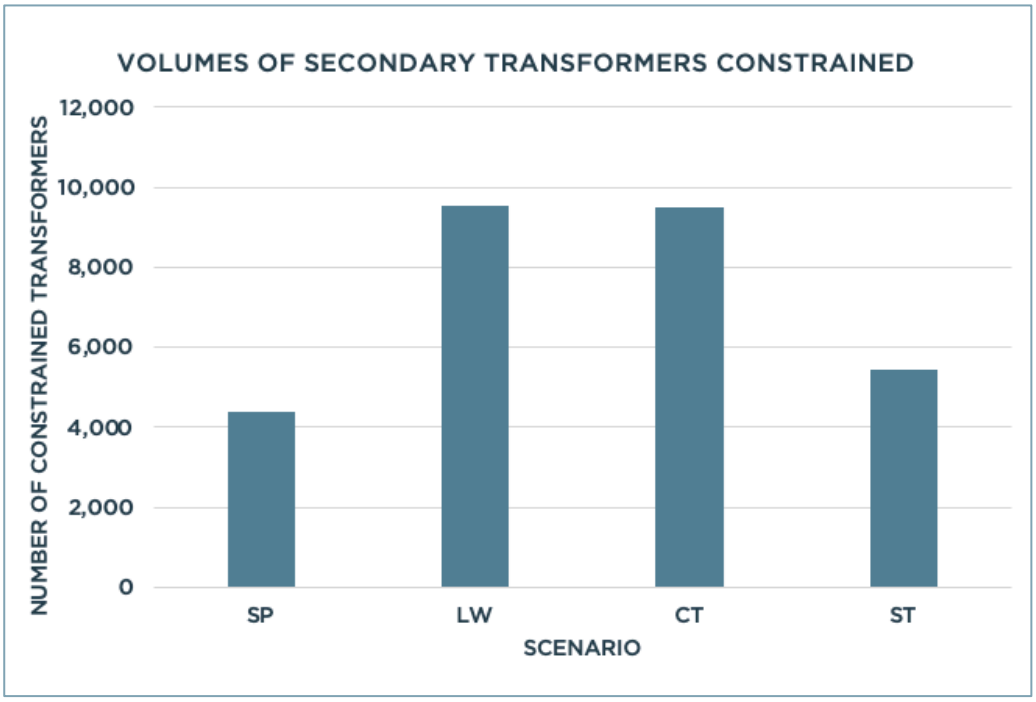


Figure 18- Total number of transformers on the secondary network requiring some intervention

## 6.3.5 Monetised impact by scenario

The identified constraints associated with the different scenarios have been used to assess the potential expenditure needed for each pathway. This was done before significant optioneering. For each constraint identified, the most likely conventional intervention, based on historical deployment, was selected. Typically, this follows a comparatively straightforward asset upgrade strategy. This 'first-pass' process leads to the cost estimates shown in Figure 19. As would be expected, the two pathways with accelerated LCT uptake require much more expenditure within the ED2 period to ensure sufficient network capacity and facilitate an increased number of new connections and connection service upgrades. The need is considerably lower for SP and ST for the same period, but still exceeds £300m for load related expenditure[33].

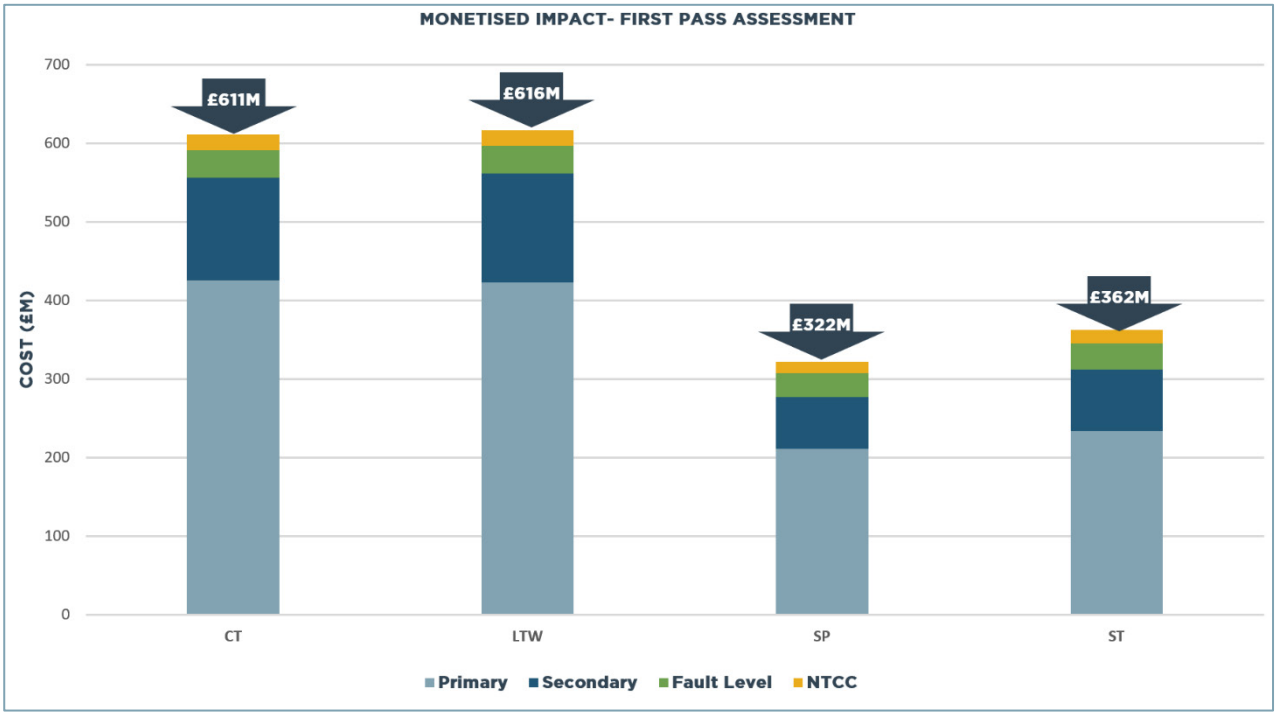


Figure 19- Monetised impact of conventional approach to addressing identified constraints

While these figures are pre-optioneering, they still represent a credible set of costs to address the volume of issues that could arise on our networks; this is why the engineering assessments and subsequent optioneering are so critical to generating consumer value by outperforming these preliminary set of solutions.

## 6.3.6 Generating intervention options

For the constraints anticipated across each voltage level studied, and for each credible future pathway, we have identified options for providing the capacity shortfall. In addition to conventional solutions (such as asset-based reinforcement), we have ensured that both flexibility and innovation have been prioritised in the assessment and justification process.

33 Excludes connection-related reinforcement costs, triggered by new or additional customer load.

- **Flexibility first:** the application of a flexible solution is considered for all constraints identified on our EHV system[34], as part of our broader actions on implementation of Whole Systems thinking[35]. On our lower voltage networks, our load-related expenditure proposals take full account of a range of different sources of flexibility[36].

- **Leverage ED1 Innovations:** we have sought to use technologies and solutions that have been successfully piloted during ED1 to ensure benefits for consumers are fully realized[37]

To provide a baseline for comparison, all technical assessments include a 'do minimum' option. This usually represents the lowest-cost conventional solution to ensure compliance with the required engineering standard (e.g. P2/7).

The following options are considered for each intervention requirement wherever practicable:

- Flexible solutions that allow the deferral of any other solution are always considered
- Conventional asset reinforcement to provide an increase in capacity - i.e. replacement of an asset with one of larger capacity
- Installing additional conventional assets, such as adding a parallel circuit
- Reconfiguration of the network (often in combination with asset replacement or addition)- for fault level issues, for example, splitting busbars to reduce fault level
- Whole system solutions, such as meeting distribution network needs through works on the transmission network
- Innovative solutions, including those deployed in ED1

- Flexible solutions that allow the deferral of any other solution were always considered

All selected solutions have been cross-checked against our other intervention plans to ensure coordination with no double-counting of solution expenditure (e.g. load-related and non-load related). More detail on these solution types are provided in the following sections.

### Adopting a Whole Systems approach to network needs

Our ED2 Whole Systems approach reflects our plan to embed a more collaborative approach to delivering customer benefit and value. We aim to achieve this through three main sets of actions, as set out below.

- Reflecting on progress and lessons learned - including assigning internal accountability for Whole Systems and adopting a more regional approach to working with local authorities;
- Reviewing internal processes to embed and promote Whole Systems thinking, such as working with SHET to review Whole Systems solutions and promoting Whole Systems thinking through increased reporting of initiatives; and

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34 The flexibility option is detailed on a case-by-case basis within individual EJPs.

35 Whole Systems (Annex 12.1)

36 Including domestic smart EV charging, domestic vehicle-to-grid; flexible heat from domestic heat pumps; the expected uptake in time-of-use tariffs, and a variety of energy efficiency interventions. A full and detailed account of our methodology for assessing the benefits of flexibility at HV and LV is provided in our DSO Strategy, Annex 11.1, Appendix G 'HV and LV Flexibility Methodology'

37 Further details can be found in our Innovation Annex, 14.1

- Embedding Whole Systems thinking into decision making including by producing and implementing guidance on how and when to use the ENA Whole Systems CBA.

There are two principal manifestations of Whole Systems thinking in our load-related activities; working with electricity transmission networks to apply a flexible approach to the use of capacity, including at the transmission-distribution interface; and procuring flexibility from market participants who may in turn support the development of flexibility from a wide range of sectors[38].

## Applying the Flexibility First principle

We have now adapted our standard processes for optioneering to incorporate a more proactive approach to procuring flexible solutions; extending the use of flexibility to our entire network - ahead of need - to existing (or potential new) flexibility providers across our entire network area. This allows us to better assess the opportunities to purchase flexibility and to respond more quickly as and when the need for a flexible solution arises. The location of all EHV network congestion (constraints) is visible to stakeholders on an independent marketplace for buying and selling smart grid flexibility services. We continue to encourage potential flexibility providers to register for details of future opportunities.

Figure 20 shows the types of flexibility services procured to date for our EHV system and the associated benefits and outcomes. These existing procurement exercises form the basis of our £150/MW/hour availability cost assumption, and £150/MWh utilisation cost used for assessment of alternative solutions on our EHV system[39].

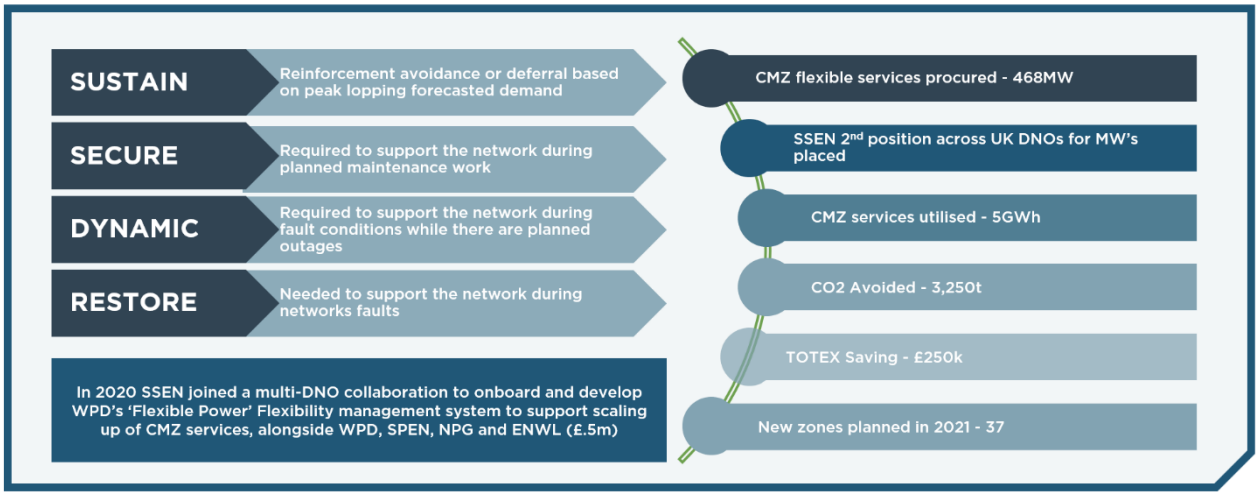


Figure 20- Structure of Flexibility services procured

The network constraints identified through the first-pass assessment form the basis of our 'Global Call for Flexibility'[40]. The purpose of this work is to inform and obtain flexibility interests and potential flexibility prices from service providers. An important first step is our request for 'registration of interest' for flexibility. This is undertaken ahead of formal procurement for flexibility and allows us to accommodate the uncertainty associated with scheme delivery each year.

38 We provide further details on our ED2 transition pathway in our paper Whole Systems (Annex 12.1).

39 Details on our approach to flexibility on our HV and LV systems is provided in Section 6.4.1.

40 https://www.ssen.co.uk/ConnectionsInformation/GenerationAndStorage/FlexibleConnections/CurrentCallsForFlexibility/.

We will be undertaking formal engagement with the flexibility market during the ED2 period as part of our business-as-usual investment decision-making process. Our work in this arena allows us to credibly assess and compare flexibility options for inclusion in our baseline plan.

### Working with Transmission companies

We have worked closely with our Transmission partners including National Grid Electricity Transmission, Scottish Hydro Electricity Transmission and National Grid Electricity System Operator on our load-related plan. Their invaluable feedback has helped us improve the intervention options for a number of load-related schemes.

A typical example is the collaboration with our partners on the Fleet-Bramley 132kV network to manage the demand group growing beyond Class E (1500 MW). We also worked closely with the Transmission Operators to align the load forecasts at the T-D interface the results from which form our Transmission Connection Point Charges for ED2[41].

### ED1 Innovations

There are several key innovation projects and learnings on which we have drawn in the preparation of our load-related expenditure, including those shown in Table 22. Transferring value and benefits from innovation projects and initiatives into our business-as-usual investment decision-making continues to be high priority for the remainder of ED1 and into ED2 and beyond.

The innovations most relevant to our load-related expenditure proposals are associated with the procurement and use of flexibility and monitoring of LV circuits to better understand potential overloads and help refine and improve forecasts and projections. The list of innovations is provided in Table 22, where we also set out the customer benefit and provide a link to more detail of specific innovation initiatives.

Table 22 - Innovation which has influenced our load-related expenditure proposal

| Business Plan Area | Innovation topic | Proposed ED2 Deployment | Customer benefit |
|---|---|---|---|
| Load Related | LV Monitoring | Widespread deployment proposed for ED2 – between 17k-22k deployments at a cost of up to £28m | Details in the LV Monitoring EJP |
| Non Load & Load | On Load Tap Changers at lower system voltages | This technology has been successfully deployed by ENWL in the Smart Street Project. The equipment dynamically manages voltage to the optimum level. Circa 435 deployments | Brings benefits to customers connected to the LV networks via reduced bills, associated losses reduction and potential headroom improvements |

41 Further details can be found in our Whole Systems, Annex 12.1

| Business Plan Area | Innovation topic | Proposed ED2 Deployment | Customer benefit |
|---|---|---|---|
| Load | LV Meshing | There are several options available to 'mesh' LV networks – these are solutions which can be applied in specific circumstances to provide additional LV capacity. | Additional Headroom / capacity on LV networks. |

## Conventional solutions

An important principle of CBA is that all credible options are compared. Conventional solutions also provide multiple potential ways of addressing network constraints, in line with historical network planning activities. Alternative approaches may consider replacement with a higher rated asset, or adding new assets alongside existing ones, different configurations at substations. For each constraint all credible conventional options have been fully considered in the optioneering process, these are documented in our IDPs.

## Planning for net zero – sizing conventional network capacity

For the conventional solution options, a critical consideration is the correct sizing of any replacements or additions; this additional capacity creates the headroom needed for future demand growth. In undertaking this capacity sizing exercise, and determining the appropriate capacity to install, we have taken full account of the range of credible post 2030 net zero pathways.

For Primary (EHV) system assets, the appropriate asset capacity has been considered on a case-by-case basis, taking full account of post ED2 load projections.

For Secondary transformers (11kV/LV), a standard approach is applied, again based on post ED2 load projections. The replacement asset rating has been based on aiming for the utilisation of the new asset to be no more than 60% loaded (with respect to nameplate capacity) under peak conditions at the end of ED2. Analysis of the CT scenario in 2050 has shown that in many cases this approach will ensure that the asset is adequate for our baseline view of the network requirement at 2050. This minimises the probability of the need for further work to upgrade the asset to enable net zero.

In some cases, we may need an alternative solution type – for instance moving from an HV/LV pole-mounted to a ground-mounted substation, because a pole-mounted substation solution has a maximum practical capacity, for example. Where a single ground-mounted substation solution can no longer provide increased capacity required then increased levels of circuit interconnection, or an additional ground-mounted substation, may be required.

Changes to the solution type normally has significant cost implications, so to mitigate this, if the largest capacity solution of the same type would still provide sufficient capacity (i.e. would be less than 100% loaded) in 2050, we have accepted with as a replacement solution even if the projected load at the end of ED2 breaches the 60% maximum rule.

If the new asset would not be able to sustain 2050 flows, then the proposed solution is to deploy LV measurement and flexibility solutions to ensure we do not unnecessarily incur the significant expense of changing solution type.

For HV and LV feeders, we take the simpler approach of selecting the maximum size cable or overhead line conductor that does not incur significant additional expense. For instance, overhead line routes may be constructed with a conductor of larger diameter, but at a particular threshold of conductor size work will be required on the poles and structures, significantly changing the economics of the approach. This is a low-cost method of maximizing our network headroom to ensure net zero readiness. We have assumed maximum-sized cable will be used to replace all first sections out from distribution substations (11kV/LV) – this includes from pole-mounted substations where the LV overhead line is overloaded.

### Options already considered for other drivers

The options generated have been tested against the planned non-load interventions from other parts of our plan. For example, the same asset requiring intervention to provide additional capacity may also have been identified for intervention due to its condition, or due to environmental factors such as associated $SF_6$. To ensure no double-counting, work has been undertaken to ensure that interventions having different key drivers have only been captured once in the expenditure portfolio and the business plan data tables.

### Summary of prevalence of considered options in EJPs

Table 23 summarises how often each solution type feature in the underlying analysis. Flexibility has been actively considered as a solution in the majority of cases. It should be noted that whilst flexibility is a valid option for addressing thermal constraints, it is usually not a viable technical nor economic option for resolving fault level constraints.

Table 23 shows that asset replacement is the dominant solution, as the simplest solution which can apply to most requirements; however, the cheaper network reconfiguration option was considered in a large number of cases, particularly for fault level at substations where busbar splitting can be an economic solution. In many cases, however, the forecast increase in demand requires the installation of additional assets to provide sufficient network capacity and to ensure compliance with network security planning standards. Innovative solutions include dynamic rating of assets, application of fault level reactors, network meshing (see Table 22).

Table 23 – Prevalence of solution types.

| Solution type | Share of EJPs in which solution type is actively considered |
|---|---|
| Replacement of assets | 87% |
| Flexibility | 100% |
| Network reconfiguration | 56% |
| Addition of assets | 27% |
| Innovative solutions | 25% |

## Low Voltage Service Upgrades to Support LCT

Supporting the transition to net zero and ensuring that we are never a barrier to the uptake of LCT means that we need to not only need to respond to network capacity needs identified through customer connection applications, but also work to pro-activity remove any network constraints or capacity 'bottle-necks' that may otherwise prevent the connection of EVs and heat-pumps. This pro-active work includes work to remove and upgrade looped services – which we consider to be the biggest barrier to customer adoption of LCT in terms of the potential delay in connection, as a result of the required remedial work.

We anticipate having to carry-out 13,000 schemes across both licence areas (3,000 SHEPD, 10,000 SEPD) in ED2 to upgrade (de-loop) looped services in response to customer LCT connection requests. This represents our reactive investment for de-looping and associated works, which includes fuse upgrades, extension asset works and broader reinforcement work. Our LV service upgrade strategy is based on the premise that any broader additional reinforcement costs associated with customers wanting to connect EV chargers and heat pumps should be shared amongst all our customers.

Our proactive investment for these works is based on the aim of ensuring that customers who want to connect an EV or heat pump have an 'LCT-ready' network available to them. Our proposal is based on identifying and targeting LV services that need upgrading and to undertake the required work ahead of individual customer need. For example, where a single customer connection enquiry or notification leads to service upgrade, this may signal the opportunity for efficient upgrade to multiple LV services in the same street or village in preparation for other new EV connections in the same locality.

This approach will allow us to establish dedicated teams and to build a programme of upgrades with the same number of jobs per week made up of both reactive and proactive jobs, ensuring a predictable workload over the ED2 period, thereby enabling unit cost delivery efficiencies and fulfilling customer needs and expectations.

Based on our estimate of average costs, this will require an expenditure of [redacted] across SSEN in ED2 for proactive replacement works, with a total of 625 schemes for SHEPD at a cost of [redacted], and 2,000 schemes for SEPD at a total cost of [redacted].

Our prioritisation of location for proactive investment will continually improve through advancements being made in our internal data and analytics capability relating to LCT uptake and asset constraints, along with innovation projects being delivered in ED2, such as Skyline[42].

It is antipated that cost of proactive LV service upgrades will be funded through an appropriately designed and implemented uncertainty mechanism. There is no provision made for this expenditure in our ex-ante baseline funding request.

[42] The Skyline project seeks to establish data-sharing agreements with organisations involved in the sale and lease of EVs and HPs such that customer information (GDPR compliant) is shared with SSEN at the time queries and made and orders raised. This allows assessment of properties and networks to be carried out proactively before the LCTs are due to be installed, thereby supporting planning of the proactive LV service upgrade work.

## 6.4 OPTIONEERING FOR AN EFFICIENT PLAN

In the previous sections, we set out how we have identified the load-related requirements of our network against a range of potential futures, and our approach to generating multiple potential solutions. The next step is the selection of a combination of solutions to deliver an overall package of interventions. This selection must meet criteria from our licence conditions, and industry regulations, and also satisfy the needs and priorities we have co-created with our stakeholders. In developing solution options, we consider the following:

- compliance with all relevant technical rules associated with our licence and other established and mandated industry standards
- selection of a solution option that deliver the outcomes stakeholders want for a reasonable cost; must be economic and efficient
- consider flexibility first wherever practicable
- stakeholder outcomes must be carefully assessed, quantified and compared to enable demonstration of trade-offs between different intervention options

This section outlines how we have analysed the options to meet the above criteria.

### 6.4.1 Scope of assessments

For all schemes of more than £2m in value, a CBA has been undertaken alongside an EJP. The project cost threshold uses for determining the need for a CBA has been set according to Ofgem guidance and aims to manage the volume of analysis conducted and reviewed, whilst ensuring that all impactful decision points are treated in the most rigorous way possible.

Due to the high-volume nature of HV and LV networks, the constrained assets have been grouped into three types: HV feeders, secondary transformers (HV/LV) and LV feeders. A single EJP has been produced for each of these generic scheme types for the purpose of the business plan. The design and delivery of these reinforcements considers the non-load related investment portfolio to optimise efficiencies and reduce customer outages.

CBA is a key tool for building efficiency into our plan; it demonstrates that multiple options have been considered, and that the selected option delivers maximum value for consumers. Our CBA uses the standard template and guidance for RIIO ED2 as published by Ofgem; this tool monetizes relevant benefits, nets them against investment costs, and appropriately amortizes and discounts the cost and benefit streams to arrive at a Net Present Value (NPV) of each solution.

The highest NPV solution will normally be selected; however, if multiple options are very close in value, and there is an engineering reason to deviate from the optimal NPV which is not readily captured by the CBA approach, another option may be selected. Where this has occurred, the justification is detailed in the relevant EJP.

The inclusion of flexibility solutions as an option to meet many of our requirements has necessitated the introduction of an additional appraisal tool: the ENA Common Evaluation Methodology (CEM). This CEM tool enables like-for-like comparison of between the optimal conventional (constructed) solution with a flexibility solution – such as contracting with third parties to alleviate local network constraints and hence defer investment.

## 6.4.2 Tools and models used

For the purpose of investment justification, two standard industry tools have been used to ensure a consistent approach and alignment of our submission with other DNOs. The use of standard tools also provides confidence that the underlying economic assumptions are reasonable and robust.

We use two models when assessing use of flexibility in our plan. We firstly assess all conventional (constructed) solutions using the standard ED2 CBA template. The most economic conventional solution is identified and then compared to a flexibility option using the CEM model, which is used to capture and assess the potential value generated from flexibility. This process is shown in Figure 21.

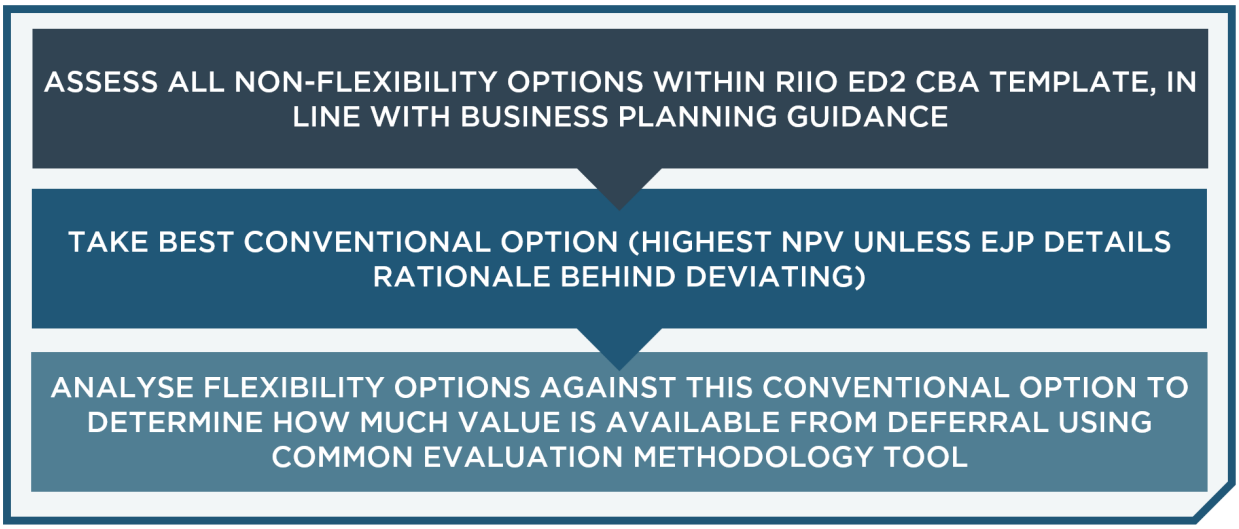


Figure 21- Hybrid CBA-CEM approach to compare flexibility to conventional solutions

### The Ofgem CBA model and CEM tool

In developing our load-related expenditure proposal we have used the CBA model published by Ofgem. Supporting documentation that defines how the model should be used, is also published.[43]. We have supported industry development of the final model and guidance and have followed this in the CBA required for our load-related business plan.

The CEM tool is a standard approach to making decisions about the use of flexibility to defer capital expenditure[44]. Full guidance on the tool and how it calculates benefits is available at the ENA website[45].

43 https://www.ofgem.gov.uk/system/files/docs/2021/04/riio-ed2_cba_guidance.pdf
44 The development of the CEM was led by the Energy Networks Association (ENA).
45 https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology-PUBLISHED.23.12.20.pdf

### Scope of the Common Evaluation Methodology (CEM)

**A common methodology for DNOs to assess flexibility options to meet network need**

- Created primarily to evaluate deferral of conventional (constructed) reinforcement by purchasing flexibility. The tool can be used to evaluate a range of non-flexible options, energy efficiency and Active Network Management solutions
- The CEM Tool is a Microsoft Excel model based upon the Ofgem ED1 CBA
- DNOs use the tool to evaluate the costs and benefits of the selected options
- Tool allows the user to test different flexibility strategies under various load scenarios eg DFES, FES etc
- It provides insights to enable the user to make the decision under uncertain load scenarios

## 6.4.3 Key CBA drivers and outputs

In this section some of the results from our CBAs are discussed, followed by an assessment of the net impact of our selections on the critical, non-monetised metrics of utilisation and load index (LI) index.

Across all ED2 investments, the key metrics within the CBA are consistent, aligning with the official ED2 CBA template. For Load-related CBAs, the impact on customer minutes lost (CML), customer interruptions (CI), and avoided costs have been the most relevant in identifying the option that delivers the most value for consumers.

Alongside these metrics, other key indicators include the monetised risk impact (where older assets replaced for load purposes can represent risk removed from the network) and the capacity released by our interventions. To avoid double-counting of benefits, we have ensured that these do not contribute to the NPV within the CBA template, although provides insight into the performance of the overall portfolio.

Both in terms of cost saving and network reliability, our analysis has shown interventions have long-lasting benefit. Our proposals help reduce related costs and also have a positive impact on CI and CML by reducing the overloading of network assets. Use of the CBA tool demonstrates the economic selection of solutions. And our optioneering process ensures all considered options are compliant with relevant codes and licence conditions.

Using the CBA tool, we have been able to undertake sensitivity testing on the timing of costs and benefits. We have found that NPV generally improves when projects are delayed (i.e. benefit of delaying cost is generally greater than the time value of accessing benefits sooner). This insight was coupled with the flexibility assessments to help determine our final phased investment profiles.

It is important to note that our CBAs do not capture all benefits. For example, if without intervention the network would be non-compliant, we do not consider not intervening and allowing non-compliances. We also do not attempt to monetize the benefit of being compliant, which does not affect the CBA as all options considered achieve this critical purpose.

### 6.4.4 Network utilisation analysis

Network utilisation is an important way of understanding how our network is performing for consumers. It is a measure of peak loading on assets. Low levels of network utilisation might suggest that the network can be used more efficiently, whereas high levels of network utilisation – even going beyond the nameplate rating – can indicate that the network not be able to meet demand, with overloads potentially causing faults, leading to poor levels of reliability.

Network utilisation, as a single metric, needs to be interpreted carefully in the context of distribution system planning and network design. Constraints on networks can be driven by other factors like fault level and voltage issues that mean circuits and substations may require additional capacity to remain compliant.

Additionally, the 'lumpy' nature of network investment and the uncertainty associated with LCT uptake may mean that it is prudent to add additional capacity earlier.

At the Primary network level, we have an established approach for determining and reporting LI forecasts. At the Secondary system level, to evaluate the utilisation of distribution transformers, we have developed a sophisticated model. The load model combines supplier derived data for individual properties with network level maximum demand measurements, half-hourly metering readings and higher-voltage SCADA measurements to establish DFES projections at a local level using machine learning techniques.

There is a complicated fabric of changing demand patterns (both increases and decreases) across our grid, primary and distribution transformers. In SEPD in 2020, 8% of our distribution transformers operated at 80% utilisation or more. By 2022, under forecast scenarios ST and CT, this increases to 9% and 11% respectively, and 14% and 22% in 2027 – without intervention.

In SHEPD, 6% of distribution transformers operate at 80% utilisation or more in 2020. This increases to 7% and 8% in 2022 under ST and CT respectively, and 10% and 17% in 2027 respectively.

Near-term forecasting is more challenging than forecasting over the mid-term, given the major macro-economic effects of recent times (including COVID-19 and Brexit). Each of the DFES scenarios clearly indicates the impact of decarbonisation throughout the ED2 period, however the precise point at which this becomes the dominant effect during the remaining years of ED1 is likely to be heavily influenced by other immediate economic and policy changes.

Moving into ED2 we expect demand to increase significantly due to the LCT uptake required to meet the UK and Scottish governments net zero targets. This is particularly so for our LV network. Accommodating this additional demand, along with existing baseline load, will create new challenges for ED2.

Taking a *flexibility first* approach will mean we can maximise existing capacity in the shorter term, where appropriate, to accommodate increases in distributed-connected generation at the lower voltages, and significant increases in low-voltage connected EVs and heat pumps. However, we expect there to be an increasing need for local reinforcement which is not reflected in demand measured at Grid Supply Points (GSP).

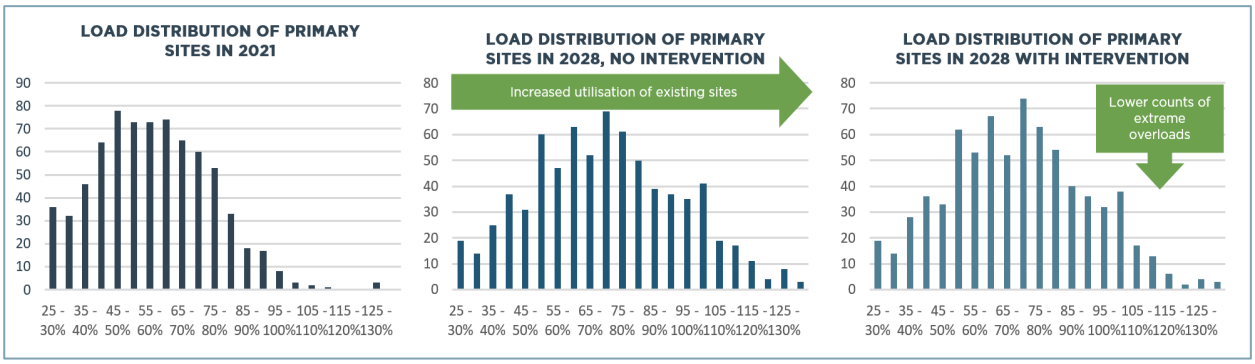


Figure 22- Load Index changes with and without ED2 intervention

Changes in load index with intervention is shown in Figure 22 and changes in utilisation are shown in Figure 23.

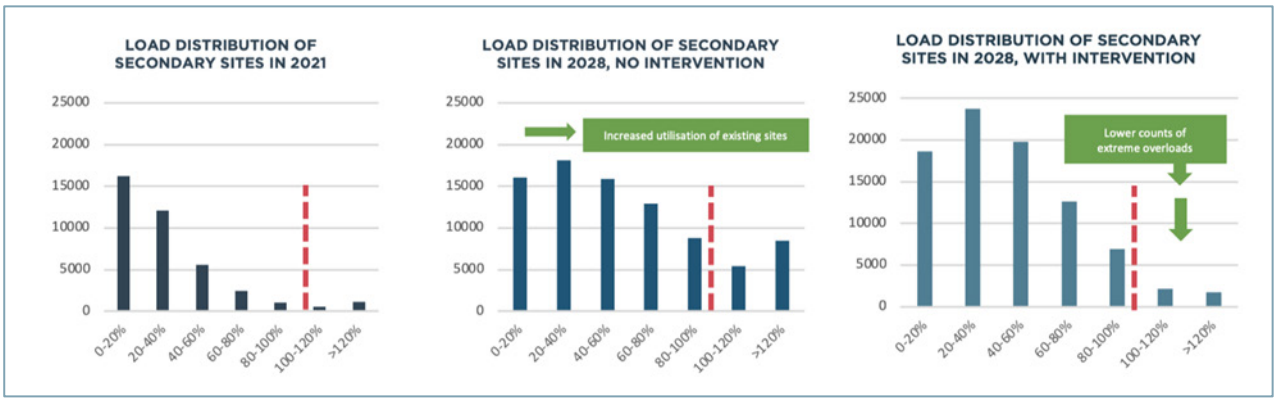


Figure 23- Utilisation changes with and without ED2 intervention

## 6.4.5 How we applied flexibility and timing of interventions

The year that each intervention is undertaken is an important consideration. The key factors considered are as follows:

- The year the network is forecast to become constrained or non-compliant without intervention
- The resource availability to undertake the work efficiently alongside all other activities the workforce is forecast to be undertaking
- The degree of uncertainty (delaying the work may improve demand forecasts and thereby enable better expenditure decision-making)

Identifying the optimum timing for intervention work follows a simple set of rules to ensure these factors can all be addressed. This will also determine associated work volumes attributed to each year of the ED2 period. The following rules have been applied.

1. Set the latest possible date of intervention to that when the constraint arises. The CEM tool will then provide information on the value of delaying a conventional constructed intervention using flexibility services. If flexibility is economical, the CEM model will determine when the flexibility service should commence and for how long (years) the flexible service must operate until a conventional constructed (asset) solution is required.
2. Consider a smoothing of activities over the ED2 period to ensure work can be efficiently resourced. This is done at a ED2 portfolio-level and with consideration of our forecast workforce (further details can be found in our Deliverability Strategy Annex, 16.1).
3. Where the opportunity exists, assess the NPV impact of delaying or advancing the work[46].

The impact of applying this process is reflected in the volumes of work shown in the submitted BPDT across the ED2 period. This is summarised in Figure 24.

## 6.4.6 Accounting for system flexibility

Flexibility services play a major role in our DSO Strategy[47]. Deploying flexibility services at LV and HV has numerous advantages. It can defer conventional reinforcement and avoid capital expenditure and deliver benefits for customers in terms of both lower costs and more feasible and assured delivery of the reinforcement programme. Flexibility at LV can significantly reduce the winter peak demand growth that is driven by the uptake of LCTs.

[46] In our CBAs, the NPV is improved in two schemes, Iver and Bramley, by hypothetically moving these forward- however they are already planned for the earliest credible delivery.

[47] DSO Strategy, Annex 11.1

Our methodology examines the potential reductions to winter peak demand from a variety of flexibility sources. At LV, our analysis includes five different sources of flexibility, including domestic smart EV charging, domestic vehicle-to-grid; flexible heat from domestic heat pumps; the expected uptake in time-of-use tariffs arising from Ofgem's Access and Charging Significant Code Review, and a variety of energy efficiency interventions. A full and detailed account of our methodology for assessing the benefits of flexibility at HV and LV is provided in our DSO Annex[48].

We reference a range of published studies such as SmartCar, Project Shift and those in our Energy Efficiency CVP. For LV we also take account of behavioral and technical diversity and participation rates. At HV our analysis examines generation, storage, and demand-side sources in each network area.

Flexibility produces a substantial reduction in the overall demand, and also in the utilisation of network assets. The demand growth (driven in turn by the growth in LCTs) is significantly slowed and the required reinforcement can be deferred. This saves costs for customers and improves deliverability by spreading out effort to reinforce the network.

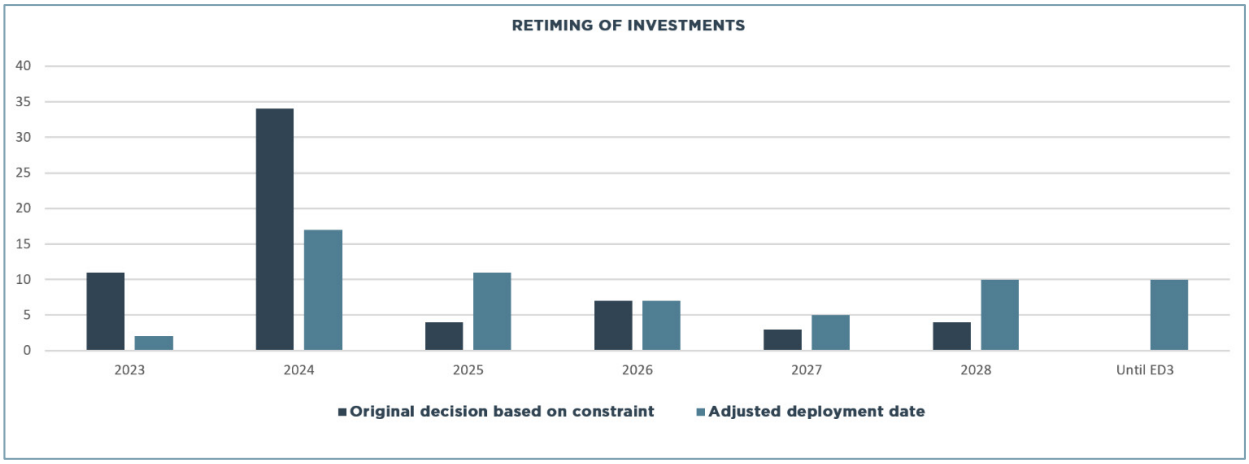


Figure 24 - Impact of timing decisions

The single biggest factor in our timing of decisions is the application of flexibility for deferral. Flexibility has been selected wherever the CEM tool demonstrates a robust case for so doing in the form of a positive NPV assessment[49]. This price is based on our market engagement to date and reflects a central view of the cost of flexibility service. Implementation of flexibility schemes will depend on market liquidity in the right network areas to affect and mitigate a constraint.

To show a range of credible outcomes in the use of flexibility, which will vary by the cost at which it is generally accessible, a sensitivity at different assumed prices has been performed and provided in Table 26.

As can be seen in Table 24, we have found significant scope for potential savings from deploying flexibility services. More details on our approach to the use of flexibility in ED2 can be found in our DSO Strategy[50].

48 Ibid., Appendix G 'HV and LV Flexibility Methodology'.

49 Assumes flexibility can be secured at a cost of £150/MW/hour for availability and £150/MWh for utilisation.

50 DSO Strategy, Annex 11.1, Appendix F Delivering Value Through Flexibility

Table 24- Use of flexibility for investment deferral in our load plan under Consumer Transformation

| Summary- application of flexibility in Load | |
|---|---|
| CAPEX deferred beyond ED2 | £15.2 – 41.9m |
| CAPEX deferral savings in ED2[51] | £3.1 – 4.4m |
| Cost of procuring flexibility services | £5.1 – 6.5m |
| Flex Capacity considered | 649 MVA |
| Flex Capacity used | 176 – 208 MVA |

## 6.4.7 Overall impact of optioneering

The first-pass assessment of our constraints, coupled with the application of efficient unit rates for a conventional way of resolving these constraint archetypes, generated a view of £611m of expenditure required to address all the network issues identified across both networks (excluding connections driven spend). This initial analysis was based on the CT scenario. Subsequent engineering analyses and optioneering reduced this initial cost assessment by 43%. This is shown in Figure 25.

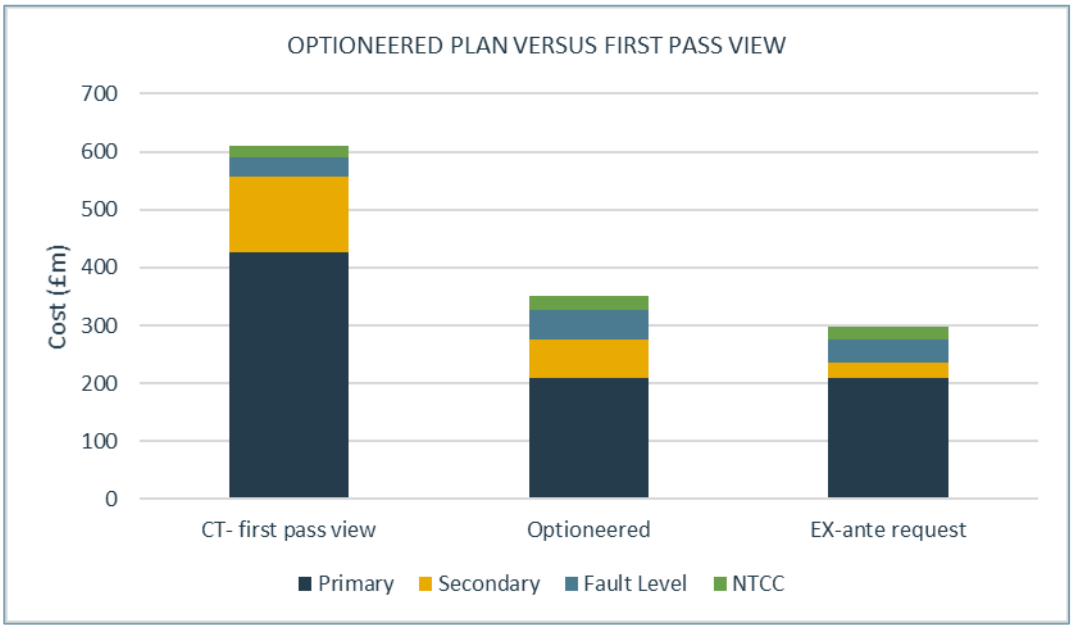


Figure 25- Monetised impact of optioneering

The three main sources of the reduction are described further below.

1. **Engineering analysis and detailed power system modelling** to refine the scope of work and optimise investment; identifying that in some cases only a subset of the affected components or lengths of circuit need intervention. In other instances, showing how attributing a dynamic rating to assets can ensure compliance without intervention.

[51] Direct savings, as defined in the ENA's Common Evaluation Methodology, come from the benefit of delaying investment, hence accessing the time value of money being deferred- less the cost of procuring the flexibility.

2. Through our ongoing work to determine ambitious trajectories for **unit cost reductions** associated with intervention activities; and
3. By realising efficiencies identified through our optioneering process, and the inclusion and assessment of a wide range of solution types including **flexibility, Whole Systems, ED1 innovations, network reconfigurations and conventional asset solutions**

### 6.4.8 Sensitivity analysis of optimal interventions

One key objective of our ED2 submission is to identify an investment strategy that is robust across different credible pathways to net zero. To ensure this is the case, we have studied network requirements across all DFES, and analysed our proposed interventions against these needs. We have categorised the relative certainty of each proposal, and the relative cost of each scenario in terms of required investment. This is shown in Figure 25.

We have also used sensitivity analysis to enhance our confidence in the robustness of the business plan. This type of analysis answers the question "what would we need to believe for the right option to pursue to be different to our baseline answer?". This question can be asked in the context of any of our input assumptions. To create a coherent and useful set of sensitivities, we have focused on assumptions we view as critical, as well as those suggested in the business plan guidance. Table 25 presents the sensitivities we have undertaken for load-related expenditure.

Table 25- Sensitivities on LRE undertaken

| Sensitivity No. | Name | Key parameter(s) | Description |
|---|---|---|---|
| 1. | Peak demand sensitivities (With CCC assumptions) | EV charging profiles, Heat pump usage profiles | Work to establish the plausible range of peak demands that could be experienced at LV feeder and secondary transformers. We have selected the worst and best credible cases of consumer behaviour for peak loadings on the LV network. This has enabled demonstration of how the optimum level of LV investment varies with demand profiles. |
| 2. | Would we make different decisions if we were making submissions for the post 2030 period? | Year studied | Our submission focuses on what we will do in the ED2 period. These decisions are made whilst considering what will happen post ED2; when intervening in our network, we factor in post 2030 network loading when sizing assets to ensure we minimize rework. We have also reviewed what we would do if we were making decisions for out to 2035 at this time; this tells us about how robust our plan is for 2023-2028, and how that set of interventions will flow into the 2030s where further requirements will arise. |
| 3. | Demand and anticipatory investment testing | Assumed demand | This exercise tests how much of our portfolio can be considered 'anticipatory', to understand how |

| Sensitivity No. | Name | Key parameter(s) | Description |
|---|---|---|---|
| | | | influential capex and demand are on our anticipatory measure. |
| 4. | How much flexibility is economic at different prices? | Availability and utilisation costs for deploying flexible solutions | Using the CEM template, we varied our key assumption around how much we might need to pay to secure flexibility to defer the need for asset investment. |

### Sensitivity 1: Peak demand variations

Forecasting of future peak demand at different points on our network has required comprehensive processing and modelling of the DFES. This process has required a number of assumptions to be made around how LCT demand might manifest at peak times and applying these assumptions to the uptake of different technologies forecast by the scenarios. These assumptions form the basis for thinking about peak demand sensitivities, as LCT peak demand behaviour in future years is subject to uncertainty due to uptake not being sufficiently widespread at present to be certain how consumers will use such technologies in future. Key examples of such assumptions and uncertainties include the following.

- **Smart charging of EVs:** The prevalence and consumer uptake of offerings where their charging is incentivised to occur at different times on the network, mitigating impact on peak demand. Specific offerings could even respond to specific network constraints, meaning EV flexibility could help defer network investment, rather than drive it. The extent to which these offerings are present and accepted could therefore significantly vary peak demand estimates at different points on our network.
- **Heat demand:** Whilst heating demand has lower inherent flexibility than EV demand, different levels of uptake of measures which improve the thermal efficiency of buildings, or applications of heating storage solutions could mean that installed heat pumps have different loading requirements in the future.
- **Technology clustering assumptions:** Our scenario work has included the allocation of technologies to specific points in our network, with our 'best view' of how uptake could progress geospatially; changes to the underlying assumptions could mean the impact of LCTs could appear more rapidly on single network nodes, with a higher rate of clustering, or conversely be more spread out in their initial impact meaning fewer overloads in early years of uptake.

These factors can all drive differences to the forecast peak demand at different nodes on the network, and hence increase or decrease investment needs from our base case. To gain understanding of the potential impact and ensure the envelope of uncertainty is something to which our base plan is robust, we tested higher and lower peak demands commensurate with the uncertainty present in our peak demand assumptions.

Figure 26 summarises the results of this testing, with the left-hand figure demonstrating a worst-case view on a low voltage asset, and the right hand figure showing a band of changes to our secondary asset investment requirements (illustrated by our base case, CT) driven by the most extreme but credible sensitivities tested. This range of cost changes foreseen illustrate the scale of the uncertainty in our needs within ED2, however we are confident that our baseline plan, coupled with uncertainty mechanisms and monitoring of how demand is changing through ED2, will enable us to respond efficiently and effectively to the range of potential future outcomes.

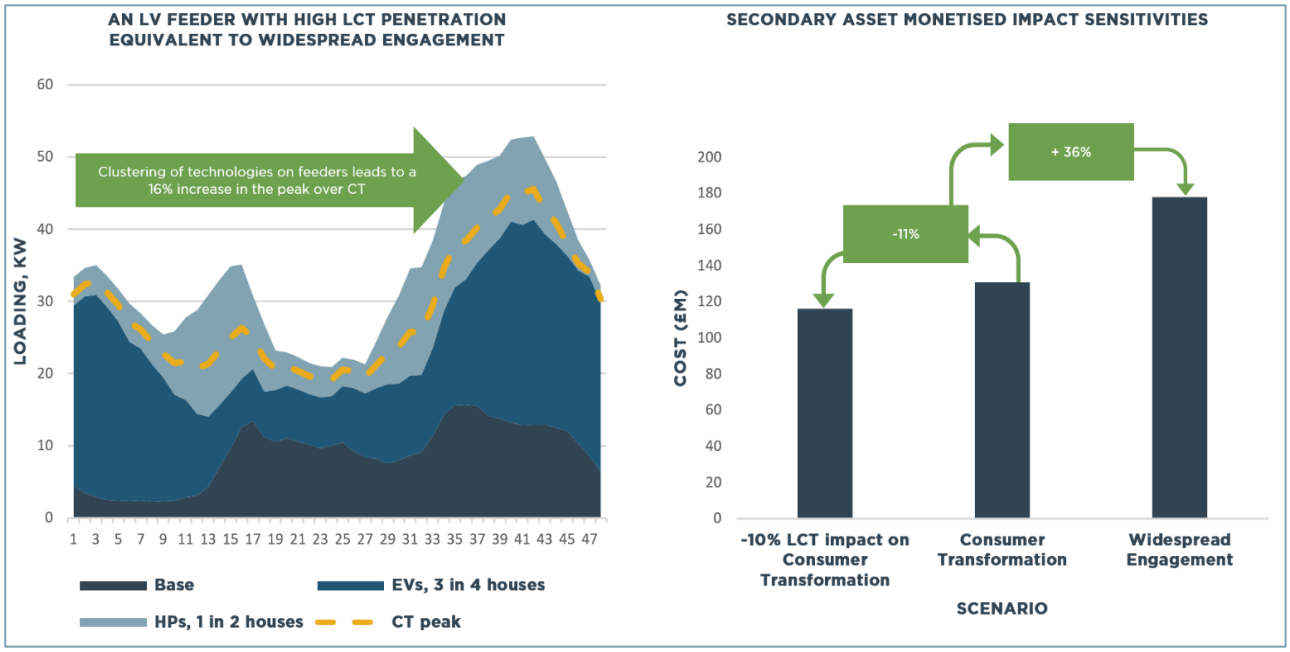


Figure 26- key results from varying LCT impact

## Sensitivity 2: Post 2030 constraints

We have analysed a range of scenarios in the post 2030-time frame and considered what this might mean for our ED2 Business Plan proposal. Figure 27 shows our forward view of combined 'network-wide' peak demand across SEPD (South) and SHEPD (North) for all four DFES scenarios in both 2020 and 2021, and also for the most relevant CCC scenario. It is important that our ED2 Business Plan takes account of, and is robust to, these alternative views of the future.

Figure 27 shows that the peak demand at the end of ED2 – even in the most aggressive scenario shown (CCC 'Widespread Engagement') – is realised by the most conservative scenario (DFES 2021 System Transformation) before the end of ED3. It is, therefore, more a case of *when* the demand will be met, rather than *if* it will be met.

The important conclusion from this analysis it that capacity interventions in the ED2 period are at a **very low risk of being stranded** for the foreseeable future, with LCT uptake under all credible scenarios expected to deliver the demand levels currently anticipated in the network planning time horizon.

Moreover, if we are to ensure that future pathways are not foreclosed and distribution network is a facilitator for, and not an obstacle to, the delivery of net zero – then it is both prudent and efficient for us to plan and invest now for this projected outcome.

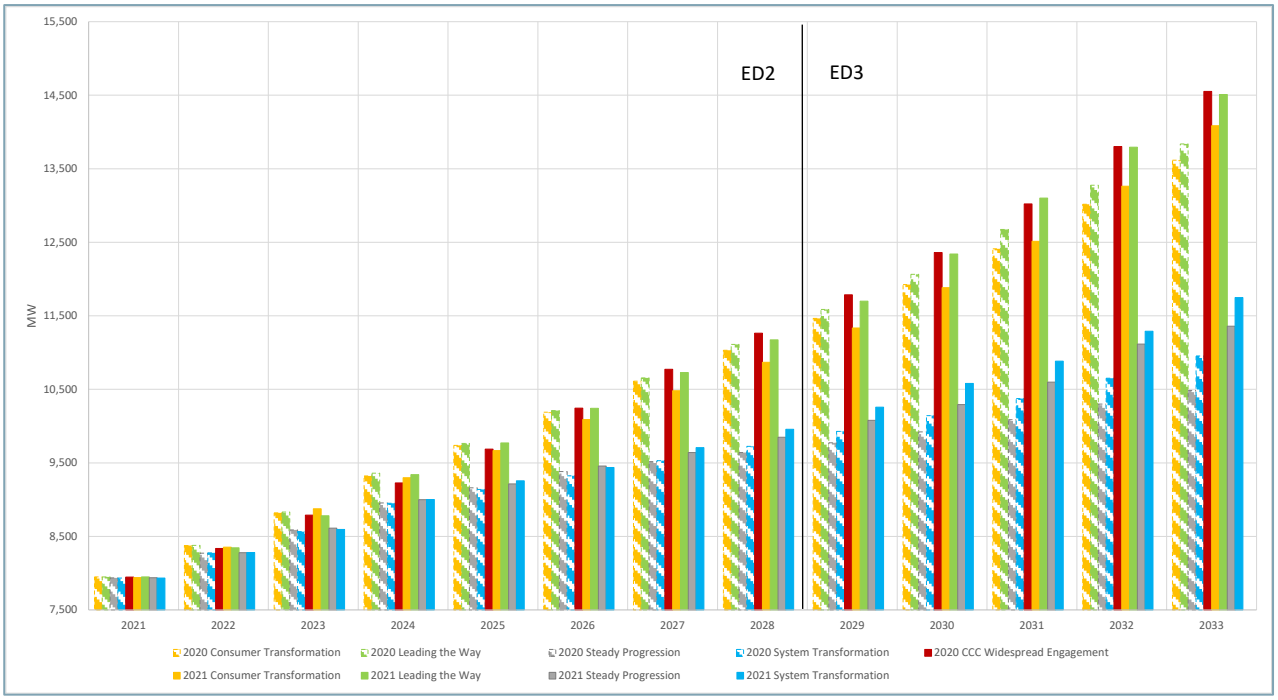


Figure 27 – forward view of network-wide peak demand

Network-wide peak demand is measured at the GSP level. And so, whilst this may provide *some* indication of overall demand at the highest levels in our network, it does not correlate strongly with the overall capacity needs and, therefore, the load-related expenditure requirement, of our network. This is particularly the case at the lower voltage levels (e.g. HV and LV) where we are anticipating significant increase in the number of LCT connections – both distributed generation and demand. This 'disconnect' between GSP maximum demand and capacity needs of the lower voltage networks, will continue to diverge as we move towards DSO, more distributed generation (e.g. PV) and local balancing of generation and demand. EVs and heat pumps are a major contributor to the increase in demand seen in all credible scenarios – DFES and CCC – shown in Figure 27[52].

## Sensitivity 3: Percentage of our load plan which could be regarded as anticipatory

A key principle of load-related investment is making timely interventions in anticipation of future growth in supply and demand connected to our network. Being based on a forecast set of assumptions our investments are not only designed to meet current network constraints but are also designed to be futureproofed to later year growth. This principle is important so that we minimize the disruption to customers wanting to connect and to society at large. As far as possible we aim to adopt a 'touch the network efficiently' principle (as detailed in our Deliverability Strategy Annex, 16.1) in developing the network to deliver net zero. In delivering anticipatory investment however we need to be cognizant of the potential for asset stranding and ensure that we minimise this risk. Our use of flexibility is a key tool which gives us some option value before committing to costly and irreversible constructed network interventions.

As part of our decision-making, we have sought to understand how much of our load-related plan could be regarded as anticipatory in nature and how this might change with changing demand.

A measure of network utilisation through the load-index on Primary network and utilisation banding on the Secondary network can provide some insight into this; but is limited in that no consideration is given of the extent to which proposed investment is directly linked to growth in peak demand in ED2, or to increases in peak demand in future years.

We have sought to go beyond this measure of utilisation in order to test the sensitivity of our overall load-related investment plan to changes in peak demand. To do this we have devised an equation for 'percentage anticipatory' which aims to provide an indication of the amount of the proposed investment which could be classified as anticipatory (i.e. not directly linked to the growth in peak demand in ED2). Importantly it allows testing of how changes in peak demand could impact the percentage of investments classed as anticipatory in the ex-ante baseline – all else being equal.

$$\%\text{Anticipatory}_{\text{ED2}} = \frac{\sum_{\text{ED2}} \text{CapEx (Load)} \times \left(1 - \frac{\text{Peak demand}_{2028} - \text{Peak demand}_{2023}}{\sum_{\text{ED2}} \text{Capacity released}}\right)}{\sum_{\text{ED2}} \text{CapEx (Load)}}$$

Applying the above equation to our ED2 ex-ante baseline plan and testing sensitivities of peak demand for our licence area we observe the results in Figure 28. This highlights that the percentage of investment which could be classed as anticipatory in ED2 is linked to the growth in peak demand with the period. The CT scenario, our ex-ante baseline scenario for the first two years of the period, has the highest growth in peak demand and so the lowest volume of investments which are not classed as anticipatory. The Steady Progression scenario whilst having the highest absolute demand at the start of ED2 has a low growth rate in peak through the period, which means that should this scenario outturn then more of our investments could be classed as anticipatory in the ED2 period – relative to CT.

It is important to note however that these investments would not be stranded given the higher growth rates for the Steady Progression scenario post-ED2, as shown in the right-hand plot in Figure 28. This is equally true for the System Transformation Scenario. Leading the Way has a lower percentage anticipatory compared to System Transformation and Steady Progression owing to a slightly steeper change in peak demand growth, though not as steep as the Consumer Transformation. We observe higher percentages of anticipatory investment in the South versus North on account of the higher absolute spend in the denominator of the above equation relative to a lower difference in the peak delta over capacity release between North and South.

It should also be noted that the approach to assessing anticipatory investment, as described in this section, only accounts for additional capacity installed where a *known* network capacity *need* has been identified. It does not provide any indication of the capacity that might be provided where the *need* is less certain, but where the consequence cost of failing to meet a future demand need – albeit an uncertain need – is high. This can also be considered 'anticipatory' investment and is likely to become increasingly important as a means of managing uncertainty and maximising long-term value for customers.

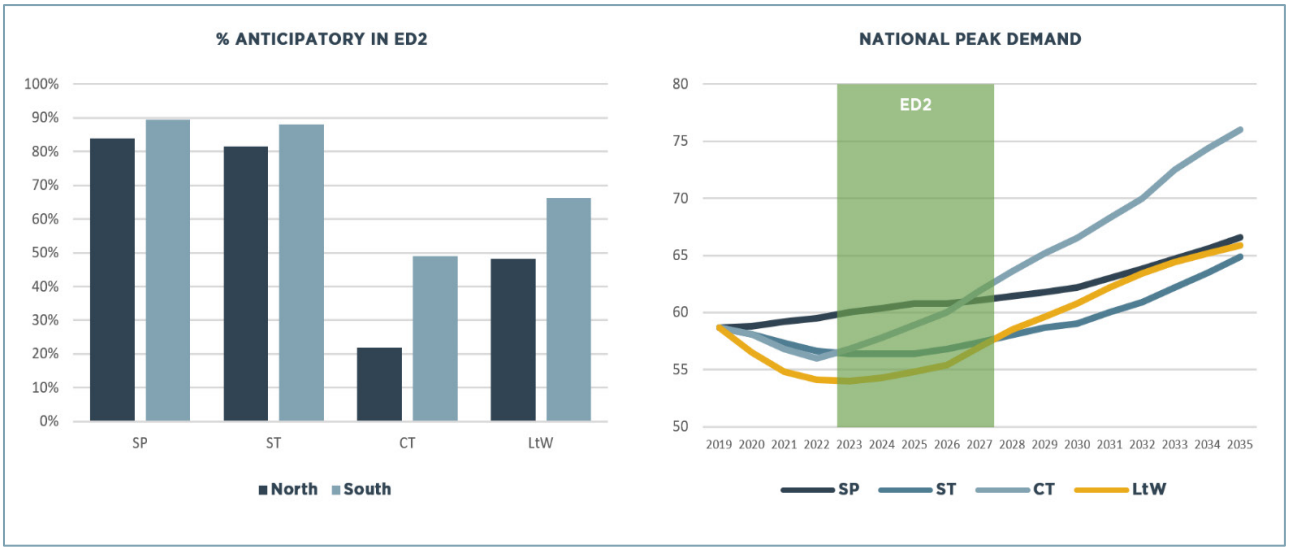


Figure 28: Percentage anticipatory investment sensitivity analysis

## Sensitivity 4: Flexibility cost

The widespread usage of flexibility during ED2 is a core priority in our plan, and section 4 of the main report articulates our overall strategy, plans and benefit appraisal for DSO and flexibility as a whole. Within our load related EHV investment, we have identified many schemes where there is a clear economic case for deferral through flexibility, at our central price assumptions of £150/MWh for availability and utilisation.

We have replicated our assessment process with two further price assumptions, halving and doubling the price to create a credible range. The results, shown in Table 26, show that decreasing the price can increase usage of flexibility by 15% in MVA terms. Doubling of the price equally results in a 15% reduction in deployment (in MVA terms). This demonstrates that the case for flexibility is extremely robust for 62 MVA of projects and could be made for up to 71 MVA at ambitious but credible flexibility prices. More details on potential price sensitivities for LV and HV flexibility can be found in ***Appendix F, Delivering Value Through Flexibility*** in our ***DSO Strategy (Annex 11.1)***[53].

Table 26- Flexibility Price sensitivities at EHV

| | £75 flex price | £150 flex price | £300 flex price |
|---|---|---|---|
| CAPEX Deferred to ED3 | £15.6m | £11.8m | £8.0m |
| CAPEX Savings in ED2 | £3.6m | £3.4m | £2.5m |
| Flex Costs | £1.3m | £1.1m | £0.5m |
| Flex Capacity considered MVA | | 497MVA | |
| Flex Capacity used MVA | 71 MVA | 62 MVA | 54 MVA |

[53] Appendix F, Delivering Value Through Flexibility, DSO Strategy (Annex 11.1).

## 6.5 EFFICIENTLY FUNDING THE PLAN

In this section we provide a synthesis of our ex-ante baseline plan and potential expenditure subject to uncertainty mechanism. This is mapped to regulatory requirements and outputs; including expectations set out by Ofgem on spend categorization. In Section 8 we provide more detail on how we propose dealing with future uncertainty.

Through our engagement with Ofgem it has been set out as a requirement that DNOs should articulate proposed expenditure in three categories to aid with understanding the nature of the anticipated expenditure and the proposal for efficient funding. These three categories are as follows.

1. Business-as-usual (Category 1)
2. Future proofing to ensure no future pathway is foreclosed (Category 2); and
3. Required only if underlying assumptions materialise (Category 3)

Category 1 provides for 'business-as-usual' – where we have high certainty of need and there is little sensitivity to the range of forecast assumptions. Category 2 represents the additional baseline expenditure required to ensure that future pathways are not foreclosed – 'futureproofing' to ensure that the foundations are in place to enable demand increase which occurs post-ED2 to be met efficiently. And Category 3 is the expenditure which likely to be needed, but only if specific forecast assumptions materialise, noting that the emergence of different assumptions may change the total level of spend in this category.

In the ED2 period we expect to spend £349.9m. In total however our expenditure requirements could reach £538m in the ED2 period. This excludes connection-related reinforcement.

### Category 1: Business-as-usual (BAU) load-related expenditure

Our approach to determining the 'business-as-usual' category of load-related expenditure is to base our proposed expenditure on the project and schemes which appear in all three of the net zero (DFES) future pathways. This is our test for high certainty of need. All of our proposed investments which appear in the System Transformation (ST) scenario, also appear in Consumer Transformation (CT) scenario and also in Leading the Way (LW). Our BAU expenditure is therefore based on DFES ST scenario. This represents £326.9m which is approximately 93% of our £349.9m[54] total BAU funding in ED2.

For the purposes of funding, we have divided this category of expenditure into two sub-sections: ex-ante baseline funded (Category 1a) and uncertainty mechanism funded (Category 1b).

#### *Category 1a: BAU – ex-ante baseline funded*

Our ex-ante baseline BAU funding includes **EHV** schemes where these are required by all net zero scenarios (in effect, DFES ST). For **HV and LV**, we only include schemes required by all net zero scenarios for the first two years in the RIIO-ED2 period in our ex-ante funding proposal. This accounts for £274.9m.

[54] This excludes connections-related reinforcement; only includes CV1-CV4.

*Category 1b: BAU – uncertainty mechanism funded*

To protect our customers against costs from forecast uncertainties, we have taken the decision that our ex-ante BAU funding only includes the HV and LV load related investment required in the first two years in the RIIO-ED2 period, and only if required by all net zero scenarios (DFES CT). Further explanation of the basis for this funding proposal can be found in Section 4 of this Annex. This accounts for £52.0m.

### Category 2: Futureproofing to build foundations and keep open future credible pathways

The second category of expenditure is that which we believe is needed to ensure that future options remain open – that is, the additional expenditure needed to ensure that we have the essential foundations in place to meet the potential demands of the future in a way that avoids inefficiency, duplication and unnecessary cost and inconvenience to customers and communities. Our proposal for this is that in years 1 and 2 of the ED2 period we commit the expenditure based on our view of CT – the scenario we have selected as the 'baseline' future pathway for ED2.

This additional expenditure – over and above ST – associated with delivering our investment in accordance with CT in this first two years of the period is £23m and will ensure the early and timely establishment of the capacity (supply chain, people and network) and ability required to deliver to CT throughout ED2 – should our anticipated baseline scenario come to pass. Failure to provide this level of capacity preparedness will mean higher costs and inefficiencies for customers in the longer term as the investment required to support net zero moves from being anticipatory and strategic in nature, to reactive and short-term focused.

Our total ex-ante baseline funding proposal is Category 1a (£274.9m) plus Category 2 (£23m), totalling £297.9m.

### Category 3: Required only if underlying assumptions materialise; uncertain expenditure

The third category of expenditure is that associated with CT beyond the second year of ED2. Whilst we believe that this represents a credible forward baseline scenario to the end of ED2 and beyond, we accept that this relies on specific assumptions materialising and therefore presents an intrinsic level of uncertainty. For this reason, we propose that this expenditure category is funded through uncertainty mechanisms whose triggers are clearly defined. Work continues by DNOs and Ofgem to define these. This category of expenditure is estimated to be £188.3m.

Figure 29 shows disaggregation of the load-related reinforcement into the three categories which Ofgem has asked network companies to consider.

*Why are we only requesting two years of ex-ante baseline funding for Consumer Transformation?*

The ability and confidence to being able to deliver the investment plan is critically important. We will enhance our capacity to execute and mobilise (people, workforce, systems and supply chain) in the first two years of ED2. Our ability to ramp-up our load-related delivery capability in the first two years of ED2 will act as a measure of our commitment and endeavour to ensure that future (prudent and efficient) pathways to net zero remain intact.

Two years is the typical lead time required to plan, design, construct and commission our larger substation and circuit investments. We need to remove uncertainty and make decisions in the remainder of ED1 if we are to mobilise and execute network investment plans. Also, major customer connections application enquiries are often 'live' up to 2 years ahead of need. A time period less than 2 years is likely to be insufficient to plan and prepare for efficient and timely delivery of the required capacity.

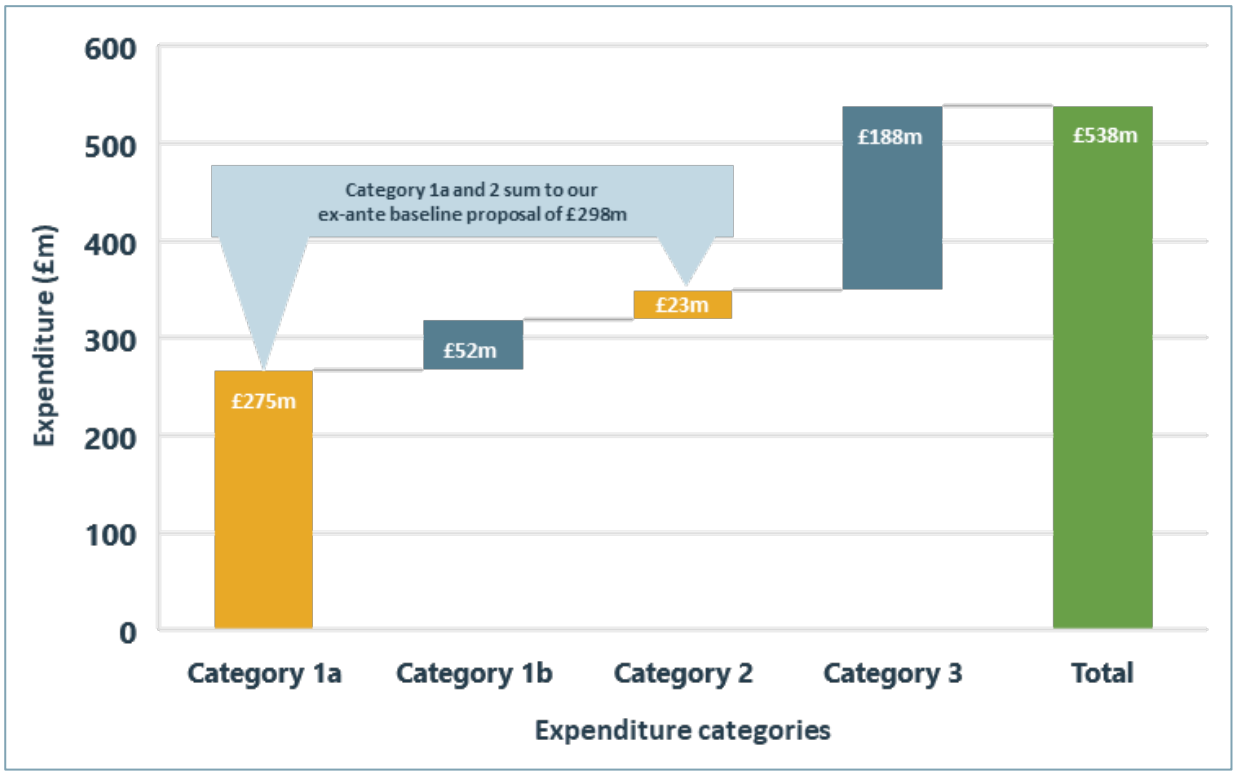


Figure 29: Total ED2 load related expenditure distributed by category (excludes connections-related reinforcement)

In the best case, a short-term, reactive approach to development of the network will burden customers with unnecessary costs and inefficiencies. In the worst case, failing to prepare whilst waiting for a high degree of certainty of the investment 'need' risks failure to provide sufficient capacity at the right place, and at the right time. This would lead directly to customer and societal costs (e.g. customers have to wait for the local infrastructure before they can buy an EV) and the associated risk of failure to meet Government's net zero targets.

Conversely, we believe that committing to expenditure now for potential capacity needs beyond the first two years of ED2 is unnecessary and runs a higher risk of our customers having to pay higher costs than needed. We will maintain the 2-years planning time window as we move forward – drawing on uncertainty mechanisms to fund prudent and efficient load-related expenditure as we move through the ED2 period and beyond.

This is a key part of our strategy to ensure that no future pathway is foreclosed. Keeping open options for customers and being ready to mobilise and deliver according to the alternative scenarios should the assumption materialise.

Some of our expenditure in ED2 is uncertain and will depend upon specific assumptions materialising

Finally, the third category of expenditure is that associated with CT beyond the second year of ED2. Whilst we believe that this represents a credible forward baseline scenario to the end of ED2 and beyond, we accept that this relies on specific assumptions materialising and therefore presents an intrinsic level of uncertainty. For this reason, we propose that this expenditure category is funded through uncertainty mechanisms whose triggers are clearly defined. Work continues by DNOs and Ofgem to define these. This category of expenditure is estimated to be £188.3m. Figure 29 shows disaggregation of the load-related reinforcement into the three categories which Ofgem has asked network companies to consider.

In summary we be believe the CT scenario provides a credible forward projection for ED2, particularly given the strong evidence of support from our stakeholders. However, we feel that in terms of efficient funding, our ex-ante baseline allowance should provide for the minimum required investment required under all scenarios – as determined by the ST scenario (Category 1), plus the amount required to ensure that no future pathway is foreclosed. We have achieved this by including in the ex-ante funding proposal the additional efficient expenditure required for CT scenario in the first two years of the ED2 period (Category 2). Adjustment to the baseline funding – including any additional funding required over-and-above that for ST in years 3 to 5 of the period, will be provided via the uncertainty mechanism. We would still anticipate an appropriate uncertainty mechanism operating for the full 5-year period.

Our ex-ante baseline allowance proposal is therefore approximately 55% of our total expenditure which we anticipate requiring in ED2 under Consumer Transformation.

# 7 A CREDIBLE TRANSITION FROM ED1 TO ED2

Since the start of RIIO-ED1, we have released over 650 MVA of capacity on our network (primary reinforcement) and connected over 2,750 MW of low carbon technologies to our network. Through the introduction of innovative solutions such as flexibility and Active Network Management (ANM) we have connected customers to our network more efficiently, delivering significant savings, and paving the way for the roll-out of innovation into business as usual in ED2.

Overall, in both licence areas, network demand did not increase as anticipated at the start of RIIO-ED1. This was primarily the result of slower recovery from economic downturn. A number of customer-driven schemes were also cancelled, and several large connections e.g. data centres in the SEPD network area have had a particular impact. However, targeted reinforcement has still been required at the local level to deal with constraints and to provide firm capacity. We have also experienced pockets of rising demand across both licence areas. Overall, downward pressures have been slightly offset by the level of distributed generator connections in SEPD and SHEPD, driving an increase in the associated apportionment reinforcement works.

Our ED1 forecast was based on an assessment of likely economic uptake and assumption that tariffs to incentivise uptake would continue to encourage significant uptake of LCT. There will have been delays in uptake compared to RIIO-ED1 expectations resulting from a combination of factors such as economic growth and technology availability, and the wider context has changed significantly since our ED1 forecasts were produced.

We are now seeing increases in customers seeking to connect to our network in the latter years of ED1, with the trend expected to continue into ED2, in particular as a result of the expected increases in EVs and heat pumps. We also anticipate that the number of embedded renewables will progressively increase in the latter years of ED1 and into the ED2 period. Enabling the connection of increased levels of generation, in particular in the North, will help create a solid foundation to support governments' net zero ambitions.

### EV chargers

There are over 40,000 EV chargers in total installed in our licence areas. This compares to a forecast of 42,600 EV chargers (28,000 fast chargers) by 2019/20 in our RIIO-ED1 Business Plan. We have seen a 65% increase in EV connection notifications/applications across SSEN from 2019/20 to 2020/21 (62% increase in SEPD, 59% increase in SHEPD).

We do not have visibility of all EV chargers connecting to our network, as we are not always notified by installers. Since the start of ED1, we have had formal notifications for over 7,000 EV fast chargers (170MW). We are seeing a steep increase in the number of installation notifications across both our licence areas, with a 40% increase in our SHEPD network and 151% increase in our SSES network in 2019/2020 comparison to 2018/19.

We expect to see this trend continue for the remainder of ED1 and into ED2. Based on our current DFES projections[55], and using Consumer Transformation, we expect to see around 1,660MW of EV chargers connect to our network by the end of RIIO-ED1, rising to around 6,000MW by the end of ED2.

### EVs

We did not provide a specific forecast for EVs in our ED1 Business Plan. According to Government data, at the end of 2020 there were over 120,000 plug-in hybrid and fully electric vehicles registered in our licence areas[56]. This includes cars, buses and coaches, LGVs, and HGVs.

We expect to see significant increases in EVs over the remainder of ED1 and into ED2. Based on our current DFES projections and using Consumer Transformation, we expect to see over 245,000 EVs in our network areas by the start of RIIO-ED2, rising to 1.3m by the end of the period.

### Heat pumps

According to government data there are over 20,000 heat pumps in total installed in our licence areas[57]. We do not have full visibility of all heat pumps connecting to our network, as some are 'behind the meter' and we are not always notified of their installation. In 2019/20, we received formal notification for over 1,461 domestic heat pumps on our network. This compares to a ED1 forecast of just over 92,000 by 2019/20. However, as with EV chargers and EV number, we expect to see a significant increase over the remainder of ED1 and into ED2. Based on our current DFES projections and using Consumer Transformation, we expect to see over 208,000 heat pumps in our network areas by the start of ED2, rising to over 800,000 by the end of the period.

### Efficiencies and innovation benefits

We recognise the benefits that can be delivered by embracing flexible solutions ahead of reinforcement, where appropriate. We have achieved savings of just over £60m for customers across both our networks in ED1 through flexible solutions. We have introduced flexible connection solutions and Active Network Management (ANM) type innovations which help avoid investment and allow customers to connect quicker and at lower cost. This includes schemes on the Isle of Wight in SEPD and on the Western Isles in SHEPD, where we have deferred load expenditure through to the use of ANM schemes.

We provide a detailed overview of our approach to Flexibility and Whole Systems in ***DSO (Chapter 11)*** and ***Whole Systems (Chapter 12)*** of this Business Plan respectively.

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55 Source: https://www.ssen.co.uk/SmarterElectricity/

56 Source: DVLA/Department for Transport Vehicle Licensing Statistics.

57 Source: Renewable Heat Incentive (RHI) data.

# 8 WHAT IF THE FUTURE IS NOT AS PREDICTED?

Our business plan submission is ex-ante based, and we have used the DFES scenarios to inform our baseline allowance proposal. In Section 6.5 we outline our strategy to efficiently fund our plan which is to request only the first two years of funding to deliver Consumer Transformation as the baseline scenario. We have also identified that there may be up to £240m[58] of additional allowance needed if underlying assumptions in the DFES materialise; with this allowance funded through an uncertainty mechanism.

The assumptions underpinning the load-related baseline plan and the associated load-related expenditure are likely to change. The trajectory for net zero, and the trajectory of the local authorities in our licence area may alter significantly during ED2. Changes in public policy of democratically elected bodies may occur; therefore, might changes in customer and stakeholder requirements; or in technology evolution; and changes in energy market development can have a significant bearing.

The four DFES 2020 scenarios attempt to capture the uncertainty faced to a reasonable extent, but they are not exhaustive. For example, the key differentiators between our baseline view and ST scenario, are that ST has:

- Substantially lower uptake of battery EVs (especially for the North licence area)
- Lower penetration of domestic and non-domestic EV chargers
- Substantially lower uptake of domestic and non-domestic heat pumps (especially relative to the Consumer Transformation trajectory used for 2023-2025)
- Substantially lower uptake of small-scale solar PV, especially at the domestic (<10kW) level

The key differentiators of Leading the Way (as compared to the baseline plan) include:

- Substantially higher uptake of battery EVs (especially for the North licence area)
- Substantially higher penetration of domestic and non-domestic EV chargers
- Substantially higher uptake of domestic and non-domestic heat pumps (especially non-hybrid heat pumps)

[58] This includes £52m of Cat 1b (BAU) expenditure – funded through UM. See Section 6.5.

### Net zero Islands Study

Our ED2 baseline plan has been constructed from scenarios developed in 2020. We know that these can evolve over time and the ED2 regulatory framework provides for this through use of uncertainty mechanisms. An example of how uncertainty mechanisms might be used in the ED2 period is on the Isle of Wight, where we have proposed a distinct net zero Islands study in early 2022 to gain a more detailed understanding of potential generation in the area.

We will work with the Isle of Wight council, the developer community and local stakeholders – ahead of the start of the ED2 period – to consider how best to use uncertainty mechanisms to support the delivery of net zero. For example, should growth in demand or generation exceed our forecast, and to ensure that network constraints do not restrict local aspiration in achieving net zero, the uncertainty mechanism will enable us to invest in network upgrades in addition to those detailed within our ex-ante baseline plan.

It is possible that our upper end of additional spending required could be exceeded by more ambitious Government policy or faster changes in the market outside of the DFES scenario envelope. Equally the pace of achieving net zero may be slowed by a variety of factors in the ED2 period and so it may become necessary to delay parts of our baseline plan until ED3 when clarity emerges.

Having an agile and adaptive regulatory framework which can adjust the level of total expenditure in ED2 to accommodate changes in external influencing factors, is vital.

In ***Uncertainty Mechanisms (Chapter 17)***, ***Uncertainty Mechanisms (Annex 17.1)***, and particularly the Appendix to ***Annex 17.1*** regarding Strategic Investment, we set out our proposals for managing externally driven uncertainty in the ED2 period. This includes proposals on a range of uncertainty mechanisms which can allow allowances to adjust for specific events. Ofgem has also set out, through its Sector Specific Methodology Decision (SSMD)[59], uncertainty mechanisms applicable to the whole distribution sector and some applicable to all RIIO-2 companies.

We have been working directly with Ofgem and other stakeholders over the course of the last 18 months to consider the need case and principles of operation for new forms of uncertainty mechanism, applicable to all DNOs. We propose that Ofgem pursues an automatic (volume driver) uncertainty mechanism for load related expenditure. We believe that an automatic mechanism is necessary so DNOs can respond quickly to the changes likely in the ED2 period, which the existing load related re-opener mechanism does not currently allow for. We believe that the uncertainty we face in ED2 is continuous in nature. We believe that the uncertainty is likely to be characterised by continuous distributions with a very large set of possible outcomes and cost impacts (for example, uncertainty over the number of electric vehicles purchased by consumers over ED2).

Based on our DFES scenario analysis we believe this uncertainty could range from:

- South: £206m to £409m, relative to a baseline of £227m (-£21m to +£182m)
- North: £62m to £129m, relative to a baseline of £71m (-£9m to +£58m)

59 https://www.ofgem.gov.uk/system/files/docs/2020/12/ed2_ssmd_overview.pdf

We have discussed at length with industry stakeholders the key considerations and principles of operation for a UM in this area. Through our working group involvement over the last 18 months we have heard in detail the views of a range of stakeholders, including consumer advocate groups and academia. Furthermore, we have spoken directly to stakeholders relevant to our licence areas on the need case for a UM.

Our Stakeholder Advisory Panel, for example, has recognised the need for this UM across the sector, noting that the degree of use will vary across DNOs due to regional variations in LCT uptake and broader net zero transition.

Additionally, our broader stakeholder community has told us that they support the mechanism, and additionally the need for significant anticipatory investment, but expressed concern that a capacity-based volume driver could lead to excess customer bill volatility if not designed carefully, given the significant investment required. We have taken this into account while continuing the iterative design process with Ofgem in the working group. As the working group will continue to develop the mechanism through the determination phases of the regulatory process, we set out our current view of the optimal design of the mechanism in the ***Annex 17.1*** appendix. The call-out box summarises the key features of the optimal design.

### Strategic Investment UM – Key Features

- Expenditure is triggered by our annual planning cycle which is transparent, and stakeholder led; each year of ED2 we will update our plan for the following years where we are triggering certain works (including flexible solutions)
- The planning cycle includes: (1) the stakeholder led DFES, (2) technical network assessments, and (3) economic network assessments. Each step has an associated transparent, published methodology
- Expenditure is based on where this cycle identifies requirements for intervention within a short time horizon, or where anticipatory investment is needed due to the deliverability of longer-term requirements, or where more efficient work packages can be created through advancing interventions for some requirements
- These efficient work packages can be driven by a range of potential synergies: Whole Systems options, network access being facilitated by another driver, or multiple requirements at the same site, for example
- We will generate standardized evidence on our interventions to demonstrate that we have considered the right range of options, at the right time, based on the best forecasts, and selected the options that maximise consumer value
- We will maximise consumer value by stating – ahead of delivery for non-baseline interventions – how we will balance the risk of anticipatory investment against the need to keep pace with LCT uptake
- Where DNOs do not follow the methodologies they set out, Ofgem can leverage existing regulatory tools to disqualify relevant allowances
- Ofgem's role can be minimal, but with the ability to intervene each year following reporting of volumes
- We present our best view of unit cost allowances (UCA)

# Appendix A MINIMUM REQUIREMENTS

Table 27 provides details of the relevant minimum requirements and where we have described how we address these within this document.

Table 27 – Mapping of Ofgem Minimum Requirements

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| **5.1** | Network operators will need to play a proactive role in ensuring the local grids are ready for the Net Zero transition. They will need to plan to accommodate increasing demand that will come from the electrification of heating and transport, while accounting for and maximising the potential of these and other new technologies to provide system flexibility and limit the need for network upgrades. We also expect them to identify and take steps to minimise the impact that uncertainty might have on consumers. | See **section 4** for the steps we take to minimise the impact of uncertainty on consumers. |
| **5.2** | DNO investment plans should therefore be based, as far as is practicable, on well informed and justified forecasts of demand and generation growth, which will allow Ofgem to be able to undertake comparative analysis of forecast expenditure between DNOs. | **Section 6.2** and **Appendix E** address how we have developed our forecasts. |
| **5.3** | In Chapter 4 of our RIIO-ED2 Methodology Decision, we said that there are significant benefits to DNOs applying common sets of forecast assumptions for the purposes of investment planning. We are using this Business Plan Guidance to provide these sets of forecast assumptions. | N/A - Guidance Only. |
| **5.4** | DNOs must demonstrate that their forecasts have been informed by the range of assumptions found in the Net Zero compliant energy pathways in the Electricity System Operator's 2020 FES, and the Climate Change Committee's 6th Carbon Budget. This range of pathways is consistent with the Government's announcement to end sales of new combustion engine vehicles by 2030 and for all new cars and vans to be fully zero emission at the tailpipe from 2035. The assumptions are also consistent with the recently announced Government target to rollout 600,000 heat pumps a year by 2028. | **Section 6.2** addresses how we develop our forecasts, and our sensitivities and **section 6.4** discusses variation of some of these assumptions. |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| **5.5** | From the Electricity System Operator's 2020 FES, and the Climate Change Committee's 6th Carbon Budget, we have extracted key assumptions set out in the table below that we consider are relevant for investment planning. These show the projected forecasts for total demand, heat pump demand and penetration, and EV demand and penetration for 2030. DNOs must use these key assumptions as part of determining the range of demand for their network. The full set of assumptions is available at the Electricity System Operator's and the Climate Change Committee's websites. Between now and 2030, there is a reasonable degree of consistency between different forecast pathways and we believe this will enable DNOs to have a higher level of certainty on the need for investment than would otherwise be the case. | **Section 6.2** describes how the scenarios we have used, and the key assumptions underpinning them, inform our forward projection of peak demand. In **Section 6.4** we also show how our view of demand scenarios post-2030 supports the investment decsions in ED2. |
| **5.6** | We also expect DNOs to assess the need for investment beyond 2030 that may be required in order to deliver against Net Zero targets. The pathways identified above may provide a useful basis for predicting longer-term levels of demand, although we note that in the period beyond 2030, there is increasing divergence between the demand indicated by different pathways. We expect DNOs to take into account the degree of divergence between pathways when identifying both the potential need for investment and the certainty they have on the investment being required under a range of future scenarios. | **Section 6.3** discusses how we assessed network requirements across all DFES, and our thinking for how this divergence can be accounted for through plan funding is outlined in **Section 6.5**.<br><br>Our Strategic Vision for meeting net zero ensures that we can meet network requirements post-2030 whilst protecting consumers against inefficient expenditure and is set out in **Section 4.1.** |
| **5.7** | Each DNO will have to translate these national pathways into scenarios that are applicable for its licence area. In establishing these scenarios, DNOs should engage with local stakeholders to understand what trajectory for decarbonisation is likely to be followed in that licence area. As a minimum requirement under Stage 1 of the BPI, DNO Business Plans must set out a detailed description of the process through which this engagement has been conducted. This must include evidence of structured and effective consultation with stakeholders and a demonstration of how this was supported with input from democratically accountable bodies. | **Section 6.2** outlines how we co-created the scenarios with local stakeholders. |
| **5.8** | Once the scenarios are developed, the licensees must include evidence of:<br>• relevant network planning data being made available to external stakeholders in a digitised and open form. This should include the provision of heat maps, where relevant. | **Section 6.3** covers how we reach out to stakeholders to share information on where we require flexibility services. Details of our planning scenarios are also made available in **Section 6.2**. |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| | • the manner in which the data from this modelling was made available to other stakeholders, in line with Data Best Practice guidance. | |
| **5.9** | DNOs will need to transparently set out how they have translated forecasts on overall demand into an increase in demand at peak times. This will involve DNOs explaining clearly their assumptions on peak demand from heating that best identifies the projected uptake (in millions) of heat pumps for the period of RIIO-ED2. DNOs must also describe the anticipated EV uptake rates for this period in their licence area and the impact these will have on the modelled peak demand for electricity, as part of their peak demand estimations. | This is explained in detail in **Section 6.2.** |
| **5.10** | A DNO's peak demand estimation must include the assumptions they have made on how the emergence of flexibility markets, the development of smart technologies and changes in consumer behaviour could impact on peak demand growth. We also expect DNOs to undertake a sensitivity analysis around this to demonstrate how changes in these assumptions could impact on the level of peak demand, and any associated investment requirements. | This and other sensitivity types are discussed in **Section 6.4.** |
| **5.11** | In developing the scenarios, the licensees must include evidence of how this process took account of the alignment between regional and national targets and the reasons for any differences. | This is discussed in **Section 6.2** in the sub-section entitled ***'Reconciliation of DFES and FES'*** (page 48). |
| **5.12** | There are several methods that a DNO could use to establish a forecast of demand expected for its areas, and we are not prescribing which a DNO should use or the evidence they should provide in accordance with paragraph 5.7. While we are not mandating a requirement to apply for example: the guidance on best practice for developing Local Area Energy Plans, the draft framework for devolved, regional and local energy planning provided by Scottish Government, or the Energy Networks Association's (ENA) Open Networks Project's work on Distribution Future Energy Scenarios (DFES) and development of a 'best view' network forecast, we do consider that these are helpful to illustrate the type of information and evidence that could support investment proposals to meet localised forecasts of demand. | Our method described in **Section 6.2.** |
| **5.13** | In any case, the DNOs must detail the nature of the modelling that was conducted to establish a regional forecast to Net Zero in their Business Plan. | Detailed in **Section 6.2.** |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| **5.14** | We anticipate that a DNO's forecast that is generated through the above process is likely to inform their investment proposals. For their business plan however, we require more than an investment plan based around single set of assumptions that a DNO views as most likely to arise. | How we make our decisions, and how our investment may vary based on more than one view, is outlined across **Sections 6.3, 6.4 & 6.5.** |
| **5.15** | DNOs must use this analysis to distinguish between investment that is reasonably certain to be required across different pathways, from that which may only be required under a specific set of circumstances, even if these represent a DNO's most likely view of future demand. | Variation in investments required across different scenarios are discussed in **Section 6.3.** |
| **5.16** | They must seek to identify an investment strategy that is robust across pathways/scenarios, i.e. which performs well (is close to optimal) no matter which pathway/scenario occurs. | The logic behind how our investments could vary, and therefore the split between uncertain and certain costs, is covered in **Section 6.5.** |
| **5.17** | They must seek to identify an investment strategy that is robust across pathways/scenarios, ie which performs well (is close to optimal) no matter which pathway/scenario occurs. It is possible that a DNO's investment strategy may not be quite optimal for any single possible scenario, in that making it suitably robust may involve a degree of proofing against whichever future scenario occurs. | Our approach to the timing of investments is explained in **Section 6.4** in the sub-section **6.4.5 '*How we applied flexibility and timing of interventions*'.** |
| **5.18** | We expect the use of flexibility to be fully considered by DNOs and clearly outlined as part of the analysis presented in business plans and we anticipate it will form a key part of expenditure funded through baseline allowances. | Our consideration of flexibility is explained in **section 6.4.** |
| **5.19** | Where a DNO brings forward investment proposals for which it is seeking baseline funding, we will expect them to set out what projects and/or volume of additional capacity it is intending to deliver through these allowances. We expect DNOs to consider the application of PCDs to this expenditure in circumstances where there would be no impact on performance against other RIIO-ED2 outputs if the allowance provided was not subsequently used to deliver the project and/or volume of capacity intended. This may particularly be the case for any expenditure intended to provide additional capacity to demand projected to arise beyond 2028. | LRE's link to regulatory outputs is shown in **Table 1** and **Table 2** in **section 4.** |
| **5.20** | To support DNOs in presenting well-justified proposals, Appendix 7 provides more detailed guidance on the information we expect to be provided to demonstrate the end to end process it has undertaken to develop a robust investment plan. | See Cost Efficiency (**Annex 15.1**). |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| **5.21** | As a minimum requirement under Stage 1 of the BPI, DNOs must submit cost information as part of their Busines Plans, as set out in this section. | See below for specific references. |
| **5.22** | In proposing costs for operating and developing their networks, companies must explain their costs/workload forecasts, particularly where these diverge from historical trends. In particular, we expect companies to provide information in their Business Plans on:<br>• cost drivers.<br>• consideration of options.<br>• justification of costs, including the proposed profiling of costs.<br>• how efficiency and innovation will be used to reduce costs. | The main cost driver changes are discussed in **section 7**. Our consideration of options is discussed in **section 6.3.6.** Our deliverability challenge and how that impacts efficiency is discussed in **section 5.3**. Our overall costing is discussed in Cost Efficiency (**Annex 15.1**). |
| **5.23** | Companies must complete the Business Plan Data Templates (BPDTs) in accordance with the Ofgem BPDT guidance. | BPDTs have been completed in accordance with Ofgem's guidance. |
| **5.24** | Business Plans must clearly set out the key drivers of expenditure for the RIIOED2 period - for example, growth in demand, conditions of assets/utilisation, legislative requirements, and any other relevant drivers. | Our drivers for network requirements are set out in **Section 6.3** and discussed in general in the Executive Summary and Introduction. |
| **5.25** | Business Plans must clearly justify the need for new investment, including:<br>• information on current levels of network utilisation and changes to utilisation based on the different forecast growth pathways that we have identified above, including their "best view". We expect that information on current and forecast network capacity will be published in accordance with Data Best Practice. This must include its integration into the joint network mapping platform that the ENA's members have already been working on. This must be undertaken in a way that is consistent with Ofgem-led reforms to the LTDS which proposes enhancing data on headroom to the 11kV network, and the Network Development Plan, where readily accessible data on network headroom will form a central component.<br>• the different options considered for meeting future network requirements, including the cost of "doing nothing" and of "deferral" options and the associated cost benefit analysis (CBA). These options should include, where appropriate, the availability of potential market solutions to the system need, and whether any 'whole system' solutions are available. | How we populated options for assessment is described in **Section 6.3** and our network utilisation forecasts and how we used timing are shown in **Section 6.4.** |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| | • we expect DNOs to make the best use of existing network capacity first, by fully utilising flexibility technologies to manage changes in peak demand. A network capacity upgrade may be necessary where flexibility is likely to be insufficient by itself to meet anticipated growth in peak demand. Where this is the case, DNOs should show that they have considered the option value provided by flexibility in the timing of their upgrades to capacity. In doing so, they should account for the long-term prospects for demand across different future scenarios and size capacity upgrades so they minimise long-term costs for consumers.<br>• for options discounted by DNOs at this stage, full reasoning, detailing key assumptions and selection criteria given for exclusion.<br>• the reasons for the timing of investment under the different options considered, including expected outputs (eg the delivery of an increment in boundary capacity transfer, the delivery of an electricity link) related to the investment and year of delivery. | |
| **5.26** | In support of costs proposed, Business Plans must include:<br>• evidence of the efficiency of their costs, for example as compared to historical benchmarks and/or benchmarking with national and international comparators.<br>• details of assumptions and justification for projected changes in the efficient levels of unit costs over time (ie ongoing efficiencies) caused by improvements in project delivery, technological innovation, procurement efficiencies, etc.<br>• a clear rationale for any associated assumptions they consider we should use when assessing costs. For example, justification for the extent to which regional and company-specific factors determine material (higher and lower) cost variations.<br>• details of the activities and indicative costs that they propose are directly funded through totex allowances and that will be associated with achieving service levels.<br>• details of which categories of expenditure are more uncertain and more difficult to forecast using historical/independent benchmarks. This should include:<br>○ the risk of underutilisation/stranding that new/existing investments might face in the future under a range of plausible forecast scenarios.<br>○ the risk that an alternative solution may be the most efficient means of addressing the network requirement. | Our stranded asset analysis is in **Section 6.4.** |

| | Ofgem minimum requirement | Where and how this is addressed in narrative |
|---|---|---|
| | ○ the risk that the investment is premature.<br>• where this is the case, we expect companies' Business Plans to demonstrate consideration of mechanisms that mitigate risk associated with uncertainty, and/or other evidence to justify their submitted costs. | |
| **5.27** | For new or existing assets that face a risk of underutilisation, Business Plans should set out the monitoring and mitigation they will put in place to reduce this risk. For new assets (ie those assets that companies are planning to invest in and have included in Business Plans) that face a risk of underutilisation, network companies should ensure before undertaking the investment they have clear evidence of need, such evidence might include LAEPs. | Our stranded asset analysis is in **Section 6.4.** |
| **5.28** | Where a DNO considers an investment is certain under all scenarios, they will be expected to provide justification for this view. | This is covered by our constraint analysis in **Section 6.3** and by our funding proposal in **Section 6.5.** |
| **5.29** | Business Plans should demonstrate how their expenditure forecasts map onto relevant ODIs and PCDs. | There are no linked ODIs or PCDs for Load. Table 1 shows how Load drives our overall plan goals. |

# Appendix B ENHANCED ENGAGEMENT

## *Local Network Plans*

- Overview: **We plan to meet increased demand on our network from low-carbon technologies**
- Total cost: **£510.2m** (Baseline load and connections-driven reinforcements with additional uncertainty mechanism funding in period)
- Contribution to annual customer bills: **£13.90 (South), £12.78 (North)**
- Consumer benefit: **£110m carbon benefits and £120m financial benefits over one year, enabled by ensuring LCT customers are able to connect on time. We expect these benefits to recur over each year of the ED2 period and beyond.**

### RIIO-1 context

In 2019/20 we served 782,536 customers across our North of Scotland region (up 4,232 from the previous year), and 3,092,275 customers in our central Southern England region (up 24,287 on the previous year).

Our challenge for ED2 is to be proactive about readying local networks to accommodate increasing demand that will come from the electrification of heating and transport required to achieve the net zero transition, while optimising reinforcement. Failure to provide sufficient capacity at the right place, and at the right time, is likely to lead to inability to meet net zero demand requirements. Investment must be timed so as to deliver long-term value to customers whilst being mindful of bill impacts – especially for those in vulnerable situations who must not be left behind in the push for net zero.

## *Engagement synthesis*

| Stakeholder engagement | |
|---|---|
| **Engagement details** | **Insights derived** |
| **Fuel Poor, Future Customers and Customers in vulnerable situations and medium business customers**<br><br>We tested our **Load investment strategy, outputs and costs** through qualitative focus groups to get insights into the **acceptability and affordability** of our Draft Business Plan | • These ***customer segments*** felt the net zero outputs were important and should be a priority. The costs were broadly supported athough fuel poor customers were concerned about bill impacts. Customers in vulnerable situations urged specific action to support these customers and urged SSEN to continue to engage and educate customers on net zero investment plans. [E156] |

| | |
|---|---|
| **National Government**<br><br>We engaged MPs and MSPs about our Draft Business Plan via bilaterals | **Northern Scotland**<br>• A range of MSPs were engaged on the net zero proposals representing: Argyll and Bute; Angus; West Aberdeenshire and Kincardine; North East Scotland; Dundee City West; Western Isles; and Scottish Greens on the net zero proposals.<br>• Key issues were: engaging with community energy and Local Authorities and ensuring equitable provision of EV charge points including on rural roads and public access points. [E166]<br>**Central Southern England**<br>• A range of MPs were engaged on the net zero proposals representing: North Portsmouth; Brentford and Isleworth; Southhampton; East Hampshire; Wycombe; Witney & West Oxfordshire<br>• Key issue raised were: demand for EV connections was uneven across the licence area and this should be considered in network plannig and there was a need for more engagement around heat pumps [E166] |
| **Non-consumer stakeholders**<br><br>We tested our **Load strategy, outputs and costs** with a broad range of non-consumer stakeholders to understand their views on the **acceptability and bill impacts** of our Draft Business Plan via an online consultation event and surveys | • Storage and renewable Stakeholder segments noted that SSEN's Load strategy was targetted at the demand side of the net zero transition at the expense of generation, advocating clear targets for the reinforcement required to connect LCTs to the network, and for SSEN to explore storage and hydrogen as part of a wider push for net zero. [E151] [E155]<br>• This segment also urged more engagement with them to develop appropriate forecasts and to address challenges around net zero, noting that they have a target of 6GW for solar which is not consistent with our plan DFES scenario.[E155] [E167] [E151]<br>• Similarly the community energy segment urged more engagment beyond once a year to support pro-active developnent on local energy plans [E151]<br>• Engagement was sought on support for communities with grid constraints to install EV charing points [E151]<br>• EV charging points to support tourism, for example, at hotels is seen as a key issues at the local level.[E151]<br>• Support for flexible connections targets and associated engagement. [E171]<br>• Local Authorities and community energy stakeholders highlighted cases where network constraints are impediments to achieving renewable energy connections, for example schools and community buildings. [E175] The ability to connect renewable generation is seen as necessary to secure a fair, equitable and inclusive transition. [E167]<br><br>**Isle of Wight**<br>• Stakeholders noted issues related to export constraints on the Isle of Wight since approximately 2012, and potential |

| | |
|---|---|
| | curtailement of community and renewable energy connections over 3.6kW per supply phase. [E155]<br>• Some challenge to the low targets for DER in DFES 2020 (9.9MW). [E155]<br>**Active network management (ANM)**<br>• Developers need certainty for business planning in relation to active network management and constraint management zones, and this is an area they are looking for substantial progress. "The industry needs additional certainty of access rights to provide security for business planning and our ability to construct bankable schemes". [E167]<br>• Community interest stakeholder segments urged more engagement on flexibility and active network management to ensure connections can occure in a timely [E151] |
| **Consultants, Local Authorities, Community Energy Schemes, domestic customers and other segments**<br>These stakeholders were engaged by Regen through a survey and depth interviews to understand the issues and challenges that the electricity system faces -both in the transition to DSO and in enabling rapid decarbonisation to achieve net zero | • 75% of respondents were in favour of either a local authority lead or joint approach to the decarbonisation of heat planning and coordination of infrastructure, although a joint approach was the more common choice out of the two. Overall, there was very strong support for DSOs to use the outputs from local energy planning to inform network planning (84%). [E180]<br>• Respondents were clear that local political leadership is key to setting local net zero ambition, with 81% of respondents favouring a local authority lead or joint approach. [E180]<br>• A theme through the survey and interviews was stakeholder doubts as to whether DNOs are able to take an independent, transparent and ambitious approach to local energy planning and investment. [E180]<br>• Local Authority stakeholders agreed that DSOs should collaborate with other local actors to co-create a local energy plan, including providing data and technical support. Local authorities in particular strongly favoured this approach. [E180] |
| **Academics**<br>We engaged academics on our Load Investment strategy via an academic panel round table | • To ensure we maximise value when considering making investments ahead to meet net zero objectives lifecycle analysis and 'value / cost' score could be applied. [E152]<br>• To understand stranded assets and the uncertainty mechanisms design engagement with stakeholders was urged to ensure information at ground level is understood and used in network investment planning noting that the move to a more localised system for assessing and managing the network evolving to a different operating model. [E152]<br>• DER visibility and monitoring was seen as important for better grid planning but also for identifying potential sources of flexibility that can address grid constraints. [E152] |
| **ICPs/IDNOs** | • ICPs/IDNOs cited future network capacity as an issue and differential impacts between licence areas. [E171] |

| | |
|---|---|
| We engaged with these and other connections stakeholder segments on our Draft Business Plan via online workshops | |
| **Current and future employees**<br><br>We conducted audience research about our Draft Business Plan with colleagues via surveys | • Plans were seen as "good value for money" with deliverability being key to ensure customer needs wil be met. [E153] |
| **Next generation bill payers**<br><br>We engaged school-age students about the environmental aspects of our Business Plan via online focus groups | • Positive consensus around electric vehicles among future customers and experience with EVs was high. Call for charge points to be more accessible in the future inlcuding within the inner city and densely populated areas. [E158] |
| **Scottish Government (Energy and Climate Change Directorate)**<br><br>We collaborated with the Scottish Government through a series of bilaterals to identify the most appropriate Distribution Future Energy Scenario (DFES) to use as a baseline for ED2 planning | • The Scottish Government see that we have a substantial role in supporting their statutory targets. [E107]<br>• The Consumer Transformation DFES scenario is most closely aligned with the Scottish pathway to net zero, although Leading the Way is also relevant. [E107]<br>• For battery electric vehicle (EV) uptake, the expectation is that the future pathway will be between the Consumer Transformation and Leading the Way DFES scenarios. [E107]<br>• For the decarbonisation of heating, while the Consumer Transformation scenario is closest to the ambition, there is likely to be a need to go further and faster than this. Reliance on hybrid heat pumps (from Leading the Way) does not correspond with their plans. [E107]<br>• Renewable generation capacity is projected to be between Consumer Transformation and Leading the Way scenarios so the ability to flex these both up and down to meet the outturn is important. [E107]<br>• It is considered likely that there will be distribution connected electrolysis in the North of Scotland, with strong potential for areas such as Aberdeen [E059]. |

| | |
|---|---|
| **Local Authorities**<br><br>We collaborated with stakeholders via bilaterals to identify how we should identify the most appropriate DFES to use as a baseline for ED2 planning and via virtual roundtables. We then co-created LNPs by providing LAs with DFES data for their area for EVs, Heat Pumps (HPs), PV, and battery storage and asking them to assess which DFES most closely matched their plans | • Ongoing communication and collaboration between us and Local Authorities (LAs) is essential. [E063]<br>• Referencing UN Strategic Development Goals (SDGs) allows other LAs to align their principles to ours when tendering for services to support their own decarbonization projects/policy. [E063]<br>• Stakeholders agreed that defining LNP area scope by Regional Economic Partnership (in our Northern region) and Local Enterprise Partnership (in the Southern region) areas is appropriate [E063]<br>• We should consider network balancing as part of the LNP to identify opportunities for local generation. [E063]<br>• LNP development should start by reviewing Local Plans to understand where capacity needs to increase. [E063]<br>• 17% of councils responded with the evidence we sought, selecting Consumer Transformation (25% of those who responded) or Leading the Way (42% of responses) or a midpoint between these (16% of responses) scenarios in most cases. [E106]<br>• 10% of councils told us that they could not provide a response or could not do so yet. [E106]<br>• Some LAs are working in regional groups on their climate change response, for example, Oxford city, Vale of White Horse, West Oxfordshire and South Oxfordshire; BCP Council (Bournemouth, Christchurch and Poole) is producing a single plan with Dorset Council. [E106]<br>• We are maintaining an open relationship with LAs together further evidence as their plans develop. [E106] |
| **Local/community energy schemes, Consultants/Contractors, Local authorities**<br><br>We worked with Regen to engage stakeholders via separate online workshops for our North and South regions plus a follow-up survey to co-create projections for future network capacity based on a number of factors | • Engagement with Local Authorites, local energy agencies, local developers was urged including involvement in Local Energy Plans and how these should be set to meet 1.5c. [E062].<br>• Local Authorities are short in resource and time and may not be able to provide sufficient evidence for reinforcement decisions [E062].<br>• 75% of local authority representatives that participated in the local network plan survey agreed with our approach of using credible 'base' scenario for electricity demand on the network and modifying where there is strong local evidence [E062].<br>• 88% participants in the same survey felt that adjusting network plans and investment aligned with local authority plans was a fair approach given investment costs will be socialised across consumer groups and geographies [E062].<br>• Stakeholders encouraged us to collect evidence for network planning through public consultations with Community Councils [E062]. |

| | |
|---|---|
| **Community interest groups**<br><br>We conducted online roundtable discussions with small numbers of stakeholders in both licence areas to co-create Local Network plans that will allow them to deliver their climate targets, and to shape our approach to future stakeholder engagement on LNPs | • LNPs and investment should be adjusted to align with LAs' different policies and development paths for achieving net zero. [E063][E064]<br>• We should consider how gas and other energy vectors might factor into the creation of LNPs. [E063][E064]<br>• UN SDGs should be referenced in LNPs to ensure consistency at all levels. [E063][E064]<br>• Co-ordinate improvements in energy efficiency of buildings with substation reinforcement plans to achieve cost-effective investment decisions [E063][E064]. |
| **Developer/Connections representatives**<br><br>roundtable discussions with small numbers of stakeholders in both licence areas to co-create Local Network plans that will allow them to deliver their climate targets, and to shape our approach to future stakeholder engagement on LNPs | • We should work with housebuilders to promote electric heating [E063][E064]. |
| **Local Enterprise Partnerships**<br><br>roundtable discussions with small numbers of stakeholders in both licence areas to co-create Local Network plans that will allow them to deliver their climate targets, and to shape our approach to future stakeholder engagement on LNPs | • LNPs should understand the policies of different LAs, for example, with regard to electric vehicles and heat pumps [E063][E064]. |
| **Green Recovery stakeholders (local authorities, community energy schemes, DG and storage providers, housing developers, highways agencies, EV chargepoint installers)** | • Stakeholders shared plans for over 150 low-carbon demand (mainly EV chargepoints) and generation/storage projects across both of our license areas which were challenged by distribution network constraints and, in many cases, by further transmission network constraints. These projects were limited in scope to those which could be delivered in the next 2-3 years so are indicative of levels of growth rather than specific ED2 requirements. There were notable concentrations of constraint in: |

| | |
|---|---|
| We engaged with connections customers via webinar broadcasts, bilaterals and a Call for Evidence to this Government scheme which provided an additional layer of ED2 LNP insight | ○ The Outer Hebrides, Dundee and Aberdeen in the North of Scotland<br>○ Dorset and the M4/Heathrow area for demand and Wiltshire/Gloucestershire for generation in our Southern Licence Area. [E144] |
| **Consumers**<br>We tested domestic and SME customers' priorities for 15 initiatives separately for the North and South Licence Areas via a robust Willingness to Pay study, and tested our outputs with domestic customers in a Citizens Jury, and via an online survey | • Increasing the number of new low carbon heat pump connections made by the end of ED2 from 235,000 to 800,000 is a high priority for all customer segments and a very high priority for non-domestic customers in the South relative to other initiatives [E126].<br>• Increasing the number of new electric vehicle connections from a basic level of 675,000 to 1.3 million is a high priority relative to other initiatives for all customers in the South and a medium priority for those in the North [E126].<br>• Iin order to secure a fair, equitable and inclusive transition costs should be borne by those most able to afford it ie those connecting an EV or heat-pump. [E167]<br>• When asked to prioritise the output: *We will enable the timely connection of 1.3m EVs and 800,000 heat pumps based on Consumer Transformation Distribution Future Energy Scenario (DFES). Our core investment will be complemented by additional funding through uncertainty mechanisms*, the majority of customers in the south (51%) felt this was medium priority. In the north, 35% felt it was a medium priority and 35% felt it was a high priority. [E170] |

## Engagement statistics

ED2 ENGAGEMENT EVENTS

29

INSIGHTS

333

STAKEHOLDERS ENGAGED

3,481

## Stakeholder segments engaged

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CONSUMERS | Domestic customers | Customers in vulnerable situations | Transient customers | Next generation bill payers | SMEs | Major energy users | |
| CUSTOMERS | Distributed generation customers | Builders and developers | Community energy schemes | Landowners/ farmers | | | |
| POLICY MAKERS AND INFLUENCERS | Government | Research bodies, policy forums and think tanks | Media | Consumer groups | Regulators | | |
| COMMUNITIES AND LOCAL DECISION MAKERS | Local authorities | Charities | Academic institutions | Housing associations | | | |
| | Vulnerable customer representatives | LEPs | Emergency response | Healthcare | Community interest bodies | | |
| WIDER INDUSTRY AND VALUE CHAIN | DNOs | Transmission | GDNs | Water | Telecoms | IDNOs | |
| | ICPs | Consultants | Energy suppliers | EV charging | Other supply chain | Storage and renewable providers/ installers | Transport and highways agencies |
| PARTNERS AND ENABLERS | Current and future employees | Contractors | Service partners | Shareholders | Investors | Business advisers | Trade unions |

# Evidence assessment

## Engagement scoring key

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

| Overall Score | Description |
|---|---|
| 1-1.66 | Limited evidence of good event planning, methodology or data collection. Feedback provided is high level with tangential relevance to the topic. |
| 1.67-2.33 | Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful. |
| 2.34-3 | Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added. |

| Phase | Date | Event ID | Event Name | Key Stakeholder Groups | Number of stakeholders engaged | Engagement score |
|---|---|---|---|---|---|---|
| Phase 4: Testing and Acceptability | Oct-21 | E180 | Regen study: *Enabling DSO Through net zero* | Consultants, Contractors, Domestic customers, Local authorities, Storage and renewables providers/installers, Major Energy Users, Community energy schemes, Community interest groups, Vulnerable customer representatives, EV Charging Installers and manufacturers and Trade Unions | 203 | 2.5 |
| | Oct-21 | E153 | Employee Consultation Document Engagement on Draft Plan | Current and future employees | 3 | 2.3 |
| | Oct-21 | E155 | Stakeholder Consultation Document Engagement on Draft Plan | Community interest groups, storage and renewables suppliers, emergency response, healthcare and highways agencies | 19 | 2.8 |
| | Sep-21 | E171 | Engagement on Draft Connections Outputs | Housing associations, local authorities, community energy groups, distributed generation customers, consultants, ICPs and IDNOs | 67 | 1.8 |
| | Sep-21 | E151 | Consolidated Outputs and Costings Event | Contractors, Consultants, Local Authorities, National Government, Storage and Renewables suppliers, Supply Chain | 106 | 3.0 |
| | Sep-21 | E152 | Academic Panel | Academic Institutions | 7 | 3.0 |
| | Sep-21 | E156 | Draft Plan Qualitative Acceptability Testing Event | Domestic Customers | 46 | 2.5 |
| | Sep-21 | E158 | Future Consumers Event | Future Customers | 26 | 2.5 |
| | Sep-21 | E170 | Microsite survey on Costed outputs | Domestic Customers, Vulnerable Customers and Future Customers | 1,298 | 2.2 |
| | Sep-21 | E175 | Flexibility CVP Expert Event | Community Energy Schemes, Charities, Local Authorities | 31 | 2.5 |
| | Aug-21 | E166 | Corporate Affairs General Bilateral | Government, Storage and renewables providers | 25 | 2.5 |
| | Aug-21 | E162 | Digital Strategy Action Plan workshop | Academic institutions, consultants, community energy schemes, contractors, local authorities, Supply chain, storage and renewables suppliers, energy suppliers, vulnerable customer representatives | 25 | 1.8 |
| | Jul-21 | E149 | Citizens' Jury | Domestic Customers | 34 | 3.0 |
| | Jul-21 | E167 | Sustainability Strategy consultation | Vulnerable customer representative, A storage and renewables representative and Community Interest Group | 4 | 2.5 |

| Phase | Date | Event ID | Event Name | Key Stakeholder Groups | Number of stakeholders engaged | Engagement score |
|---|---|---|---|---|---|---|
| Phase 3: Business Plan Refinement | May-21 | E127 | Sustainability bilateral Thames Water | Water | 2 | 1.3 |
| | May-21 | E126 | Willingness to Pay Quantitative report | Domestic customers, customers in vulnerable situations, next generation bill payers, SMEs | 1,161 | 2.5 |
| | Mar-21 | E144 | Green Recovery Scheme Call for Evidence | EV charging, Storage and renewables, Community energy schemes, Builders and developers | 60 | 1.7 |
| | Mar-21 | E125 | Willingness to Pay Qualitative testing | Domestic customers, customers in vulnerable situations, next generation bill payers, SMEs | 54 | 2.5 |
| Phase 2: Co-creation | Jan-21 | E106 | Electricity Networks Distribution Future Energy Scenarios - Local authorities | Local authorities | 12 | 2.0 |
| | Nov-20 | E042 | Corporate affairs - Third Sector engagement | Consumer groups | 1 | 1.0 |
| | Nov-20 | E062 | Local Network Plan follow on survey | Local authorities, consultants | 8 | 2.2 |
| | Oct-20 | E041 | Corporate affairs - Political stakeholder engagement | National government | 15 | 1.0 |
| | Sep-20 | E059 | Regen Local Network Plan Workshops - North | Local authorities, consultants, community energy schemes | 67 | 3.0 |
| | Sep-20 | E060 | Regen Local Network Plan Workshops - South | Local authorities, consultants | 105 | 3.0 |
| | Sep-20 | E072 | Annual Stakeholder Workshops - North | Local authorities, vulnerable customer representatives, housing associations | 84 | 2.0 |
| | Sep-20 | E083 | Distribution Network Planning under Uncertainty | Research bodies, policy forums and think tanks | 1 | 3.0 |
| | Jun-20 | E063 | Local Network Plans Pilot - Tayside | Local authorities, LEPs | 8 | 2.3 |
| | Jun-20 | E064 | Local Network Plan Pilot - Thames | Local authorities, LEPs | 8 | 2.3 |
| | Feb-20 | E107 | Electricity Networks Distribution Future Energy Scenarios - Scottish Government | National government | 1 | 2.0 |

## Measurement of success

The table below sets out the benefits that the Load strategy and outputs will deliver to customers.

| Output | Northern Target | Southern Target | Comparison to RIIO-1 | Cost in baseline plan | Consumer benefits |
|---|---|---|---|---|---|
| Ready the network for net zero, consistent with up to 1.3m electric vehicles and up to 800,000 heat pumps connected by 2028 | EVs: c.170,000<br>HPs: c.215,000 | EVs: c.1,130,000<br>HPs: c.585,000 | 245,000 electric vehicles and 208,000 heat pump connections across both regions by end ED1 | £510.2m<br><br>Baseline load and connections-driven reinforcements with additional uncertainty mechanism funding in period | £110m carbon benefits and £120m customer financial benefits over RIIO-ED2, enabled by ensuring LCT customers are able to connect on time. |
| Ready the network for net zero, consistent with a total of 8GW of distributed energy resource (including windfarms, solar, and energy storage) connecting by 2028 | 8GW of DER across both Licence Areas | 8GW of DER across both Licence Areas | 5.6 Gigawatts of distributed energy resource connected across both regions by end ED1 | | |

Successful delivery of the LV strategy will be achieved through provision of direction to workstreams who will deliver customer benefits through ED2 outcomes. As such, success is measured through workstream metrics and outputs.

A key feature of the ED2 business plan is the implementation and roll out of LV flexibility services, as part of our transition to DSO, and so it is vital that we test and stimulate this marketplace to understand the impact that flexible operation could have on the health of our LV assets.

## Local Authority DFES engagement approach

To further enhance the scenario modelling and to allow stakeholder engagement to continue, we approached Local Authorities[60] with the results of the DFES projections to create a modified baseline scenario. The relevant data for each Local Authority (LA) was provided with a request for LAs to self-select the scenario which best represents the local (LA) view of the projection for four of the most impactful low carbon technologies.

All Local Authorities have been asked to evidence their selection, with each being assessed in accordance with an open and transparent evidence assessment framework summarised in Table 28.

- Where evidence met the required quality, the baseline DFES was subsequently adjusted (up or down).
- Where evidence did not meet the required quality threshold or where the local authority had no clear view, the forecast was defaulted to the local baseline.

Table 28 - Summary of SSEN's load-related investment in the ED2 period by reporting category

| Criteria | High Marking | Low Marking |
|---|---|---|
| **Policy/Ambition** | ++ Self consistent<br>++ Clear objectives<br>++ Overall pathways identified<br>++ Links to wider government policies.<br>++ Referenced, supported by and supportive of wider economic and social policy.<br>++ Statutory and legally binding<br>++ Aspirational but with clear policy levers and/or financial support. | ▪ No narrative available<br>▪ Exists but poorly articulated Piecemeal<br>▪ Internal contradictions<br>▪ Limited narrative for delivery.<br>▪ Does not link to wider economic / social policy.<br>Aspirational and without indication of how they will be delivered. |
| **Financial support** | ++ Financial support committed in budgetary process which has received parliamentary / council agreement.<br>+ Plans for financial support clearly laid out with pathway to delivery. | ▪ No indication of finical support.<br>Only vague indication of financial support without commitment. |
| **Delivery commitment** | ++ Formal commitment from business and third sector organisation to support delivery.<br>+ Evidence of ambition frombusiness and third sector organisation to support delivery. | ▪ Evidence that business and third sector do not support the target or policy.<br>▪ Evidence that business and third sector are not aware of the target / ambition. |

60 This occurred in January 2021 and will continue as part of Final Business Plan submission and thereafter as part of regular business-as-usual planning processes.

This approach allowed us to capture the evidence and views of our stakeholders ahead of any final decision on the ED2 expenditure plan and to create a baseline scenario detailed enough to capture potential differences in technology forecasts for each local authority. Figure 31 shows the approach.

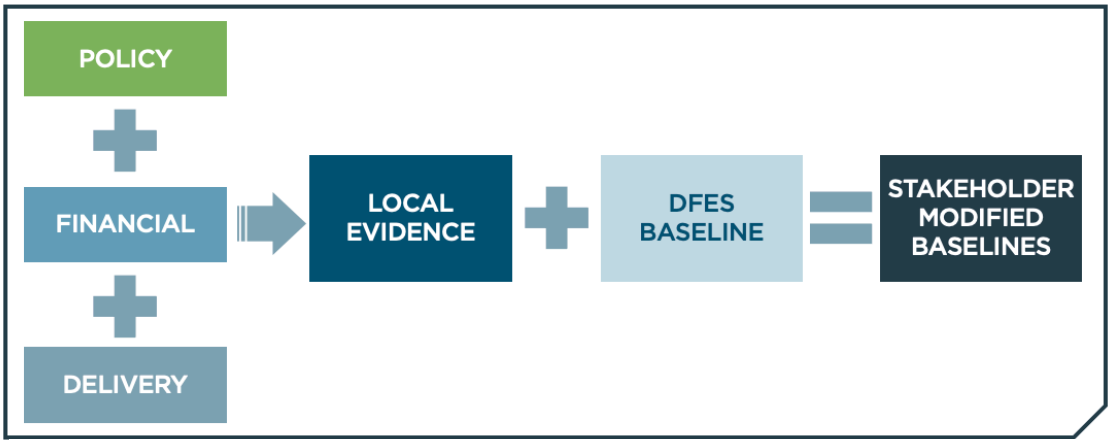


Figure 30 - Stakeholder modified baseline process

By consulting stakeholders early, creating evidence-based forecasts and communicating the results for further consultation, we have been able to create a well-founded projection of the energy changes in our licence areas.

## *LV*

- Overview: **The LV network is key to delivery of our ED2 outcomes**
- Total cost: **Included in budgets for various workstreams**

### RIIO-1 context

The LV network is expansive across both licence areas and accounts for a significant portion of the value of our regulatory asset base.

Installation of LV monitoring and smart meters is providing data to help us understand how our network is configured, how it performs, and improving our visibility to enable us to better correlate local generation with customer demand.

Data analytics is being undertaken to understand how we can make best use of available data and draw from existing knowledge.

As of June 2021, we have procured over 700 LV monitors and a rollout programme is underway to install these at sites selected based on network capacity and EV chargepoint installations.

## *Engagement synthesis*

### Stakeholder engagement

| Engagement details | Insights derived |
|---|---|
| **Academics**<br>We engaged academics via an academic panel to obtain expert stakeholder feedback on our Draft investment plans to facilitate the net zero transition and flexibility services | • The move is towards risk-incorporated network planning that reflects the inherent uncertainty, emphasizing that flexibility will only play an important role if it is cost efficient and when DNOs have visibility over risks. All of this will require much more coordination with key stakeholders and advances in LV network monitoring. [E152] |
| **Non-consumer stakeholders**<br>We tested our **Load strategy, outputs and costs** with a broad range of non-consumer stakeholders to understand their views on the **acceptability and bill impacts** of our Draft Business Plan via an online consultation event and surveys | • Taking up from the conversation around net zero, storage and renewables stakeholders advocated greater ambition in terms of workforce, taking on more apprentices and trained staff to prepare for a deluge of information and data coming from greater monitoring on the LV network. [E151] |
| **Other supply chain** | • Stakeholders want us to continue with their current annual targets for monitors as they are achievable [E057]. |

| Stakeholder engagement | |
|---|---|
| **Engagement details** | **Insights derived** |
| We conducted audience research with these stakeholders via an online workshop to co-create our LV monitoring approach and procurement process, and via a survey following up a general supply chain engagement event | • Stakeholders were at best ambivalent about using 'transformer capacity utilisation' and 'feeder capacity utilisation' as a basis for monitoring installation, instead suggesting a number of alternative measures including power quality and fault patterns/frequency [E057].<br>• In addition to using LV monitoring to inform fault dispatch, stakeholders suggested that we should use 'unbalance', 'real time EV load', 'phase identification', 'real time data for fault prediction', and 'PV (or V2G/BESS) backfeed' [E057].<br>• A majority of stakeholders would prefer us to use a procurement approach which separated sourcing for LV monitoring device hardware from sourcing for software analytics platforms, and they would be happy to supply just one of these [E057].<br>• A minority of stakeholders highlighted that some solutions did not fit well with our preferred iHost interface, which discouraged some from tendering to supply LV monitoring equipment, but most stated that it did not present a problem for their solution and did not discourage them from tendering [E057].<br>• When asked which of the 'New for ED2' categories suppliers believed is the most important in achieving an effective future network, 'low voltage monitoring' was one of the options stakeholders most commonly selected [E066]. |
| **Distributed generation customers, local authorities**<br>We engaged with stakeholders to co-create uncertainty mechanisms via a virtual roundtable | • A data-driven approach was seen as absolutely crucial to rolling out EV chargers, as different parts of our network would need different levels of reinforcement, and therefore large amounts of LV monitoring would be needed prior to any infrastructure roll-out or network reinforcement in order to ascertain how much reinforcement would be needed in each local area and where it would need to go [E068].<br>• Stakeholders were concerned with the monitoring of low voltage (LV) networks, particularly with the predicted increase of electric vehicles (EVs), as their chargers would be connected to LV networks – they urged us to address any results from LV network monitoring and ensure that it was intertwined with other UM approaches, such as strategic investment [E068]. |

## Engagement statistics

**ED2 ENGAGEMENT EVENTS**

**7**

**INSIGHTS**

**19**

**STAKEHOLDERS ENGAGED**

**270**

## Stakeholder segments engaged

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CONSUMERS | Domestic customers | Customers in vulnerable situations | Transient customers | Next generation bill payers | SMEs | Major energy users | |
| CUSTOMERS | Distributed generation customers | Builders and developers | Community energy schemes | Landowners/ farmers | | | |
| POLICY MAKERS AND INFLUENCERS | Government | Research bodies, policy forums and think tanks | Media | Consumer groups | Regulators | | |
| COMMUNITIES AND LOCAL DECISION MAKERS | Local authorities | Charities | Academic institutions | Housing associations | | | |
| | Vulnerable customer representatives | LEPs | Emergency response | Healthcare | Community interest bodies | | |
| WIDER INDUSTRY AND VALUE CHAIN | DNOs | Transmission | GDNs | Water | Telecoms | IDNOs | |
| | ICPs | Consultants | Energy suppliers | EV charging | Other supply chain | Storage and renewable providers/ installers | Transport and highways agencies |
| PARTNERS AND ENABLERS | Current and future employees | Contractors | Service partners | Shareholders | Investors | Business advisers | Trade unions |

## Evidence assessment

### Engagement scoring key

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

| Overall score | Description |
|---|---|
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| 1.67-2.33 | Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful. |
| 2.34-3 | Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added. |

| Phase | Date | Event ID | Event name | Key stakeholder groups | Number of stakeholders engaged | Engagement score |
|---|---|---|---|---|---|---|
| Phase 4: Testing and Acceptability | Sep-21 | E151 | Consolidated Outputs and Costings Event | Contractors, Consultants, Local Authorities, National Government, Storage and Renewables suppliers, Supply Chain | 106 | 2.5 |
| | Sep-21 | E152 | Academic Panel | Academic Institutions | 7 | 2.5 |
| | Sep-21 | E176 | Citizens Advice report on DNO Draft ED2 Business Plans | Consumer groups | 1 | 2.0 |
| | Aug-21 | E162 | Digital Strategy Action Plan workshop | Academic institutions, consultants, community energy schemes, contractors, local authorities, Supply chain, storage and renewables suppliers, energy suppliers, vulnerable customer representatives | 25 | 1.8 |
| Phase 2: Co-creation | Mar-21 | E068 | UM south round table | Distributed generation customers, local authorities | 10 | 2.0 |
| | Nov-20 | E066 | Supply chain engagement launch event follow on survey | Other supply chain | 100 | 2.0 |
| | Oct-20 | E057 | LV monitoring supply chain workshop | Other supply chain, Transmission, Consultants, Service partners | 21 | 2.5 |

# Appendix C LOAD MANAGED AREAS (LMA)

Load Managed Areas (LMA) in SHEPD cover approximately 87,000 customers, spread right across the geographic licence area, including the islands and many densely populated towns and cities. LMA reduce the maximum demand on circuits at all voltage levels and at substations by effectively smoothing demand over the 24-hour period. Currently, space heating and water heating load are independently controlled at different times during day and night via Long Wave Radio Tele-Switching (RTS).

## Background and context

It was originally planned that suppliers replace all RTS meters with SMART meters by April 2020. Ofgem agreed under DCP 326 to replace RTS with pre-programmed SMART meters. This was not achieved, and targets were missed by suppliers and the smart meter programme. The need for additional controls on SMART meters contributed to the delays.

LMA is a historical mechanism allowing the use of demand-side management to support the connection of large amounts of space and water heating without triggering costly network reinforcement in the SHEPD licence area. These emerged in the 1970s when companies were integrated (generation, supply and networks) and were keen to maximise benefits of cheaper overnight wholesale (e.g. nuclear) electricity while also respecting the physical limitations of the network. It was also a time in North of Scotland when there was a push to get customers onto electric storage heating and off costly oil, peat, and coal – especially for the many in Scotland who could not access the gas network.

LMA are becoming increasingly misaligned with the direction of travel for electricity distribution in the UK on a number of counts:

1. Reliance on static tariffs designed for the nuclear era rather than dynamic tariffs emerging to respond to flexibility market and intermittent renewable generation;
2. Provision of a level of flexibility service with no ongoing reward to the customer providing the flexibility;
3. Representing an additional barrier to customers switching supplier by effectively locking customers into specific tariffs, therefore driving-up energy costs[61];
4. Creation of a two-tier customer experience which could be interpreted as a 'post code lottery'; and
5. Undermines the opportunity for market provision of alternative flexible solutions, and consideration of any potential wider Whole Systems benefits to the national system or wholesale energy markets.

These factors and the desire for greater customer choice on tariffs, supplier switching and the continual drive to alleviate fuel poverty and customers in vulnerable situations, all provide for a compelling case for the removal of LMA.

[61] As identified by Citizens Advice Scotland.

*We seek to start the process of removing LMA restrictions from our network in ED2 through migration to a flexibility services-based approach. This will be aligned to network investment needed for uptake of low carbon technology, the aim being to remove all restrictions during the ED3 period.*

### ED2 priority will be to use flexibility as a first solution for LMA removal

LMA were introduced as an alternative to traditional reinforcement. LMA is a form of flexible solution for the provision of capacity but, unlike our arrangement for Constraint-Managed Zones (CMZ), LMA provides no ongoing reward for the provider of the flexibility. Instead LMA inadvertently penalises customers by obstructing access to the competitive supply market and potentially locking LMA customers into more expensive tariffs. We therefore believe that market solutions should be the first choice for enabling the lifting of customer LMA restrictions and the promotion of market-based flexibility services. Removal of LMA constraints through conventional constructed solutions (iron and copper) should be a last resort unless it is shown to be more economic through alignment with other drivers such as load growth or condition-based replacement, for example.

Our short-term approach is to maintain switching patterns using smart metering via suppliers, as per current DCUSA obligation. The diversity this creates will need to continue in some form until LMA restrictions are lifted. In parallel, we will initiate innovation trials to help refine and test the suitability of third-party flexibility solutions at the domestic (low voltage network) level.

Our approach in ED2 will be to seek to use market flexibility services to replace LMA mandated switching patterns – including activities to define, develop and stimulate the market – alongside, and in accordance with, development and facilitation of flexibility markets to support DSO. In order to achieve this, we require flexibility services to be provided by LV domestic customers. These services do not exist at present. Success will be dependent on our ability to stimulate the market and on third party organisations, such as electricity suppliers and product developers, to help support development of the flexibility services required. This process will be assisted by our proposed Local and Community Market Stimulation CVP and supported by our innovation programme.

Solutions to provide additional capacity to support the uptake of LCT will be co-optimised with those to remove LMA restrictions – using the principle of 'flexibility first'. We will also ensure that all/any other reinforcement or flexibility procurement for other (non-LCT) needs or requirements provides for LMA removal, as a matter of course.

In ED2 we will therefore actively pursue flexible solutions which deliver value for money for customers on a Whole Systems basis, taking full account of the wider costs and benefits. We will initially signpost our flexibility requirements based on our understanding of the network constraint parameters represented by the existing LMA arrangements. This will allow flexibility providers time to design appropriate services including technologies such as flexible heat pumps, efficiency/flexibility packages and tariffs. As we understand network requirements in more detail – through LV monitoring and analysis – we expect to be able to procure such services accurately, delivering benefits.

Our ED2 HV and LV load-related expenditure proposals take full account of a range of different sources of flexibility, including domestic smart EV charging, domestic vehicle-to-grid; flexible heat from domestic heat pumps; the expected uptake in time-of-use tariffs, and a variety of energy efficiency interventions.

Our success in using flexibility services as the primary means of removing LMA will require significant development of the LV domestic flexibility market, and the identification of business models that work for all. Many aspects of this are beyond our direct control. We will report progress throughout ED2 and retain options for more conventional solutions if all reasonable alternatives have been exhausted.

A full and detailed account of our methodology for assessing the benefits of flexibility at HV and LV is provided in our DSO Annex[62].

### One solution to support LCT uptake (net zero) requirements and LMA removal

There will be a significant overlap between capacity solutions for LCT uptake and the potential capacity needed for removal of LMA. In considering the options to support LCT uptake we will integrate the capacity requirements associated with removal of LMA restrictions. We will apply our standard 'flexibility first' approach to the resulting composite demand profile to help understand the role that flexibility should take to optimise costs and benefits in relevant parts of our network.

At EHV, we have ensured that any planned reinforcement of primary substations (33kV/11kV) and circuits proposed as part of the ED2 Business Plan to accommodate low-carbon technology (LCT) uptake also supports the removal of switching pattern restrictions on all LMA customers supplied from that substation. We have also analysed all other EHV circuits and primary substations and identified the additional flexibility/reinforcement requirements needed to accommodate LMA restriction removal. These have been considered within the ED2 uncertainty mechanisms and our long-term plan to lift all LMA restrictions in ED3.

At HV and LV we are extending the data-led 'hot-spot' analysis of all HV and LV circuits using the approach developed for LCT uptake in the ED2 Business Plan in order to ensure co-optimise additional capacity solutions across LCT and LMA needs – with a focus on procuring flexible solutions first. As for EHV, we have also considered the wider impact on the HV and LV network of lifting the LMA completely, to ensure alignment with the ED2 uncertainty mechanism and plans for ED2 and beyond.

It is anticipated that the load-related investment anticipated in ED2 will ease or lift around 30% of the LMA restrictions by the end of the ED2 period, with the potential for up to approximately 50% of restrictions lifted if higher levels of LCT materialise (additional uncertainty mechanism funding). This will be subject to detailed analysis of voltage and back-feed arrangements, once the flexibility and reinforcement requirements are known, with the final decision driven by cost benefit analysis. Particular care will be taken where diesel generation is presently used to provide back-up supply to ensure that a Whole Systems approach is considered with flexibility used to provide opportunities for alternative, net zero, generation to secure customer supply.

### An opportunity to focus enhanced LV monitoring and deliver additional customer value

To ensure the long-term economic and efficient lifting of LMA restrictions, a key part of our effort prior to, and during, ED2 will be to validate and calibrate our data-led analysis of LMA constraints on the LV (and HV) networks. This will enable a better understanding of the capacity intervention requirements – be it conventional or flexibility service – and customer behaviour, associated with end-to-end removal of LMA restrictions in a given community area.

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62 DSO Strategy, Annex 11.1, Appendix G 'HV and LV Flexibility Methodology'.

In line with our Network Visibility Strategy we will install LV monitoring and expect to remove up to 1,900 customers from the LMA register by reinforcing parts of the network associated with Constable Street Primary Substation in Dundee and Ormlie Primary Substation in Thurso. This will be funded through 'Green Recovery' and will allow us to hone our methods and allow flexibility service providers to understand the requirements. Combining this strategy with the current industry LMA solution, the existing planned investment due to LCT and our plans to expand network analytics and modelling will, we believe, allow us to remove LMA restrictions more rapidly and inform our investment decisions in ED2 and beyond.

We will also use the opportunity to investigate the options for flexibility, the level of response we get from customers towards those options and specification of the *need* for future flexibility services. As part of our digital investment strategy, we will develop the tools required to monitor and administer these in the short, medium and long-term.

### Methodology for establishing the justification of this proposal

The case made above for removal of LMAs focusses on a number of qualitative and quantitative benefits, the suggested methodology for assessing these can be found in Table 29.

Table 29 – Methodology for assessing benefits of LMA removal

| Types | Benefit Title | Description | Method of quantification |
|---|---|---|---|
| Customer saving | More competitive supplier energy costs (through avoiding tariff limitations) | Customers of Total Heating, Total control (THTC) are locked into tariffs. The LMA limits the tariffs that suppliers can offer and there is no compensation offered. | Draw on work being undertaken by Citizens Advice Scotland (CAS) to inform the determination of customer financial costs and benefits. This will include an assessment of the proportion of these customers that are classed as 'fuel poor'. |
| Customer saving | New revenue from flexibility service provision products | Customers will be free to participate in arrangements that may provide reward for providing flexibility for wider Whole Systems benefits to the national system or wholesale energy market (via their supplier). This is particularly relevant in that most RTS customers have thermal storage installed. | Seek third-party assessment of potential customer benefits. |
| SSEN reputational | Reputational Damage | LMA will increasingly be recognised as a means for DNOs to acquire flexibility without paying for it. This conflicts with a number of directives including the Clean Energy Package and as such should to be tested against a market-based alternative. | Assessment of potential compliance risk.<br>Explore potential alternative opportunities for rewarding customers for delivering flex value. |
| SSEN saving/customer saving (indirectly) | Deferred network reinforcement | Currently SSEN pays the largest proportion of costs for the maintenance of the Low Wave RTS system as the main benefactor of the system. | The existing RTS system although controllable will require replacement as the equipment has become obsolete and it is no longer possible/cost effective to maintain. Through the cost effective and improved granularity that we can obtain from Flex Services (all |

| Types | Benefit Title | Description | Method of quantification |
|---|---|---|---|
| | | | customers, not just RTS) we have the possibility to get more headroom from our Network assets through flexibility. |
| Internal Saving | RTS Optimisation and cost reduction | The operation of RTS in LMAs has always been problematic with associated overhead and operation costs | Removal of costs associated with RTS (although unlikely to cover cost of procuring flexibility). |
| | | | |
| CI/CML back-feed resilience | Circuit-specific back-feed load management | Increased opportunity to use flex at time of fault to enable use of (partial) back-feeds (e.g. Grudie Bridge, Kilmelford) to provide required levels of security (e.g. n-1) | Undertake a study to quantify the value on a probabilistic basis of flexing demand at times of fault. |

## Regulatory treatment in ED2

A large proportion of LMA restriction is expected to be removed in ED2 through our minimum proposed load-related investment programme and through additional UM-funded strategic investment associated with the uptake of LCT. Any LMA-related expenditure over and above this will be informed by reference to CBA which captures the Whole Systems cost of continuing LMA, including the assessment of any associated customer detriment and broader societal and community costs. Finally, the end of ED3 will mark the time backstop for complete removal of all (imposed) LMA constraints across SHEPD licence area.

A summary of our six [6] element hierarchy of strategic solutions for the phased removal of LMA restrictions is set out in Table 30.

Table 30 – Summary of proposed approach to LMA removal.

| | |
|---|---|
| Short-term (ED1/ED2) | 1. Maintain switching patterns using smart metering via suppliers (as per current DCUSA obligation) and initiate LMA focussed innovation |
| Medium-term (ED2) | 2. Use of market flexibility services to replace LMA mandated switching patterns and phase our smart metering switching patterns where market is viable.<br>3. Co-optimise with additional capacity solutions (LCT) for the uptake of LCT – using flex first principles<br>4. Ensure that any other network expenditure (LRE and NLRE) or flex procurement for other (non-LCT) needs or requirements provides for LMA removal<br>5. Partially maintain switching patterns using smart metering via suppliers (as per current DCUSA obligation) |
| Longer-term (ED3) | 6. End of ED3 as a time backstop for removal of all LMA constraints |

### Next Steps

In preparation for the removal of LMAs we have set up a Project Steering Board to manage the process starting with determination of the flexibility requirements, design of the flexibility Services requirements, engagement with potential flex providers (including suppliers), preparation of the flex tender exercise, LCT network investment alignment.

Where required we will consider the use of NIA funding to resolve any residual barriers to the LMA removal programme.

# Appendix D LOW VOLTAGE STRATEGY

# 1. WHY DO WE NEED AN LV NETWORK STRATEGY?

## 1.1. OUR STRATEGIC OUTCOMES

At Scottish & Southern Electricity Networks (SSEN) our stated purpose is that *we power communities to thrive today and create a net zero tomorrow*.

To support our purpose, we have set out the following Strategic Outcomes:

- Accelerated progress towards a net zero world
- A valued and trusted service for our customers and communities
- A safe, resilient, and responsive network
- A positive impact on society

The Low Voltage (LV) network is strategically important for reaching net zero and will be a focal point of investment in ED2 and into ED3 and beyond. The ongoing decarbonisation efforts of the energy industry will see enormous changes on LV networks, particularly as organisations work together in a Whole Systems way to electrify heat and transport down to the domestic level. Section 3.2 outlines some of the key changes expected on our networks over the next decade.

We have relatively poor visibility (in terms of data, information and understanding) of our LV networks, compared to what we know about our HV and EHV networks. Our LV networks were designed and built to conservative planning standards assuming unidirectional power flows, specifically to ensure adequate capacity for all customers, meaning that visibility was not necessary nor a high priority.

With a fundamental shift in demand patterns underway, and more small-scale generation connecting locally, visibility is becoming increasingly important. We need to know much more about our LV network if we are to deliver on our purpose and strategic outcomes. Improved visibility will allow us to manage voltages and power flows, and to perform swift remedial action to improve resilience and invest efficiently.

The transition to Distribution System Operator (DSO) and increased use of flexibility services at LV will also see more active participation from a broader range of stakeholders and it is vital that the right systems are in place to enable this Whole Systems working.

## 1.2. PURPOSE OF THE DOCUMENT

### 1.2.1. WHAT IT IS

This LV Strategy document sets out the overarching strategy to develop our LV network. It aims to ensure we continue to deliver a safe, reliable, cost-effective service to our customers, while at the same time enabling the electrification of heat, transport and facilitating active and equitable customer participation throughout our licence areas.

It is intended to offer guidance and strategic direction across the range of business areas within SSEN Distribution to ensure that activity and development on the LV network is coordinated and aligns with our purpose and our LV Strategic Outcomes.

The LV Strategy is complementary to our existing strategies and policies and will also form part of our ED2 submission to demonstrate and support our proposed investment in the LV network for the upcoming price control period.

### 1.2.2. WHAT IT ISN'T

The document is not intended to provide any specific technical, commercial or policy details on the LV network or advise on how specific initiatives or projects should be managed or delivered. SSEN policy documents can be accessed in the Document Management System.

## 1.3. TIMESCALES

The core of this strategy document sets out what we want to achieve, and how we plan to achieve it, over the period from now until 2030. The document will be updated periodically to keep it relevant.

# 2.WHAT INFLUENCES OUR LV STRATEGY?

## 2.1. EXTERNAL INFLUENCES

### 2.1.1. GOVERNMENT POLICY AND AMBITION

Government-level ambition, targets and legislation have an impact on the electricity sector, and they can have a huge influence on the timescales of change. These ambitions and targets also drive the need for us to work collaboratively with others across the whole electricity system (e.g. with gas companies to decarbonise heat), and with stakeholders in other sectors (e.g. working with the transport sector to deliver EV strategies).

A good example of government policy which will have a significant impact on the LV network is the ban of the sale of petrol and diesel vehicles by 2030[63]. This presents a challenging timeframe for SSEN, however, we are addressing this challenge in our ED2 business plan, where we set out our plan to work with the transport sector to prepare our LV networks to accommodate a large number of EV charge points and devise innovative solutions to enable this transition.

The Ten Point Plan for a Green Industrial Revolution[64] and the subsequent 2020 Energy White Paper "Powering our net zero Future" also set out ambitious targets across generation, demand, digitalisation, and customer engagement. These documents will feed into how SSEN strategic development is undertaken, and how we work with others to support the delivery of ambitions and targets across the whole electricity system.

Furthermore, there are both existing and forthcoming legislative requirements that influence our LV Strategy.

### 2.1.2. REGULATORY PRICE CONTROL

The Ofgem price controls influence how DNOs plan and invest in their networks, and the upcoming RIIO-ED2 (Revenue = Incentives + Innovation + Outputs) price control will determine how we can and should invest in the LV network throughout the coming decades. We believe that the forthcoming price control will be one that will see significant change and investment on the LV networks. The process of preparing our RIIO-ED2 ("ED2") business plan has already highlighted numerous opportunities and challenges that must be addressed to ensure prudent and efficient expenditure decisions are made in respect of owning and operating our LV Network.

### 2.1.3. THE DSO TRANSITION AND THE USE OF FLEXIBILITY SERVICES.

The transition to a Distribution System Operator (DSO) is already underway. We set out our plan for Our Transition to DSO in 2017 and our plan on Delivering DSO in 2019[65]. The transition is part of a coordinated Whole Systems effort from all UK Distribution Network Operators (DNOs), supported by the Energy Networks Association (ENA) and the Open Networks project[66].

This transition will see unprecedented changes in how distribution network companies will operate and manage the LV network, and in how our customers will interact with the network and with our business.

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63 https://www.gov.uk/government/news/government-takes-historic-step-towards-net zero-with-end-of-sale-of-new-petrol-and-diesel-cars-by-2030

64 https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution/title

65 https://www.ssen.co.uk/SmarterElectricity/

66 https://www.energynetworks.org/creating-tomorrows-networks/open-networks

The transition to net zero, and the associated network challenges, represent a key driving force for innovation and flexibility. It will ultimately change the traditional operating philosophy of distribution networks, and the way distribution networks work with others – for example, through our Whole Systems strategy and approach[67]. This in turn will allow electricity distribution businesses and customers to actively respond to situations through efficient use of existing network assets and a variety of new technologies and services.

### 2.1.4. WIDER INNOVATION AND TECHNOLOGICAL DEVELOPMENTS

The energy transition is bringing about significant changes across the energy sector. We are seeing rapid technology advancements (such as in battery technologies) and the development of innovative solutions to emerging challenges. The challenges we face are not unique to SSEN, and there is a real opportunity for distribution network companies to work together, and to work with stakeholders across the energy and other sectors (e.g. local authorities, transport, water, telecoms) in a Whole Systems way to share knowledge and expertise to solve problems. Further details on our Whole Systems strategy are provided in our *Enabling Whole Systems Solutions* business plan annex (12.1).

In Great Britain (GB), the Ofgem-funded innovation projects (Low Carbon Networks Fund (LCNF), Network Innovation Competition (NIC) and Network Innovation Allowance (NIA) are geared towards collaboration and knowledge sharing. These projects have already yielded excellent collaborative relationships and workable solutions to challenges that can be applied across networks.

It is important for us to maintain our focus on innovation and work with other DNOs and industry partners to develop solutions and exercise best practice in adopting new technologies.

## 2.2.INTERNAL INFLUENCES

### 2.2.1. NETWORK TOPOLOGY

This LV Strategy applies to both the Southern Electric Power Distribution (SEPD) and Scottish Hydro Power Distribution (SHEPD) licence areas.

The SEPD area is densely populated, while the SHEPD area stretches over a vast and varied geographical area.

There is more extensive LV overhead network in the SHEPD region while the LV network in the SEPD region consists primarily of underground cables. The approach to managing and maintaining these assets is fundamentally different.

The LV Strategy applies to both licence areas.

### 2.2.2. LEGACY NETWORK ASSETS

The characteristics and challenges associated with the existing network will significantly influence the strategy needed to deliver the medium-term strategic outcome.

There are a number of issues and challenges with existing assets which influence how the LV network needs to change and evolve in future. This includes risks associated with known and recurring defects and faults associated with certain cable types (e.g. CONSAC, as further detaied in our Safety and Resilience

[67] ED2 Final Business Plan, Chapter 12 and Annex 12.1.

Annex 7.1), rating limitations associated with looped services, low capacity (e.g. 15kVA) pole-mounted distribution transformers – as well as legacy issued associated with phase balancing.

### 2.2.3. STRATEGIC OUTCOMES

The business Strategic Outcomes have shaped and influenced this LV Strategy.

The outcomes are particularly relevant for LV where interaction with customers (and the public overall) is most visible. This presents a real opportunity for SSEN to become the *valued and trusted service provider* making a *positive impact on society* by providing *a safe and resilient network* as we *progress towards a net zero World*.

The key will be working with customers and communities and ensuring they are part of the journey.

### 2.2.4. ALIGNMENT WITH WIDER SSEN STRATEGIES

The LV Strategy aligns with other SSEN business strategies, all of which are working towards the same Strategic Outcomes. Below is a list of some of the key strategies that the LV Strategy will complement.

- *ED2 Load-Related Strategy*. Alignment with overarching load-related strategy is key to ensure support and facilitation of net zero in a way that delivers immediate benefits and long-term value to customers.
- *ED2 Non-Load/Asset Strategy*. Close linkages with asset strategy will ensure LV asset maintenance and reinforcement is undertaken according to asset strategy (unique to asset type).
- *Connections Strategy.* Consistency and alignment with cost-apportioned reinforcement and LCT strategic investment in general (no double-counting) will be critical at LV.
- *DSO Strategy*. DSO functionality and the use of Flexibility Services and Flexible connections at LV will be hugely important, and likely very valuable and so the LV Strategy must be complementary to ensure that LV network is not a blocker for the development of flexibility markets and other non-conventional solutions at LV.
- *Strategic Asset Management Plan (*SAMP*)*
- *Digitalisation Strategy*. This will support the increased monitoring and control required at LV, as well as the roll out of DSO capability.
- *Network Visibility Strategy.* The Network Visibility Strategy set out our pathway to 100% visibility of power flows (on all asset levels of our network) through the installation of LV monitoring on almost one fifth (19%) of our secondary ground-mounted substations and advanced analytics.
- *Whole Systems Strategy.* Alignment of the LV Strategy with SSEN's approach for Whole Systems working in ED2 will enable better collaboration, improved efficiencies, and reduced duplication in delivering our LV strategy and working toward net zero. It also enables us to share knowledge and learnings with others, and for us to draw on external expertise to deliver our LV Strategy.
- *Losses Strategy*. Alignment here is crucial to ensure work on the LV network is carried out in accordance with the losses strategy to optimise network losses e.g. asset replacement with minimum sizes, and drive efficiency.
- *Sustainability Strategy*. Overall alignment on wider sustainability and net zero targets.

- *Innovation Strategy*. Supporting the transition of innovation projects into business as usual, specifically those seeking to improve LV network visibility and performance, will be a huge enabler for accelerated progress on LV network improvements.
- *Data Strategy.* Strategically driving a programme of data quality management enabling our data to drive efficiencies and support best practice when working on the LV Network.

# 3.OUR LV NETWORK

## 3.1. WHAT IT LOOKS LIKE NOW

Headline statistics associated with our LV network are provided in Figure 27.

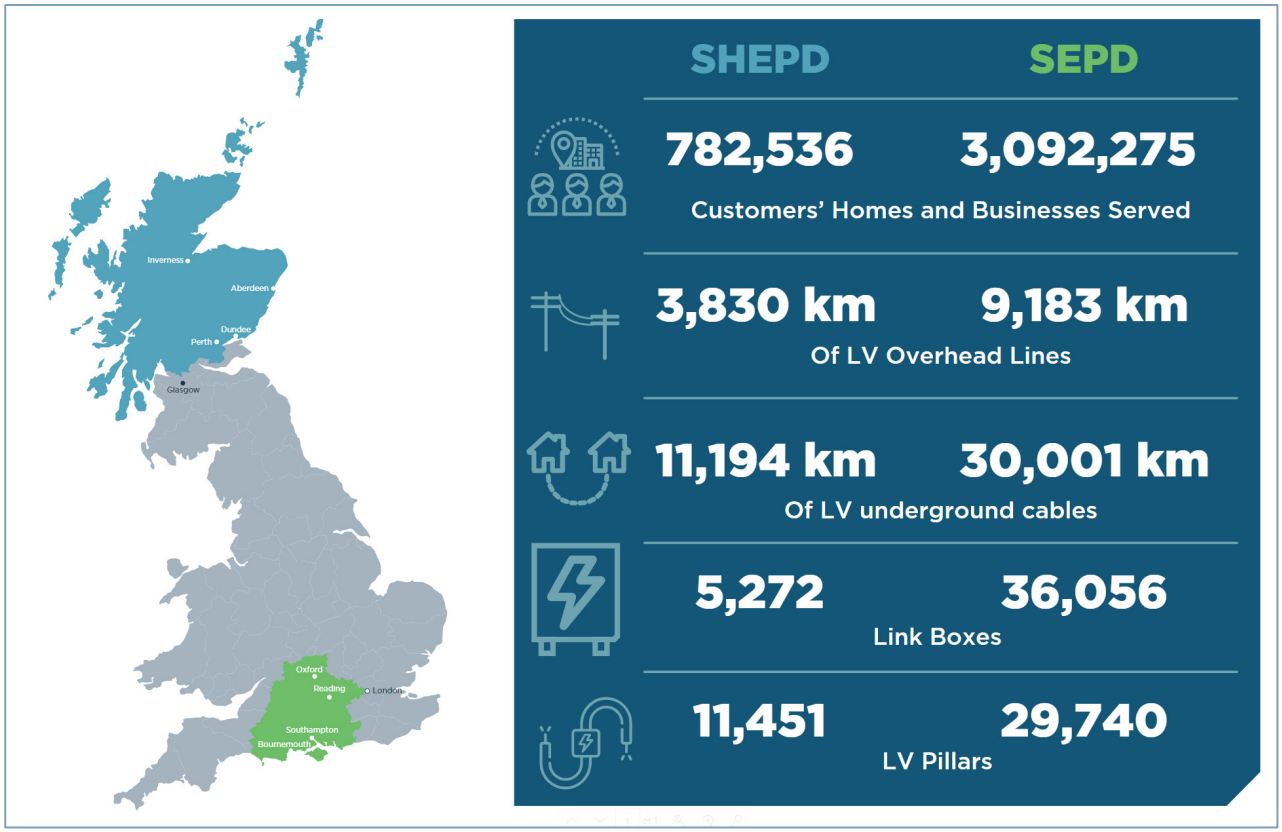


Figure 31 – SSEN's LV Network

The LV network is expansive across both licence areas and accounts for a significant portion of the value of SSEN's regulatory asset base.

## 3.2.DEVELOPMENTS TO 2030

Since 2018, SSEN has engaged Regen to support in the development of Distribution Future Energy Scenarios (DFES). These scenarios identify credible future pathways for our distribution business and to highlight the trends in energy generation and demand out to 2050.

According to our latest analysis[68][69] across all DFES scenarios it is expected that there will be in excess of 4.3 million EVs connected in SEPD by the 2040s and over 800,000 in SHEPD within the same time period.

The UK Government's commitment to stop the sale of petrol and diesel engine vehicles by 2030 is a significant contributing factor.

The switch of domestic and non-domestic heating to electric heat pumps is less certain, however there is still expected to be substantial uptake across both licence areas (potentially 1.7 million properties in SEPD and c. 700,000 properties in SHEPD) under some credible scenarios.

68 Distribution Future Energy Scenarios 2020 Southern England licence area Results and Methodology Report, Dec 2020.
69 Distribution Future Energy Scenarios 2020 North of Scotland licence area Results and Methodology Report, Dec 2020.

In addition, some 600,000 new houses are expected to be built in SEPD and around 112,000 in SHEPD across all scenarios by 2050.

As of the start of 2021, there were approximately 900,000 smart meters installed across the SEPD and SHEPD licence areas, against a target of around 3.7 million (i.e. every household). Industry view is that the benefits of smart meters and their accompanying data can start to be realised when a 60-70% penetration is reached (2.2 – 2.6 million). A 95% penetration roll-out deadline for smart meters has been set by BEIS indicating that at least 3.5 million smart meters will be installed on SSEN's networks by 2024.

From a network perspective, the uptake of new technologies (both generation and demand) and the electrification of heat and transport translates to a significant shift in daily demand patterns and an overall increase in maximum demand. Recognising that, it is an extremely difficult (and somewhat unnecessary) task to reinforce large parts of the LV network to provide enough capacity for this additional demand, opportunities to develop and deploy alternative smart techniques, such as flexibility services and demand side response (DSR), are actively pursued.

Flexibility would see customers participate in network operation and management by providing services to the DSO. This can be via smart Electric Vehicle (EV) chargers, or commercial agreements and tariffs to reduce demand during certain periods of time. The options for flexibility are wide and varied; there could be any number of interactions occurring at once to ensure the network is kept within its safe operational limits.

The anticipated Low Carbon Technology (LCT) uptake presents a significant challenge for us and our LV network.

The LV network comprises a significant proportion of old and ageing assets. These assets have been successfully operating in a passive manner (unidirectional power flows to serve customer demand) for decades. With the energy transition, and the changes that accompany it, we are now requiring our LV Network to operate in new ways, accommodating high levels of demand, bi-directional power flows and enablement and support for flexibility services. Our LV Network was not originally designed to deliver the types of load profiles and duty cycles that are beginning to emerge.

It must be acknowledged that there is a lot of work to be done to ensure the network is fit for purpose, and that this can realistically only be achieved through coordinated and incremental progression.

## 3.3. HOW TO GET TO WHERE WE WANT TO BE?

### 3.3.1. WHERE DO WE WANT TO BE?

We must continue to provide a safe, reliable, and cost-effective service to our customers while managing the significant changes that are expected over the coming years.

This means we have an obligation to enable our customers to connect new technology and interact with the network and the marketplace, all while minimising disruptions and consistently improving our customer service provision.

Gaining a better understanding our existing LV assets to support a prudent and efficient asset management capability is critically important. We must ensure that we optimise the costs and outputs of owning and operating our LV network assets – this includes careful and effective management of asset deterioration, required reliability levels, legislation change, climate adaptation, etc.

Significantly increased levels of customer engagement will be an important feature of operating the electricity distribution network in future. Openness and transparency will be key to facilitating a smooth transition.

From a customer service perspective, we want to be anticipating the needs of our customers, ensuring that the network capacity and the information they need is available at the right time. Our vision is that we will 'pre-assess' customers' LV services so that we can provide individual homes, or streets, with an 'LCT Readiness' status. All this will pro-actively promote LCT uptake and ensure that SSEN is not a barrier to net zero.

### 3.3.2. WHAT ARE THE BIGGEST CHALLENGES?

Some of the key challenges on the LV network are rooted in the **visibility** (of data and information) and better understanding of the **connectivity** of the network to an individual phase and individual home level itself. This is in addition to the health and condition issues associated with an ageing LV network.

The challenge and opportunity associated with visibility and connectivity are omnipresent, but they do vary with the business areas, for example:

- Operational staff working on the physical network can experience delays on site while they locate the correct cable in a trench to address a fault. This impacts Customer Minutes Lost (CML).
- The system planning and investment teams must make assumptions on long-term, potentially high-value, investment requirements. Sometimes based on limited data or evidence which will be subject to rigorous scrutiny from stakeholders and Ofgem.

There are some important challenges, such as the need to ensure that individual sub-strategies – such as that for tree cutting for example - align and coordinate in a way that delivers the target strategic outcomes for the LV network. Ensuring a single source of truth for data is also a critically important building-block for the future success of our LV network.

The LV Strategy seeks to address many of these challenges holistically and as efficiently as possible.

### 3.3.3. WHAT ARE WE ALREADY DOING TO OVERCOME THESE CHALLENGES?

There is already a lot of activity being undertaken on the LV network to address some of the key challenges.

Installation of LV monitoring[70] and smart meters is providing data to help us understand how our network is configured, how it performs, and improving our visibility to enable us to better correlate local generation with customer demand. LV fault management devices are being deployed to improve our response to LV faults and reduce CI/CMLs.

Data analytics is being undertaken to understand how we can make best use of available data and drawn from existing knowledge. We are already successfully using robust data science techniques to fill key information and data gaps.

Innovation projects are looking at new tools and technologies that can be deployed to support longer term visibility of, and interactivity with, the LV network.

[70] ED2 LV Monitoring Engineering Justification Paper (EJP) provides further details.

We have a Connectivity Model under development which is building up the electrical connectivity of our network across all voltage levels, including LV.

In parallel we are building up a customer model which will be overlaid such that we will have a picture of where and how customers are connected along different LV feeders. Our ED1 IT Project 'Connectivity+' is supporting the development of this capability and will continue to be augmented with our enhanced ED2 IT project, 'Connectivity++'.

Using the information above we will provide anticipative information and investment in network reinforcement and flexible services as appropriate to minimise delays and barriers LCT uptake.

The LV Strategy gives context and impetus to these challenges and opportunities, and sets-out actions that we will take going forward to continue to address these challenges and build upon the work that is already being done.

# 4. OUR STRATEGIC APPROACH

To develop an LV Strategy and ensure it is can be effectively implemented in the business, we need a sound understanding of the following:

- the **outcome** we are seeking to achieve;
- **what** key actions we must take;
- **why** we must take these actions; and
- **how** we intend to enable and deliver these actions.

## 4.1. THE OUTCOME

There are three LV Strategic Outcomes for the LV network. Referring to Figure 28.
In Green we have a customer-focused outcome; centred on enabling a smart, transparent network with which customers are able to easily and usefully interact, and which is responsive to their needs.

- In Blue, our asset-related outcome is focused on the LV network itself and the assets; the outcome is to provide a safe and reliable network which we can achieve through enhanced monitoring, flexible operation, and a better understanding of our assets.
- In Orange, our load-related outcome is focused on the provision of an efficient network; one which can connect capacity and accommodate LCT uptake.

These specific LV Strategic Outcomes align with the overall Strategic Outcomes for the SSEN Distribution Business which form the basis of our ED2 Business Plan, as shown in Figure 28.

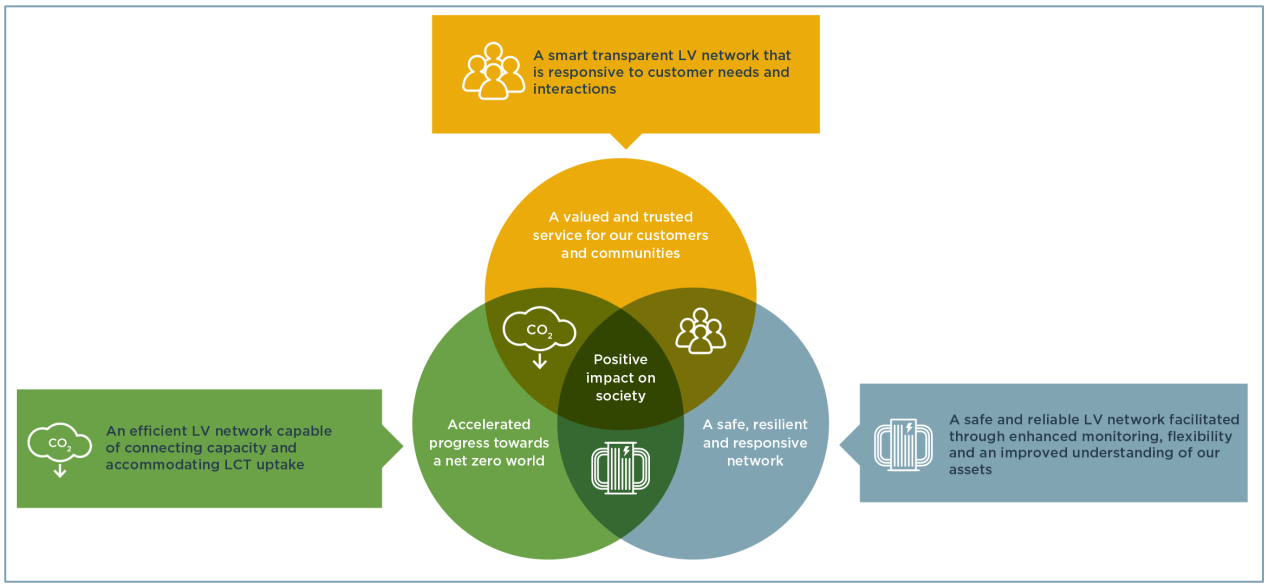


Figure 32 – Interpretation of our Strategic Outcomes for our LV Network

The following sections outline the What, Why and How for each of the LV Strategic Outcomes. We have ensured actions are aligned across the three areas such that efficiencies can be made, and the delivery of the LV Strategy will support and synergise with other key business strategies and the ED2 business plan.

# 4.2. IMPROVED UNDERSTANDING OF OUR LV ASSETS

A safe and reliable LV network facilitated through enhanced monitoring, flexibility and improved understanding of our assets


| WHAT must we do to improve understanding of our LV assets? | WHY is this action required? | HOW can we achieve this? | Reference for delivery ED2 Business Plan |
|---|---|---|---|
| **Understand the health of our assets** | To ensure we invest when necessary, align with load related drivers, and ultimately balance network cost against customer cost and broader societal cost | ▪ Digitalise our asset management systems as per our Digital Strategy to enable faster, more coordinated data access and overall data reliability. | C4 -Safe Resilient Responsive Network / Insights & Automation + OT |
| | | ▪ Ensure our maintenance and inspection plans follow asset management policy on inspection criteria. | CV30 – Inspections<br>CV31 – Repair & Maintenance |
| | | ▪ Ensure information is fed back into asset management systems and records are kept up to date. | CV17 – Rising Laterals & Mains |
| **Understand and address legacy issues with faults – reduce the level of faults on the LV network.** | To avoid customer disruption, improve network reliability, improve fault restoration performance, and improve customer and stakeholder trust | ▪ Continue to deploy LV monitoring and fault management devices (e.g., Bidoyng) in areas with high incidence of faults. Pro-actively manage legacy issues in known problem areas as well as analysis of fault patterns. | CV11 - LV monitoring |
| | | ▪ Deploy LV monitoring devices on all new substations as standard from ED2. | |
| | | ▪ Develop tools to analyse data from monitoring devices and feed this into Outage Management System (OMS) and maintenance plans. | Non-Load Strategy Annex: CV30 – Inspections; CV31 - Repairs and Maintenance; CV11 – Progress to net zero / Platform; C4 – Positive impact on Society / Insights & Automation |
| | | ▪ Map information on problematic assets to load and non-load investment plans to support cost-benefit analysis (CBA) and to ensure that we are investing efficiently. | CV7a – Asset Replacement |
| **Understand the impact of providing flexibility services on the health of our LV assets** | To enable us to use flexibility services to resolve capacity issues while ensuring it doesn't adversely impact the health of existing assets | ▪ Test and stimulate the flexibility services market at LV level | CV4 – Progress to net zero / Insights & Automation<br>C4 – Progress to net zero / Flexibility Markets (Platform) |
| **Understand and address asset failures due to specific characteristics**<br><br>**(e.g. LV Consac cable) or circumstances (e.g. excessive tree growth)** | To enable us to form and implement effective strategies to address these items (e.g. replacement programme for Consac cable, tree cutting strategy), ensuring we align with other ongoing work (such as I&M activity) and making efficiencies where possible | ▪ Utilise LV Monitoring and other operational technologies to improve fault finding and digitise reporting processes. | C7 – STEPM (Non-op)<br>C4 – Positive impact on Society – Insights & Automation<br>C4 - Safe Resilient Responsive Network / Platform |
| | | ▪ Ensure fault and remedial action records are logged centrally in our asset management systems. | Non-Load Strategy Annex<br>CV26 - Faults |
| | | ▪ Perform root-cause analysis (where practicable) or data analytics on faults to better understand the extent of issues on our network and implement efficient solutions. | C4 – Positive impact on Society (Insights & Automation); C4 - Safe Resilient Responsive Network / Platform |
| **Ensure we align with our Losses Strategy when making asset investment decisions** | The Losses Strategy has been developed to optimise losses and suggests minimum requirements for assets to meet this objective | ▪ Ensure Losses Strategy is followed when undertaking LV asset replacement work. | C4 – Positive impact on Society – Insights & Automation<br>C4 - Safe Resilient Responsive Network / Platform. The direct losses costs sit in table CV21 and our approach is outlined in our Environmental Action Plan A 15 |

Table 31 – Actions for improving understanding

Table 31 provides details of the actions we will take to develop an improved understanding of our LV assets and LV network.

Understanding the health of our existing LV assets, taking action to diagnose asset failures and address legacy issues will improve our overall LV network reliability through better coordination of remedial and investment actions. Aligning with the Losses Strategy ensures any actions and investments we do make will adhere to losses related policy to improve network performance and help deliver on our Business Carbon Footprint and our sustainability goals. This approach will stand us in good stead to manage future challenges as they arise. A key feature of the ED2 business plan is the implementation and roll out of LV flexibility services, as part of our transition to DSO, and so it is vital that we test and stimulate this marketplace to understand the impact that flexible operation could have on the health of our LV assets.

To enable us to achieve this, we must ensure our processes and systems for collecting and recording data and information is digitalised in line with our Digital Strategy. It should be centrally stored, easily accessible and kept up to date. In doing so, we will support and enhance several other business functions and activities, including:

- Facilitate LV monitoring roll out by providing information to help optimise device location installation.
- Support network analysis with improved data, tools, and models to support future maintenance plans and outage planning.
- Enable root cause analysis to be performed on faults and solutions to be implemented more effectively.
- Feed into investment planning, supporting efficient investment through improved understanding and knowledge of asset health.
- Map the amount of flexibility active on each network to model and predict half hourly price market-based demand peaks and understand Flexibility Service contracting potential; and
- Understand tariff distribution.

# 4.3. AN EFFICIENT LV NETWORK TO SUPPORT LCT UPTAKE

An efficient LV Network capable of connecting capacity and accommodating LCT uptake


| WHAT actions will allow us to ensure adequate capacity is available? | WHY is this action required? | HOW can we achieve this? | Reference for delivery ED2 Business Plan |
|---|---|---|---|
| **Understand the network and where our customers are connected** | To enable us to more accurately forecast demands and future LCT uptake on a more granular level, and consequently ensure we are investing appropriately to manage this and proactively providing capacity. | ▪ Continue to build the network Connectivity Model in Electric Office, including the LV network. | |
| | | ▪ Roll-out monitoring on LV assets loaded to 80% or more to better understand capacity constraints and patterns of growing demand. Also roll out monitoring in areas of generally poor LV network visibility. | CV11 |
| | | ▪ Use Smart Meter data to obtain an improved and more accurate view of customer connectivity and demand profile and refine load forecasts and identify locations which will benefit from LV monitors | C4 – Positive impact on Society / Insights & Automation |
| | | ▪ Use Smart Meter data to understand the 'Flexibility index' of each LV network and its resulting response to price signals. | C4 – Progress to net zero / Flexibility Markets (Platform) |
| **Understand the operational state of the network and the running arrangements** | To verify the true state of the network under normal operating conditions and ensure we are making investment decisions taking full consideration of abnormal running arrangements (e.g. back-feed via link-box) | ▪ Capitalise on planned maintenance and inspection activity by gathering more detailed information on the operational state of the network where this isn't the primary activity (e.g. link box configuration) | |
| | | ▪ Ensure information is routinely reported back to the Connectivity Model, and the Control room. | |
| | | ▪ Ensure any network reconfiguration actions are reported and logged centrally. | |
| **Address looped services that may impact our ability to provide customers with capacity** | To ensure we remove any barriers to customer LCT uptake | ▪ Respond promptly to customer requirements for larger fuses to allow them to connect LCTs in a timely manner. | Load Strategy Annex |
| | | ▪ Physical inspections to proactively address known issues with capacity limitation on domestic services (e.g. looped services) | Load Strategy Annex |

| | | | |
|---|---|---|---|
| | | ▪ Undertake the work required to upgrade domestic service capacity from 60A to 100 A where and when needed. And to implement the appropriate supporting commercial policy to ensure we do not deter or hinder LCT uptake for any individual customers. | Connections Strategy Annex |
| **Seek to understand how the behaviour of our customers is changing, and what factors are contributing to these changes** | To allow us to map what we know about where customers are connected to the LV network, and how we expect their behaviour to change, ultimately providing better forecasts. | ▪ Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc.<br>▪ Work in a Whole Systems way with local authorities, including gathering information from their strategic plans. | Whole Systems Annex / work force planning |
| | | ▪ Continue to collaborate with the ENA and other UK DNOs on industry-wide knowledge and information sharing on customer behaviour and network requirements e.g., the ENA Embedded Capacity Register. | C4 – Trusted and Valued service / Customers & Ecosystem |

Table 32 – Actions to ensure LCT uptake for net zero

Table 32 provides details of the actions we will take to ensure that our LV network is able to meet the net zero challenge by supporting the significant uptake in customer LCT.

For us to offer network capacity to our customers to enable them to connect LCTs (such as EVs, solar PV and/or heat pumps), we must first understand where we do and don't have spare capacity on the existing network. A critical aspect of this strategy is the plan to collect more information on, and therefore gain a better understanding of, our LV network and customer connectivity, including:

- Where our LV customers are connected.
- How the LV network is configured; and
- Where constraints are likely to appear in future on the LV network.

On the customer side, our understanding of our customers can be improved by working in a Whole Systems way with our stakeholders, including collecting and analysing additional data and information – such as applications for EV charger grants or engaging with Local Authorities on their plans. We can also build a fuller and more accurate picture of customer behaviour by implementing sophisticated data analytics tools. By drawing on, and analysing, limited information from multiple sources – and combining this with broader information on area demographics and other socio-economic factors, we can greatly improve our planning and decision-making to ensure we meet customer needs, when and where it is required.

On the network side, a combination of addressing legacy issues (i.e., looped services), deploying LV flexibility services and building a clear picture of our network connectivity and operational state through the Network Connectivity model (and eventually the Digital Twin in an LV control room) will position us to be able to respond to customer needs efficiently and undertake investment cost-effectively.

# 4.4. A SMART AND INTERACTIVE LV NETWORK

A smart transparent LV network that is responsive to customer needs and interactions


Table 33 – Actions for a smart and interactive LV network

| WHAT must we do to deliver a smart, transparent network? | WHY is this action required? | HOW can we achieve this? | Reference for delivery ED2 Business Plan |
|---|---|---|---|
| **Develop the capability to operate and manage the LV network in real-time** | The LV network will change drastically in the coming years and will require a more proactive approach to operation and control | • Create digital twin of LV network based on the Connectivity Model to use in LV control room/control system. | C4 – Progress to net zero<br>C11 – Progress to net zero |
| | | • Roll-out monitoring and communications infrastructure to collect real-time data from across the LV network. | Digital Investment Plan<br>CV11 |
| | | • Expand and improve on LV automation to develop a more responsive network overall. | C4 - Digitalisation Strategy |
| | | • Leverage the use and value of LV Monitoring, and other Operational Technology (OT) data by developing data analytics tools to process and understand data that is collected. | C4 - Digitalisation Strategy |
| **Undertake actions necessary to enable DSO functionality at LV, taking guidance from our DSO Strategy** | The transition to DSO will allow us to accommodate significant electrification of heat and transport – using our existing asset base efficiently and in a way that enables us to serve our customers flexibly | • Roll out monitoring and communications infrastructure in line with our DSO Strategy to collect real-time data and enable DSO functions e.g. flexibility. | C4 – Progress to net zero / Flexibility Markets (Platform) |
| | | • Use learnings from other DSOs on how LV Flexibility services can be procured and offered. | DSO Annex 11.1, Appendix F – 'Delivering Value Through Flexibility' |
| | | • Proactively recruit flexibility services across all potentially at-risk networks both directly in the case of large customers and through intermediaries such as suppliers and aggregators. | |
| | | • Build up understanding of customer readiness for flexibility services and LCT connection status | |
| | | • Co-ordinate our LV flexibility services management with higher voltage requirements and those of the ESO. | |
| **Align with our Digitalisation Strategy when considering roll out of OT and IT** | Operational Technology (OT) and Information Technology (IT) are critical to improving visibility of our network and enabling more real-time control functionality through data exchange. Our Digitalisation Strategy [1] outlines the ways in which we are working to enable this. | • Roll out monitoring and communications infrastructure in line with our Digitalisation Strategy to enable the collection real-time data and enable control functionality. | Digital Investment Plan<br>CV11 |

Table 33 provides details of the actions we will take to ensure a smart and interactive LV network that is responsive to customer needs and interactions.

It is crucial that we provide a smart and transparent network that customers can interact with, and that is responsive to their needs. This will be best enabled by digitalisation and our transition to DSO. Linking into our Strategic Outcomes to provide a safe and reliable network with capacity to connect LCTs, this outcome will see us provide the infrastructure and systems to empower our customers with more choice and freedom to participate in energy markets and maximise the value they gain from connecting LCTs.

Our development of a network Digital Twin and an LV control room will improve network responsiveness and allow for increasing real-time controllability as LCT uptake increases, flexibility services become more pronounced and a full transition to DSO at LV can be realised.

## 4.5. A POSITIVE IMPACT ON SOCIETY

Bringing together the key actions set out to deliver on our LV Strategic Outcomes, we will provide a smart, reliable, accommodating and customer-friendly network. We will work towards having a clear picture of the existing network and its future requirements to ensure we optimise investment in our LV network while minimising the frequency of interventions. Achieving this will yield enormous efficiencies in time and cost in the long run, while also ensuring we minimise customer disruptions as well as our impact on the environment.


We are also aware that a positive impact on society includes full and fair consideration of customers in vulnerable situations. Accelerated progress towards a net zero world must be part of a just transition – ensuring we accommodate the needs of existing and well as new consumers.

The actions set out in this strategy present a real opportunity to improve coordination of our investment plans and ensure our network does not become a barrier to customers who choose to adopt LCTs. This will be supported by an improved understanding of our network and our assets, through a combination of proactive monitoring and data analytics. Mapping to information collected about evolving customer behaviour and other external influences will ultimately allow us to take a much clearer, more holistic view of the likely network and customer needs in different areas. It will also help us to identify the optimal time and scale of investment to ensure we invest efficiently, effectively reducing costs and customer disruption, while providing adequate capacity and network reliability as it is needed. Working with wider stakeholders, such as gas, water and telecoms industries to streamline investment plans will also avoid duplication of customer disruption and bring about cost efficiencies across the different sectors.

By optimising delivery of our three LV Strategic Outcomes – our asset-based outcome to ensure a safe and reliable network; our load-based outcome to deliver an efficient network to connect capacity; and our customer-focused outcome to provide a smart, interactive network – we can also ensure we create a positive impact on society.

# 5.BUSINESS-WIDE BENEFITS

It is very important to identify areas of synergy and cross-over where efficiencies can be made or benefits from an action can be maximised. An example of this relates to improving data, information and understanding of the network. Every business area working on, and with, the LV network will benefit from additional and enhanced data and information going forward. We believe that it is critical to every area of our electricity distribution business.

| BUSINESS AREA | KEY BUSINESS OBJECTIVES | DATA REQUIREMENTS |
|---|---|---|
| OPERATIONS | Timely repair of faults | • Network connectivity<br>• Fault location<br>• Feeder location and fault history<br>• Number of customers connected |
| SAFETY | Safe project execution | • Network connectivity<br>• Fault location<br>• Feeder location and fault history<br>• Number of customers connected |
| CONNECTIONS | Efficient design of connections | • Local network connectivity, including looped services<br>• Local network loading / available capacity<br>• Local Network Plans |
| PERFORMANCE | Customer satisfaction and opportunities for continued improvement | • CI/CML<br>• Fault and maintenance records<br>• Asset information e.g. age, condition<br>• Losses Strategy |
| ASSET MANAGEMENT | Effective management of asset classes and preventative actions | • Health Index<br>• Maintenance records<br>• CI/CML<br>• Asset Strategy |
| ED2 | Robust planning and investment decision making | • Demand (max, cyclic) of feeders and transformers<br>• Ratings of feeders and transformers<br>• Network connectivity<br>• Asset condition and performance<br>• Uptake and connection of LCTs, including location<br>• Local Network Plans<br>• Connected generation/DER assets |
| DSO | Enable market participation in flexibility and other services | • Demand (max, cyclic) of feeders and transformers<br>• Thermal and voltage issues<br>• Customer capability to participate in flexibility market<br>• DSO Strategy<br>• Connected generation/DER assets |
| FUTURE NETWORKS | Develop scenarios and tools for future planning across all business areas | • Network connectivity<br>• Uptake and connection of LCTs, including location<br>• Flexibility service options<br>• Digital Strategy<br>• Connected generation/DER assets |

Figure 33 - key business objectives and the data that is important for each business area

Figure 33 highlights the key business objectives and the data that is important for each business area.

Several of the actions proposed to deliver on our LV Strategic Outcomes will ensure data is collected, cleansed and readily available to the different business areas. This will in turn provide widespread improvements in meeting our business objectives, and ultimately in delivering our LV Strategic Outcomes.

Improvements in understanding of network connectivity, and having access to more and better data, will bring the following benefits to the different business areas:

i. Operational staff need to know exactly what work they are undertaking and on what asset, where the asset(s) is located and what it is connected to. They must also have the right tools available to ensure efficient working practice and minimal delays. Greater understanding of the network will enable a more robust project planning process overall and improve fault finding activities.

ii. A more robust planning process will result in fewer incidents and a better health and safety record for SSEN.

iii. Our Connections activity will benefit from increased visibility of the local network, its capacity to accommodate additional generation and/or demand and any other plans for the area such that they can design an efficient connection. In future it will be helpful to know where EV chargers are being connected (it would also be useful to see how well this match with the EV Strategy and the DFES analysis on an ongoing basis).

iv. Improvements in procedures across operations, safety and connections will result in improved performance. Better fault and maintenance records could form part of this and feed into the operations and safety business areas. Further improvements in operations and performance through better planning and procedures can also be achieved by logging information centrally and making it available for future projects.

v. Asset management of LV assets will be better coordinated with improved visibility of asset age, condition, maintenance records and performance data. Assets are currently managed in our asset management system, fed by inspection data from our operational staff. It is critical that data in the asset management system is consistent with that being used in other business areas.

vi. The ED2 business plan is being prepared using data and data analytics tools currently available within the business. More granular information about the LV network will allow us to make more informed and justifiable investments across their LV asset portfolio.

vii. The DSO transition cannot be achieved without data availability and the capability to use and exchange this data. This will largely be facilitated by the Digital Strategy and the DSO Strategy, but the importance of DSO on the LV network is expected to be significant and so this must be enabled through the provision of data and communication systems.

viii. Data and an understanding of network connectivity are critical to the work being done by our innovation team. Recognising that it will take significant time and effort to achieve complete coverage and visibility of the LV network, it is important that we maximise the value of the information we do have. By developing robust data analytics tools, we will improve our understanding of the network and use this information to support efficient decision making.

Collectively, the key datasets required by the business areas can be summarised as follows.

- Network connectivity
- Fault location
- Feeder location
- Number of customers connected
- Connected generation assets
- Fault and maintenance records
- Network loading/capacity
- Maximum demand
- Asset health information
- Asset ratings information
- Customer behaviour

Mapping the required datasets listed above to the actions proposed to meet our LV Strategic Outcomes shows that almost universal business-wide benefits (in this case specifically relating to improving network visibility and data availability) can be achieved through focused effort in the delivery of a few of these actions. This is shown in Table 34.

Table 34 – Mapping the data sets

| DATASET | CORRESPONDING ACTIONS | HOW WE WILL DELIVER ON THESE ACTIONS |
|---|---|---|
| NETWORK CONNECTIVITY | • Understand the network and where our customers are connected<br>• Understand the operational state of the network and the running arrangements | • Continue to build the network Connectivity Model in Electric Office, including the LV network. |
| | | • Roll-out monitoring on LV assets loaded to 80% or more to better understand capacity constraints and patterns of growing demand. Also roll out monitoring in areas of generally poor LV network visibility. |
| | | • Use Smart Meter data to obtain an improved and more accurate view of customer connectivity, and eventually demand profiles. |
| FEEDER LOCATION | | • Capitalise on planned maintenance and inspection activity by gathering more detailed information on the operational state of the network – e.g. link box configuration – where this isn't the primary activity. |
| NUMBER OF CUSTOMERS CONNECTED | | • Ensure any network reconfiguration actions are reported and logged centrally. |
| | | • Build up understanding of customer readiness for flexibility services and LCT connection status. |
| FAULT & MAINTENANCE RECORDS | • Understand the health of our assets<br>• Understand and address legacy issues with faults<br>• Understand and address asset failures due to specific characteristics or circumstances | • Ensure our maintenance and inspection is following asset management policies which should outline inspection criteria for health information. |
| | | • Continue to deploy LV monitoring and fault management devices (e.g., Bidoyng's) on the LV network in areas with high incidence of faults and to manage legacy issues; do this pro-actively in known problem areas as well as re-actively as faults occur and fault patterns arise.<br>• Deploy LV monitoring devices on all new substations as standard from ED2. |
| | | • Develop tools to analyse data from monitoring devices and feed this into Outage Management System (OMS) and maintenance plans. |
| ASSET HEALTH INFORMATION | | • Improve fault finding and reporting processes<br>• Data based health and pre-fault detection. |
| FAULT LOCATION | | • Perform root-cause analysis (where practicable) or data analytics on faults to better understand the extent of issues on our network, and implement efficient solutions. |
| ASSET INFORMATION | • Seek to understand how the behaviour of our consumers is changing, and what factors are contributing to these changes<br>• Understand the operational state of the network and the running arrangements<br>• Develop the capability to operate and manage the LV network in real-time | • Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc. |
| | | • Work in a Whole Systems way with local authorities, including gathering information from their strategic plans. |
| | | • Roll out monitoring and communications infrastructure to collect real-time data and enable DSO functions e.g. flexibility. |
| | | • Maximising the use and value of LV monitoring (and other OT) data by developing tools to process data that is collected. |

## 5.1. ENERGY DATA TASKFORCE

June 2020 Ofgem published an Open Letter: 'Review and next steps: RIIO digitalisation strategies'. The letter provides feedback on the RIIO Digitalisation Strategies which have been developed by industry. In this letter, Ofgem continues to strongly support the recommendations of the Energy Data Taskforce and confirms that it intends to introduce a licence condition requiring network companies to comply with 'Data Best Practice' guidance.

One of the headline recommendations of the Energy Data Taskforce is the principle of Presumed Open which is now one of the 12 core principles. Presumed Open actively encourages open data and data sharing which will enable decarbonisation, stimulate innovation, and help support the growing number of UK based digital energy innovators.

# 6. ENABLING THE STRATEGY

The previous sections have set out the key actions we must undertake to deliver on the Strategic Outcomes set for the LV network. This section focuses on how we can best enable the required actions.

## 6.1. Asset Health Management

Better understanding the health (condition) of our LV network assets is one of the key actions we must seek to deliver to meet our Strategic Outcomes. The impact of the changing operational philosophy i.e., bi-directional power flows and different cyclic demand patterns, on asset health must be considered.

The LV network is complex and a substantial length of time and a significant effort to gather accurate health information on all our assets will be required. Using other tools at our disposal, such as data analytics, will provide a good degree of confidence in what we know about the assets, which we can use to make decisions, as we work towards building up our database.

There are already systems in place where asset health information is logged. The focus therefore should be on:

- Improving the accuracy and range of the asset health information (age, condition, etc) in our databases as well as working towards correcting any errors such that the information can be relied upon across the business. **This would provide reliable data for multiple business functions, including load and non-load related investment planning.**
- Implementing robust maintenance and inspection procedures that extend beyond the current remit could be an efficient means of collecting more and better data on asset condition. **This will support improvement of asset health databases and maximise value of maintenance and inspection activities.**
- Digitalising, standardising central logging and reporting of all information is critical to ensure our databases are always up to date. **This will ensure the whole business always has access to the latest asset information.**
- Training and upskilling maintenance and inspection teams to empower them to undertake a range of activities, such as installing LV monitors. **This could deliver efficiencies across operational activities.**
- Develop tools to process and analyse data. **This information could inform future maintenance and inspection plans, feed into the OMS or support investment decision making.**

### 6.1.1. ASSET MANAGEMENT POLICIES

We have a Strategic Asset Management Plan (SAMP) specifically for our distribution networks which sets out a risk framework. The SAMP and the LV Strategy actions must align on issues relating to asset health and asset management.

We also have some specific strategies relating to LV assets, such as link boxes and service cut-outs. Our proposed LV Strategy actions seek to complement these strategies, particularly as these will help us deliver on our strategic objectives.

When assets are being replaced, this will be done in accordance with the Losses Strategy. This includes minimum sizing for LV cables (i.e. large section e.g. 300mm$^2$) and minimum ratings for transformers. Other loss reduction opportunities should also be considered on a case-by-case basis e.g. phase balancing.

### 6.1.2. FAULTS

Improving how we detect, locate and remedy faults, including legacy fault issues, on our LV network will have a significant impact on the performance of our network, the service we provide to our customers and the investment decisions we make.

Presently we face several challenges in relation to fault detection, including:

- Our LV network is not extensively monitored and so often we must wait for a customer to advise that they are off supply to be made aware of a fault. We have commenced the application of smart meter alerts to manage network outages. This process will increase with the increased penetration of Smart Meters on our network.
- The network connectivity information supplied to our operational teams can be inaccurate and so time must be spent locating the right circuit, asset, or customers to isolate.
- The nature of the fault is not always known, and so operational teams may not be equipped with the appropriate tools to undertake the necessary remedial actions.
- Remedial actions taken on a fault are not always recorded centrally so fault history on circuits is not always complete.
- Root cause analysis is not conducted due to missing or incomplete fault histories and repeat issues are not escalated as a result.

We have known legacy issues on our LV network, and these must be addressed as a priority as per our Strategic Asset Management Plan. This can be enabled by implementing a consistent approach to our fault-finding activities.

- More extensive deployment of our fault management operational technologies and LV monitoring should be rolled out on the LV network: proactively in known problem areas; reactively as faults occur; and more generally in areas of poor visibility. **This will speed up fault detection times, and ultimately restoration times. This could also help to better understand the operational health of assets which will support us in avoiding/preventing failures.**
- Maintenance and inspection activities should be coordinated with a focus on addressing priority issues in accordance with monetised risk. We should also seek to optimise the scope and scale of interventions where possible to ensure efficiencies (i.e., across load, non-load and fault response activities). **This will reduce recurring issues and minimise customer disruption.**
- Clear instructions on what interventions/solutions to deploy in specific circumstances should be provided. **This will allow operational teams to equip themselves with the right tools and minimise delays in restoration times.**
- A standard, digitalised reporting procedure should be rolled out where pro-forma information is collected and reported centrally following the completion of any fault-finding activity. **This will improve data collection which will feed into wider databases for asset management etc.**

- Fault histories, built up through successful implementation of the previous actions, should be made available to operational teams. **This will support the operational teams in their reporting.**

- An escalation procedure (root cause analysis, investment etc) should be put in place to effectively detect and action recurring issues. **This will ensure issues are dealt with efficiently and in order of priority.**

These enabling actions will bring about long-term benefits by incrementally building up our knowledge and data on our assets and faults, so there needs to be options available such that we can manage faults in the short to medium term.

The 'Fault Discovery' proof of concept is trialling the use of prediction analytics and machine learning to "*highlight areas of the network or individual components that may be subject to failure in the short/medium term to help build future investment plans*". This programme uses data analytics to support in the build-up of these records by identifying susceptible or problematic areas, or assets, thus allowing focussed effort in particular areas to address legacy and other issues.

Pre-Fault Analysis is a proof of concept explored through Network Investment Allowance (NIA) funding, in ED1, by SSEN's Future Networks Team. SYNAPS 2 NIA is set to complete in 2022. At LV level the aim of the program is to capture data from source and integrate within SSEN's existing IT systems. This will facilitate seamless management generating efficiencies through reduction of occurrences of Customer Interruptions and Customer Minutes lost. The data will also be housed in the companies Azure platform allowing for SSEN's Data Strategy to deliver its programme of data quality management enabling our data to drive efficiencies and support best practice when operating our Network as a whole.

## 6.2. NETWORK CONNECTIVITY

Understanding how our LV network is connected is of critical importance as we move further through the energy transition.

If we are to provide capacity to our customers on an ongoing basis, we must always know where capacity is available and where the network is constrained.

It is therefore crucial that we not only improve our understanding of where our customers are connected and how the network is configured, but we also ensure this information is accessible and of sufficient accuracy.

### 6.2.1. CONNECTIVITY MODEL

Our Connectivity Model is an ongoing initiative which requires extensive collection of additional data and information on the Extra-High Voltage (EHV), HV and LV distribution networks.

The model is being built manually, and so far, the focus has been on the HV network . Full HV connectivity is due to complete in 2021[71].

[71] Approximately 40% complete as at June 2021.

The LV network presents unique challenges in this respect, particularly as we do not currently have full oversight of the LV network. It will take time and resources to build up this visibility. We can enable and accelerate this process by:

- Committing resources to continue to collect information and build up the Connectivity Model at LV. **This should accelerate progress and demonstrate the importance of this initiative.**
- Capitalise on maintenance and inspection activity to gather detailed information on the operational state of the LV network i.e. the status of link boxes etc, and/or install monitoring equipment (where this is not the primary activity already). **This will maximise value of maintenance and inspection activities and bring overall efficiencies in data collection.**
- Ensure any operational activity carried out on the LV network that involves network reconfiguration is reported and logged centrally. **This will ensure the latest network connectivity information is always readily available.**
- Support delivery of Connectivity++ IT Investment. The primary focus of this project is to link customer information to our connectivity model.

### 6.2.2. MONITORING AND DATA

Pivotal to the development and success of the Connectivity Model, and eventually the LV network digital twin, is the availability of data and the provision of visibility through this data. Data is required to build up our picture of the network, and to maintain visibility on an ongoing basis. Over time, historical records and profiles could also be used to look at patterns of activity and behaviour to detect and diagnose issues.

Fundamentally, we will improve our visibility of the LV network through:

- Roll out of monitoring devices strategically, focusing in areas of generally poor visibility, areas that are known to be constrained and areas where we expect high uptake of LCTs. **This will offer a level of coverage across all areas of network, with more extensive coverage of areas where we anticipate high levels of activity or specific issues to arise . We are expecting to install over 19,000 LV monitors in ED2, and thanks to recent funding as part of the Green Recovery this will be supported by around 1,700 monitors being installed in ED1, bolstering the circa 700 already procured. By end of ED2 this will equate to 20% of our LV network being monitored, supplemented by advanced analytics for 100% visibility.**
- Develop data analytic tools that allow us to process data into useful information that can be actioned as appropriate. **This will allow us to leverage the data we collect for decision making, and also infer information about areas with limited coverage using sophisticated data analytics** (see Section 6.5).

### 6.2.3. CONNECTED CUSTOMERS

Customer connectivity is another key factor in building our Connectivity Model. SSEN has information on its customers, mostly a combination of Geographic Information System (GIS) data and Meter Point Administration Numbers (MPAN). Combining this with smart meter data will drastically improve the granularity of visibility we have on where our customers are connected. It is therefore imperative that SSEN:

- Supports the continued roll out of smart meters to reach 95% coverage by 2024 in line with government targets. **This will ensure we meet government targets and can rapidly benefit from increased visibility at customer level which is something that has never been available previously.**
- Work with industry, including BEIS, Ofgem and other network companies, and consumers to break stigma of smart meters and privacy concerns. **This will ensure we are actively engaged with customers and industry to advocate a mutually beneficial position regarding data privacy.**
- Provide necessary infrastructure (liaising with the telecoms industry where required) to capitalise on the collection of data. **This will enable data to be collected and fully utilised for the benefit of SSEN and its customers** (see Section 6.3.6).

The roll-out of smart meters presents a huge opportunity for us as the devices can be configured to collect data in numerous ways. We must specify what data is required to meet our different business objectives e.g. half hourly data should be collected to inform on LV circuit capacity, daily profile data could be used to assess customer behaviour, annual data could be used to get a more accurate view of maximum demand. With these activities comes the question of value to customers versus the cost of providing the necessary infrastructure and data processing capability and storage capacity.

## 6.3. DSO AND DIGITALISATION

The transition to DSO and the Digitalisation Strategy are complementary. The DSO function cannot be fully implemented without an appropriate digital infrastructure.

### 6.3.1. DSO

The intention is to overlay the Connectivity Model with a customer model which is currently being populated using GIS data, although smart meter data will be leveraged when there is more extensive coverage. Eventually, the Connectivity Model will allow us to develop a digital twin of the whole network from LV to 132kV and this model will be accessible in the ADMS/control room. From here, real-time data from LV monitors, smart meters and other OT can be used to show the real time status of the LV network which will become an increasingly important function to support our DSO activities. This is being supported by the ADMS+ IT project in ED2.

### 6.3.2. LV FLEXIBILTY

With the uptake of LCTs and the electrification of demand, comes the opportunity for greater levels of customer involvement in the day-to-day safe and efficient operation of our LV network.

Flexibility services are expected to play a huge role in the future operation of our LV network. Flexibility services can take many forms depending on what network issue is being resolved by the service e.g. thermal overload, voltage, fault level. At LV, it is expected that the most prolific flexibility service will be related to thermal overloads and the needs to manage power flows and consumption at specific times. These services could include smart EV charging or time-of use tariffs, and would involve participation from customers, suppliers and possibly aggregators.

Using flexibility on the LV network provides a cost-effective approach to managing customer demand, as compared to asset replacement.

The Load Managed Area (LMA) in SHEPD where c. 87,000 customers have controllable heating load is a good example of how flexibility can be used to defer network reinforcement through the management of consumption. Since the 1980s, SSEN has been able to schedule heating demand to diversify peak load during the night. The radio tele switching used to control the LMA is being decommissioned by the BBC and so SSEN is implementing alternative arrangements to ensure the same level of peak load diversification can be achieved. A longer-term strategy to lift LMA switching restrictions – where the (customer) benefits of so doing, outweigh the (customer) costs – is being progressed alongside short-term measures to maintain safe and reliable operation of the network.

'LV flexibility where customers opt-in is still a relatively novel concept and there are likely still several challenges and issues to work through. SSEN is exploring this through innovation LV Flexibility. In collaboration with National Grid Electricity System Operator (ESO), our 4D Heat project has explored whether controlled electrified residential heating in Scotland can reduce the curtailment of renewable generation, without adversely impacting the LV distribution network. Also, SSEN with Octopus Energy, Ohme and the ESO have teamed up to conduct the UK's largest ever home energy flexibility study. CrowdFlex, will analyse 25,000 household energy use patterns to demonstrate how households might change their behaviour and charge electric vehicles, heat pumps and home batteries at different times to access cheaper, greener power. The analysis looks at how those usage patterns change in response to price signals from Octopus Energy's smart tariffs. The findings are expected to will show how changes in energy price and demand affect consumers and what impact that has on a flexible smart grid powered increasingly by renewables.'The findings will also be shared collaboratively across industry, academia and with policy makers and regulators, with SSEN helping inform and influence the energy system of the future across GB.

### 6.3.3. TRANSITION

The ENA Open Networks Project (Open Networks) is focussed on defining the DNO transition to a DSO model and has been endorsed by the UK Government's Smart Systems and Flexibility Plan. Open Networks is a key platform for Whole Systems collaboration and communication across DNOs to enable the DSO transition.

Based on the intermediate outputs of Open Networks, TRANSITION will design, develop, demonstrate, and assess the common tools, data and system architecture required to implement the proposed models produced by the Workstream 3 project. This will include:

- Developing roles and responsibilities for market participants, and market rules to allow market participants to transact services.
- Clarifying the requirements and implement a Neutral Market Facilitator (NMF) platform for trials; and
- Engaging and consult with stakeholders.

Oxfordshire has been selected for the trials due to its replicability and high customer appetite for a smart grid architecture. Project LEO (see Section 6.3.4) is building on the outcomes and deliverables from the TRANSITION project to trial DSO models and the flexibility service marketplace and Whole Systems working.

### 6.3.4. LEO

Project LEO is an industry-first and has set out to explore how the growth in local renewables, electric vehicles (EVs), battery storage, vehicle-to-grid (V2G) technology and demand side response can be supported by a local, flexible, and responsive electricity grid. Thus, ensuring value for consumers and opportunities for communities and market providers.

Project Leo will be one of the most wide-ranging and holistic smart grid trials ever conducted in the UK.

The project aims to replicate, and trial aspects of the Distribution System Operator (DSO) models being explored by industry, government, and the energy regulator via the Energy Networks Associations Open Networks Project. It will balance local demand with local supply in a real-world environment, helping to test markets, inform investment models and, ultimately, assess the benefits of flexibility to the energy system.

Project LEO is already delivering useful insights on DSO and Whole Systems working that have directly informed our ED2 plans and strategies in these areas.

### 6.3.5. ENABLING DSO FUNCTIONALITY

The transition to DSO is ongoing, and the requirements will evolve as SSEN and wider industry learns more from innovation projects such as those described above. We believe that the following key enabling actions should be undertaken to facilitate the transition:

- Create digital twin of LV network to use in LV control room/control system. **This will provide real-time visibility of the network and facilitate network-wide system operation activity.**
- Capitalise on the roll out of monitoring and communications infrastructure to collect real-time data and enable DSO functions. LV monitors and other OT is being rolled out to address issues in other business areas, but the data can support wider business interests such as DSO, where data and visibility is critical. These devices can be configured to collect different datasets depending on requirements. **This will maximise the value of OT by using it to support the DSO transition as well as other business functions.**
- Develop tools to process data that is collected such that it can be used for DSO functionality and in the DSO services marketplace. **This will ensure flexibility and other services are procured in an efficient manner, by using accurate network data and processing it appropriately.**

- Use learnings from other DSOs on how LV DSO services can be procured and offered. **This will accelerate progress and enable us to offer a wider variety of options to our customers.**

### 6.3.6. DIGITAL INFRASTRUCTURE

In our Digital Strategy we have a clear vision of the digital world and what it will mean for SSEN. This vision includes access to open data, a flexible and intelligent network, a thriving DSO marketplace and an energy ecosystem with our customers and other industry participants.

The LV network must embrace this vision and take guidance from the Digital Strategy when considering the roll out of IT, OT, and communications infrastructure. Our digital infrastructure will require investment much like our electrical infrastructure and will align with LCT uptake and other decarbonisation actions.

The key actions in the Digital Strategy are:

- Continue to build the digital foundations – building critical capabilities to meet basic needs and exceed expectations. **Roll out of more extensive monitoring on the LV network will play a key role in supporting delivery of this action.**
- Building an Open Data future in the wider digital ecosystem – work with customers and industry to trial data sharing to enable Whole Systems collaboration. **Customer engagement will be undertaken to better understanding customer behaviour and how it may evolve**.
- Enable the future whole energy system and competition – enable a competitive marketplace underpinned by Open Data. **This will be critical to enabling flexibility at LV.**
- Continued use of the Common Network Model (CNM) as this allows the various data sets to be linked up in an interoperable way.

## 6.4. WHOLE SYSTEMS AND STAKEHOLDER ENGAGEMENT

As a customer focused DNO, we already actively undertake stakeholder engagement. As we undertake to improve our LV network, our customers will become a key feature of our LV network operation in future. They will be empowered to interact with the network and have a real impact on how it operates as they evolve into active participants rather than passive consumers. We must enable our customers to interact with our network.

In addition, as the UK transitions to net zero, boundaries are being blurred and interdependencies created between different sectors such as electricity, gas and transport. This transition is necessitating a coordinated, Whole Systems approach to manage the energy system effectively at an efficient cost for consumers.

Working in a Whole Systems way requires local communities and authorities to collaborate with organisations in the energy, transport, telecoms, water and other sectors. For example, the decarbonisation of heat, with a range of alternative solutions (hydrogen, electric heat pumps and district heating) requires cross sector collaboration and Whole Systems thinking to optimise costs and investment while meeting environmental commitments. Similarly, the uptake of EVs requires electricity companies to collaborate with local authorities, original equipment manufacturers (OEMs) and transportation agencies

(including Highways England and Transport Scotland) to ensure sufficient charging infrastructure is available across the country.

Our Whole Systems strategy provides the framework and approach for SSEN to work with our stakeholders to deliver net zero ambitions. This includes engaging with stakeholders such as local authorities, the transport sector and other DNOs to share information and better understand our customers' needs to deliver our LV strategy[72].

### 6.4.1. CUSTOMER BEHAVIOUR

There are different parameters that we can use to measure how we think customers might behave in future, such as where they live and their socio-economic status, and these parameters play a role in how the DFES are developed.

Much like we are doing to build up our knowledge and understanding of the network and our assets, we will build our understanding of customer behaviour. This will be done in several ways, including:

- Build up picture of customer activity through collaboration with EV retailers, EV charge point installers, heat pump installers, flexibility aggregators etc. **This will provide visibility of where new technology is being connected and can feed into network analysis on asset health and demand profiles.**

- In line with our Whole Systems strategy, actively engage with local authorities and work together to develop and implement strategic plans. **This will provide wider visibility and foresight of local/regional plans that could require investment from SSEN.**

- Leverage smart meter data. **This will, over time, allow us to spot changes in behaviour patterns through changes in demand profile.**

Further to understanding the behaviour of our customers in relation to what technologies they might connect and when, will be an appreciation of how they will use these technologies. There will likely be a sliding scale of participation, from entirely passive to optimally active i.e., some customers will not change their behaviour just because they have an electric car, while others will seek to ensure they are on a tariff to reduce costs and they will modify their behaviour to suit this, they may also participate in flexibility services. The way we roll-out flexibility at LV, and how successful it will be as a network operation and management tool, will depend largely on how our customers intend to (or are incentivised to) behave and participate. It will also depend on how "ready" the local LV networks are to support flexibility services. This will require pilots and trials adopting Whole Systems working in close cooperation with suppliers, customers, and other third-party participants, such as aggregators.

## 6.5. INNOVATION AND DATA ANALYTICS

We are actively engaged in innovation and we continue to deliver projects (such as those described in section 6.3) which have data analytics aspects. Data analytics has been widely recognised, not just by SSEN but by wider industry, as having a key role in our ability to reach net zero. With the strategic importance of the LV network becoming more apparent, and the overall lack of visibility and understanding of the network we have now, using data and developing analytics will be paramount.

[72] More detail on our Whole Systems strategy can be found in our ED2 Business Plan, Ch.12, Annex 12.1.

There will always be a degree of uncertainty with the LV network. Even if we have access to a large volume of data, there will always be missing information or knowledge that we don't have. We therefore need a change of mindset and philosophy – one which embraces the lack of knowledge, and makes decisions which more actively manage risks e.g. the risk of coincident EV charging etc. These risks exist on our current LV network, but the way that these networks have been designed (conservatively) has meant we haven't needed to consider this way of working before. Exchanging asset risk for commercial risk will become a key aspect of the LV network in future.

To support this change in philosophy, we need data and the ability to use it to quantify risks. Just having data is not enough to remove risk, we must also be able to use it to inform our decision making. The analysis used to inform the ED2 business plan (see ED2 load-related investment business plan annex for more details) is a good example of how we are using data analytics to inform our decision making on a large scale. More data will give us more information to work with (LV monitoring and smart meters) and this refines and improves the information we get out of the analysis.

## 6.6. DELIVERY

Taking into consideration the challenges, risks and actions required by SSEN outlined in the previous sections, we must seek to optimise these to enable us to deliver on the LV Strategic Outcomes in the most efficient way. Two key considerations we will address when approaching the development and progress of the LV network are the skills base and the supply chain.

### 6.6.1. SKILLS AND TRAINING

We must consider our workforce and whether we have the appropriate skills to support the actions set out in this strategy. Specifically.

- A need to **upskill our operational teams such that they can be more flexibly deployed and bring overall efficiencies to the business** and our customers.
- Recognition of the potential emergence of skills gap, specifically at LV, where **we will need power systems expertise as well as data analytics knowledge**.

The two skillsets will complement one another, and teams will need to communicate more effectively to ensure we are able to translate data into information and ultimately decisions.

### 6.6.2. SUPPLY CHAIN

We must work with our supply chain to ensure we are able to deliver what we set out to deliver as per this strategy. The energy transition is not unique to SSEN and similar activities are likely going on within the other UK DNOs. There are potentially huge volumes of monitoring equipment, circuits, transformers and other equipment going to be needed in the coming years and so **we must look to mitigate potential bottlenecks in the supply chain as much as possible by developing a robust procurement strategy.**

# Appendix E KEY TRENDS IN DFES SCENARIOS

Here we summarize some of the most important trends central to our analysis for the ED2 period. The full DFES documents for 2020 in the North and South should be consulted for a detailed analysis of technology evolution across our licence areas.

## Key 'North' trends

- **Onshore wind:**
  - The area has a strong presence of large-scale and small-scale onshore wind deployed over the last 20 years;
  - A large pipeline of viable projects, many with planning permission, drives strong capacity growth in the near term as new routes to market for onshore wind appear and new projects become increasingly commercially viable and deployment certainty increases;
  - The area has an excellent amount of developable wind resource, resulting in increased connected capacity out to 2050 in all scenarios;
  - A significant amount of new capacity is also driven by repowering of existing sites with more efficient and higher capacity turbines
- **Hydropower:**
  - The area represents a large proportion of the UK's current and potential future distributed hydropower capacity;
  - The majority of the 807 MW currently connected consists of large-scale projects, built up to 70 years ago, with no further development of this equivalent scale seen in almost 20 years;
  - The future potential for additional capacity is likely to be single-MW or smaller scale projects, as most opportunities for large-scale hydro generation have largely been exploited. The level any additional capacity is uncertain and dependent on whether small-scale renewable generation is supported. The recent Feed-in Tariff has given a good indication of how subsidy has allowed some new hydropower generation to be commissioned, despite being a mature technology;
  - Therefore, scenario projections for distribution network hydropower capacity in the area are highest in Consumer Transformation and Leading the Way, where small-scale renewables play a vital role in achieving net zero. Under System Transformation and Steady Progression, hydropower development in limited in the area
- **Electricity storage:**
  - A significant amount of distribution network connected battery storage capacity (MW) is seen in all scenarios by 2050, compared to the very small 1.2 MW today;
  - This reflects a significant near-term pipeline of 668 MW, including several projects that are in the c.20-50 MW range;
  - The highest connected is in the Leading the Way scenario, with c.1.2 GW modelled to connect to the distribution network by 2050. This is ~6% of the FES 2020 total GB projected capacity on the distribution network in this scenario by 2050.

This reflects a moderate proportion of the pipeline going through to connection, additional standalone, generation co-location and high energy user projects connecting in the medium term and a notable overall uptake of domestic batteries by 2050 in this scenario

- The lowest connected capacity is seen in the System Transformation scenario, with 290 MW connected by 2050. This reflects a more general scenario assumption of a lesser need for distribution network connected flexibility, overall lower levels of electrification and renewable electricity generation deployment and a significantly lower uptake of domestic batteries. Also with the transmission network in Scotland being a voltage tier lower than the rest of the UK, some additional battery storage projects that may be connecting at 132kV between 2019 and 2050 are not within the scope of the DFES analysis for the North of Scotland licence area;
- Whilst a significant increase in connected capacity is seen in all scenarios by 2050, beyond the sizeable pipeline there is a degree of uncertainty around the development of battery storage projects under any business model. This uncertainty relates to high levels of competition in national and local flexibility markets and challenging network charging reforms that could adversely impact the commercial viability of distribution network battery storage assets in the longer term. With the strong level of distribution network connected generation seen in the North of Scotland area (especially onshore wind), the proposed introduction of higher network costs in substation areas that are 'generation dominated', could possibly affect the viability of distribution network generation in the area. With battery storage currently being classed as a subset of generation for network charging purposes, this may similarly affect the connection costs for the export capacity element of a battery storage connection offer. However, with the clear network support and flexibility role that storage could provide to the electricity network in the area, Ofgem could consider either a dispensation or adjusting regulation for electricity storage in the future

- **Electric Vehicles**:
  - At present, EVs (including plug-in hybrids) represent approximately 0.7% of all vehicles in the North of Scotland area, which is below the GB average of nearly 1%. This is, however, representative of other predominantly rural regions in GB. More urban centres in the region, such as for Dundee and Stirling city regions, have an EV uptake more typical of GB average
  - However, as a result of Scottish Government's ambition for transport decarbonisation, North of Scotland is projected to align with the GB average uptake rate for EV's by the mid-2020s;
  - Electrification is the key route to decarbonising transport in the scenarios, with hydrogen's role focussed in contributing to the decarbonisation of HGVs and buses in most scenarios. North of Scotland is projected to have a higher uptake of hydrogen vehicles compared to the national scenarios

- **Electric vehicle chargers**:
  - At present, the installation of public EV chargers is significantly above the GB average per EV vehicle in the North of Scotland area. The density of chargers is less if compared to the geographical size of the region. This reflects the support received and 'Chargeplace Scotland's' active participation in the Scottish EV charger market. This trend is expected to continue in the near-term, until demand for charging increases;

- Hot spots for public charger deployment include some of the urban areas as well as some of the islands and tourist areas.
- There is significant uncertainty regarding the shape and size of the future charger network; in particular the split between off-street home charging versus public charging, as well as the market share between ultra-fast charging hubs versus lower voltage on-street, neighbourhood and municipal charging. The DFES projections therefore aim to represent the envelope of the possible spread and rate of deployment of EV chargers. In many modelling areas there is a lack of behavioural evidence and so interim assumptions have been made;

- **Heat pumps and direct electric heating**:
  - In line with decarbonisation strategies across the country, the North of Scotland area sees a dramatic shift to low carbon heating in all three of the scenarios that meet net zero targets;
  - Engagement with Scottish Government around heat decarbonisation ambition (including some of measures and targets highlighted in the recently published Climate Change Plan) has been reflected in all scenarios, particularly under Consumer Transformation and Leading the Way. This results in the North of Scotland area seeing rapid heat pump roll-out in the near and medium term, reflecting high levels of ambition to decarbonise off-gas and on-gas homes in Scotland. This has a correlative effect of limiting the uptake of hybrid heat pumps, which are not a focus of Scottish Government's heat decarbonisation strategy;
  - In the more electrified Consumer Transformation and Leading the Way scenarios, ~77% of homes are heated by a non-hybrid or hybrid heat pump by 2045, as Scotland's net zero target year. Whilst not directly connecting or impacting the electricity distribution network, it should be noted that the remaining 23% of homes in the area will also be heated by alternative low carbon heating technologies, such as hydrogen boilers or district heat networks;
  - The North of Scotland is a unique area, with many factors directly impacting low carbon heating options. 44% of homes in the area are not connected to the mains gas network, three times the GB proportion of 15%. This results in heat pumps playing a strong role in heat decarbonisation across the licence area, even in scenarios where hydrogen is available for heating on-gas homes;
  - Furthermore, the particularly rural and remote areas of the Highlands and Islands in the north and west of the area experience high prices for oil, LPG and solid heating fuels. This has already resulted in high levels of electrified heat in these areas;
  - Uptake of commercial heat pumps see a similar trajectory to domestic heat pumps. However, the penetration of heat pumps is lower than in domestic homes, due to the higher proportion of commercial units expected to use direct electric heating throughout the scenario timeframe. Currently, according to non-domestic EPC records, almost 50% of GB commercial properties are heated by electric heating, compared to 8% of domestic households;
  - Under the Consumer Transformation and Leading the Way scenarios, just over 60% of commercial properties are heated by a form of heat pump in 2050. Leading the Way has a significantly higher number of hybrid heat pumps;
  - Direct electric heating is compliant with net zero emissions targets and is therefore not explicitly targeted for heat decarbonisation measures. However, as one of the most expensive heating methods and being less fuel-conversion efficient than heat pumps,

scenarios with high levels of support for low carbon heating solutions will see a reduction in existing homes with direct electric heating over time. Scottish Government, through the Scottish Fuel Poverty Act (2019) seeks to eradicate fuel poverty as far as is reasonably possible by 2040, therefore solutions such as direct electric heating is one of the solutions considered when aiming to tackle carbon emissions and fuel poverty;

  - Conversely, direct electric heating is currently installed in some new build homes, and this will elicit an increase in direct electric heating deployment in homes in some scenarios, particularly in the near-term. • In the long-term, all three net zero scenarios see a reduction in direct electric heated homes from today's levels, due to the prevalence of affordable electric heat pumps, hydrogen heating or low carbon district heat networks for the majority of homes in these scenarios. District heat networks, whilst not likely to be primarily fuelled by electricity, is a low carbon heating solution that is another key feature of Scottish Government's heat decarbonisation strategy. Therefore, whilst not a specific output or projection under the DFES 2020 scenarios, there could be a notable role for low carbon district heat networks supplying some clusters of homes in more urbanised areas of North Scotland in the longer term, especially under the System Transformation scenario

- **Small scale solar PV:**
  - Domestic-scale solar PV has historically seen high levels of uptake in the North of Scotland licence area, despite the lower levels of irradiance compared to the rest of the country. This deployment was driven by particularly high rates in the early years of the Feed-in Tariff;
  - While domestic-scale solar PV is a more attractive investment in sunnier regions, levels of irradiance are less influential on uptake compared to utility-scale ground-mounted solar PV. As a result, the capacity of domestic-scale solar PV in the licence area is expected to broadly align with national trends in each of the four scenarios, driven largely by consumer engagement, uptake of other domestic technologies (such as electric vehicles and domestic batteries), and a future reduction in the costs of domestic solar array installations. In the highly ambitious Consumer Transformation scenario, around one in six domestic properties host rooftop PV by 2050;
  - Small-scale commercial-scale solar PV is typically impacted by a blend of the drivers of domestic-scale and utility-scale solar PV. Consequently, commercial-scale solar PV deployment has a similar trajectory to these technologies, with strong capacity growth under the Consumer Transformation scenario in particular

### Key 'South' trends

- **Large scale solar PV**:
  - Due to the high levels of irradiance relative to the rest of the UK, the Southern England area has some of the highest levels of largescale solar PV deployment in the country;
  - This level of development interest is expected to continue throughout the timeframe of the scenarios out to 2050, due to the attractive levels of solar irradiance, though not to the same extent as in the baseline years. This is due to solar PV costs continuing to fall, resulting in ground mounted solar PV projects being built out across all of GB rather than only in the south of the country;
  - With solar PV panel efficiencies also increasing continuously, there is the potential for the repowering of baseline sites to drive a large increase in overall solar PV capacity as projects reach the end of their operational life

- **Gas fired generation**:
  - The connected capacity of decentralised natural gas fired generation in the Southern England area is above average when compared to some other parts of the UK
  - Currently connected is ~550 MW reflective of a strong gas network coverage in the area, as well as notable industrial regions such as Swindon, Portsmouth, and West London;
  - As well as three sizeable OCGT sites, there are several gas CHPs and reciprocating engine projects of varying capacities connected across the area. There is also a significant pipeline of ~419 MW of potential new natural gas generation sites in the area, which is a mixture of all three natural gas sub-technologies;
  - The DFES analysis for gas generation in the Southern area has therefore focused on three distinct areas:
    1. Modelling the potential future pathways for each of the natural gas sub-technology sites in the baseline. This modelling specifically looks at the potential for many of these baseline sites to decommission across the 2030s and 2040s, in line with the Leading the Way, Consumer Transformation and System Transformation scenarios meeting net zero emissions by 2050;
    2. Assessing the development potential for the significant pipeline, as new/additional fossil fuel generators, within the scenarios and the equivalent future decommissioning of these sites, likely to mostly be within the 2040s;
    3. The longer term DFES analysis also considers the potential for some of the known baseline/pipeline projects that may operate more commercially, to convert their generator assets to be able to run on hydrogen instead of natural gas. This has been determined to mostly likely be in city or local authority regions within the area that have been identified as hydrogen supply zones
  - For the three scenarios that are compliant with the target to achieve net zero emissions by 2050 in England, all-natural gas generation is decommissioned before 2045 and a small amount of hydrogen fuelled generation capacity is modelled to come online between 2035 and 2050. In the Steady Progression scenario, the total connected capacity of natural gas generation is higher in the area in 2050 than in 2019, though this connected capacity peaks across the 2030s and sees a small decline across the 2040s. At a high level, the long-term role of natural gas and hydrogen fuelled generation is uncertain. Gas generation is an inherently flexible and responsive technology, that can potentially support the operability of the electricity system in the near-term. However, with natural gas being a carbon intensive fuel and with exhaust emission abatement technologies potentially being prohibitively costly to fit to smaller scale generators, the running of unabated natural gas generation in the long-term is at odds with net zero emission targets. Add to this the significant level of uncertainty around the likely strategy for hydrogen production, hydrogen supply infrastructure and the locational or national scale of hydrogen demand, the potential scale of hydrogen fuelled generation is equally uncertain. This uncertainty is reflected through a notable spread of capacity trajectories across the scenarios
- **Electricity storage**:
  - In the Southern area, a significant amount of distribution network connected battery storage capacity (MW) is seen in all scenarios by 2050, compared to a relatively small 3.2 MW today;

- This reflects a significant near-term known pipeline of 736 MW, including two projects that are greater than 100 MW and several others that are in the c.30-50 MW range;
- The highest connected capacity is in the Leading the Way scenario, with ~2 GW modelled to connect to the distribution network by 2050. This is ~12% of the FES 2020 total GB projected capacity on the distribution network in this scenario by 2050. This reflects a significant proportion of the pipeline going through to connection, as well as additional standalone, co-location and high energy user projects connecting in the medium term and a notable uptake of domestic batteries by 2050 in this scenario;
- The lowest connected capacity is seen in the System Transformation scenario, with ~0.4 GW connected by 2050. This reflects a more general scenario assumption of a lesser need for distribution network connected flexibility and overall lower levels of electrification and renewable electricity generation deployment. It also reflects a significantly lower uptake of domestic batteries;
- Whilst a notable increase in connected capacity is seen in all scenarios by 2050, beyond the sizeable pipeline there is a degree of uncertainty around the development of battery storage projects under any business model. This uncertainty relates to high levels of competition in national and local flexibility markets and network charging reforms that could impact the long-term business case of distribution network storage assets. The degree of uncertainty impacting deployment under each storage business model has been reflected through the four scenarios

- **Electric vehicles**:
  - At present, EVs represent approximately 1.1% of all vehicles in the Southern area, which is above the GB average of nearly 1%. The EV uptake rate in the Southern area is expected to remain ahead of the GB average until the late 2020s in most scenarios, when EV uptake becomes increasingly ubiquitous;
  - Electrification is the key route to decarbonising transport in the scenarios, with hydrogen contributing to the decarbonisation of HGVs and buses
- **Electric vehicle chargers**:
  - At present, the installation of public EV chargers in the Southern area is approximately the same as the GB average. This trend is expected to continue as EVs become increasingly ubiquitous in the medium term;
  - Compared to the previous 'SSEN High granularity projections for low carbon technology[73]' report, the uptake rate of EV chargers is higher and the envelope of charger capacity in 2050 has narrowed. This is predominantly due to an increased uptake of EVs in the less ambitious scenarios in the scenario compared to the 2019 report, thus narrowing the EV uptake projections;
- **Heat pumps and direct electric heating**:
  - In line with decarbonisation strategies across the country, the Southern area sees a dramatic shift to low carbon heating in all three of the net zero compliant scenarios;
  - In the more electrified Consumer Transformation and Leading the Way scenarios, there is a significant increase in heat pump deployment during the next decade. This is consistent with the UK government's target to deploy 600,000 heat pumps per year by 2028 as well

[73] High granularity projections for low carbon technology uptake, June 2020: https://www.regen.co.uk/wp-content/uploads/Regen-SSEN-High-granularityLCT-projections-Final.pdf

as the legal commitment to meet the 4th and 5th carbon budgets. By 2050 ~70% of homes are heated by a non-hybrid or hybrid heat pump;

- The housing stock in the area is broadly like the average GB home when considering energy efficiency, size, building form and tenure. However, 23% of houses in the area are not connected to the gas network, significantly above the national average of 15%. This results in heat pump uptake exceeding the national trajectory, particularly in the near and medium term where off-gas homes are more likely to convert to a heat pump. The lower number of on-gas homes also reduces the uptake of hybrid heat pumps;
- Uptake of commercial heat pumps experiences a similar trajectory to domestic heat pumps. However, the penetration of heat pumps is lower than in domestic homes, due to the higher proportion of commercial units expected to use direct electric heating throughout the scenario timeframe. Currently, according to non-domestic EPC records, almost 50% of GB commercial properties are heated by electric heating, compared to 8% of domestic households;
- Under the Consumer Transformation and Leading the Way scenarios, just over 60% of commercial properties are heated by a form of heat pump in 2050. Leading the Way has a significantly higher proportion of hybrid heat pumps. • Direct electric heating is compliant with net zero emissions targets and is therefore not explicitly targeted for heat decarbonisation measures. However, as one of the most expensive heating methods, scenarios with high levels of support for low carbon heating solutions such as heat pumps will see a reduction in existing homes with direct electric heating over time;
- Conversely, direct electric heating is currently installed in some new build homes, and this will elicit an increase in directly heating homes in some scenarios, particularly in the near-term
- In the long-term, all three net zero scenarios see a reduction in direct electric heated homes from today's levels, due to the prevalence of affordable electric heat pumps, hydrogen heating or low carbon district heat networks for the majority of homes in these scenarios

- **Small scale solar**:
  - Domestic-scale solar PV in the Southern England licence area has historically seen levels of uptake area in line with the national average, despite having higher levels of irradiance compared to the rest of the country. This deployment was driven by Feed-in Tariff support in the 2010s
  - While domestic-scale solar PV is a more attractive investment in sunnier regions, levels of irradiance are less influential on uptake compared to utility-scale ground-mounted solar PV. As a result, capacity of domestic-scale solar PV in the licence area is expected to broadly align with national trends in each of the four scenarios. This is driven largely by consumer engagement, uptake of other domestic technologies (such as electric vehicles and domestic batteries), and reduction in the costs of domestic solar array installations;
  - In the highly ambitious Consumer Transformation scenario, around one in six domestic properties hosts rooftop solar PV by 2050;
  - Commercial-scale solar PV is typically impacted by a blend of the drivers of domestic-scale and utility-scale solar PV. Consequently, commercial-scale solar PV deployment sees a similar trajectory to these technologies, with a strong increase in connected capacity under the Consumer Transformation scenario in particular

- **Data centres**:
  - New data centres have the potential to significantly increase electricity demand on the distribution network. They could also potentially become enablers for battery storage, DSR flexibility and sources of heat for heat networks;
  - There are 13 proposed data centre developments with accepted connection offers in the Southern area, totalling 665 MW;
  - Four of these data centres have an accepted import capacity of more than 100 MW;
  - Through discussions with SSEN network planners, many of these sites have proposed staged development, where a proportion of the full accepted import connection is modelled to come online over 3-5 years;
  - This represents a significant amount of new electricity demand on the distribution network in the Southern England licence in the 2020s;
  - Once committed, Data Centre projects tend to have a high acceptance rate and likelihood of being commissioned. The projections have therefore been applied across all four scenarios;
  - Beyond these known projects, no additional capacity has been projected, due to the lack of future development data, FES 2020 scenario projections and publicly available information
- **Domestic air conditioning**:
  - Our estimates of existing domestic AC units has been based on an assumption that nationally, ~1% of homes on average across GB currently have AC units
  - These AC units are likely to mostly be in flats and apartment buildings. With some areas of the Southern England area having notable population density (including more multi-occupancy buildings) and a hotter climate in Southern England, the national figure of 1% has been applied to the area to determine the baseline. This equates to a little over 25,000 AC units in 2019;
  - Based on the National Grid FES 2020 residential energy consumption datasets, domestic AC unit capacity (kW) and assumptions around operating hours, the DFES analysis has projected a significant range of results for AC deployment across the scenarios by 2050:
    - The highest number is seen in Steady Progression, with just under 1.5 million units (~44% of all homes in the area);
    - The lowest number is seen in Leading the Way, with just under 30,000 units (~1% of all homes in the area)

# Appendix F SUMMARY OF LOAD-RELATED EXPENDITURE PROJECTS

| Licence area | IDP submitted | Reference no. | LRE Bucket | Scheme name | CAPEX (£m) | Delivery year | SP | ST | CT | LW | Reporting table |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SEPD | Yes | 44/SEPD/LRE/SCO | Baseline | Fleet and Bramley 400/132kV Substation Group | 54.2 | 2027/28 | | x | x | x | CV1 |
| SEPD | No | 45/SEPD/LRE/YEOVIL | Baseline | Yeovil 132/33 kV Bulk Supply Point Substation | 1.8 | 2025/26 | | x | x | x | CV1 |
| SEPD | Yes | 47/SEPD/LRE/BEAC | Baseline | Beaconsfield 22/6.6 kV Primary Substation | 5.0 | 2025/26 | | x | x | x | CV1 |
| SEPD | Yes | 48/SEPD/LRE/ASHR | Baseline | Ashling Road 33/11 kV Primary Substation | 6.0 | 2026/27 | | x | x | x | CV1 |
| SEPD | Yes | 50/SEPD/LRE/HARL | Baseline | Harvard Lane 22/11 kV Primary Substation | 3.7 | 2025/26 | x | x | x | x | CV1 |
| SEPD | Yes | 51/SEPD/LRE/STOK | Baseline | Stokenchurch 33/11 kV Primary Substation | 3.1 | 2025/26 | x | x | x | x | CV1 |
| SEPD | Yes | 53/SEPD/LRE/EGHA | Baseline | Egham 33/11 kV Primary Transformers and 33 kV Circuit Reinforcements | 3.8 | 2026/27 | x | x | x | x | CV1 |
| SEPD | Yes | 54/SEPD/LRE/ASHP | Baseline | Ashton Park 33 kV Circuits | 2.6 | 2025/26 | x | x | x | x | CV1 |
| SEPD | Yes | 55/SEPD/LRE/MILT | Baseline | 33 kV Circuits of Fulscot 33/11 kV Primary Substations | 2.6 | 2026/27 | x | x | x | x | CV1 |
| SEPD | Yes | 56/SEPD/LRE/NETLEY | Baseline | Netley Common BSP 132/33 kV Substation | 2.8 | 2025/26 | | x | x | x | CV1 |
| SEPD | Yes | 57/SEPD/LRE/AMESBURY | Baseline | Amesbury 132 kV isolator (S) / Salisbury 132 kV circuit breaker bay (P) / 132kV | 1.9 | 2025/26 | x | x | x | x | CV1 |
| SEPD | Yes | 58/SEPD/LRE/ALTON | Baseline | Alton - Fernhurst 132 kV Network Reinforcement | 13.8 | 2023/24 | x | x | x | x | CV1 |
| SEPD | Yes | 59/SEPD/LRE/ BRAMLEY_THATCHAM | Baseline | Bramley - Thatcham - Andover 132 kV Reinforcement | 5.5 | 2023/24 | x | x | x | x | CV1 |
| SEPD | Yes | 60/SEPD/LRE/IVER | Baseline | Iver 132 kV Fault Level Reinforcement | 22.7 | 2025/26 | x | x | x | x | CV3 |
| SEPD | Yes | 61/SEPD/LRE/FAWLEY | Baseline | 132 kV Fawley (P) / SCO Reinforcement Fawley North (S) / 132kV | 1.2 | 2023/24 | x | x | x | x | CV1 |
| SEPD | Yes | 62/SEPD/LRE/MANNINGTON | Baseline | Mannington 132/33 kV substation (P) / Mill Lane 33/11 kV substation (S) / CB Replacement | 0.2 | 2023/24 | x | x | x | x | CV1 |
| SEPD | Yes | 65/SEPD/LRE/EBED | Baseline | East Bedford A 132/22 kV Substation Reinforcement | 4.1 | 2026/27 | x | x | x | x | CV1 |
| SEPD | Yes | 66/SEPD/LRE/Upton | Baseline | Upton EHV System Reinforcement | 10.4 | 2025/26 | x | x | x | x | CV1 |
| SEPD/ SHEPD | Yes | 423/SSEPD/LRE/TRANSMISSION_ CHARGES | Baseline | New Transmission Capacity Charges | 23.2 | 2023/24-2027/28 | N/A - programme of works | | | | CV4 |
| SEPD | Yes | 365/SEPD/LRE/POLE | Baseline | Rutter Pole Replacement Scheme | 10.9 | 2023/24, 2024/25 | N/A - programme of works | | | | CV1 |

| Licence area | IDP submitted | Reference no. | LRE Bucket | Scheme name | CAPEX (£m) | Delivery year | SP | ST | CT | LW | Reporting table |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SEPD | No | 63/SEPD/LRE/DENHAM | Baseline | Denham 132kV circuits | 0.3 | 2024/25 | x | x | x | x | CV1 |
| SEPD | Yes | 107/SEPD/LRE/LOUDWATER | Baseline | Loudwater BSP 132/33kV Transformer and 132kV circuits | 9.0 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 110/SEPD/LRE/YETM | Baseline | Yetminster Primary 33 kV circuits | 0.4 | 2024/25 | x | x | x | x | CV1 |
| SEPD | No | 119/SEPD/LRE/OXFORD | Strategic Investment | Oxford (Osney) GSP 132 kV Circuits | 0.1 | 2025/26 | | | x | x | CV1 |
| SEPD | No | 121/SEPD/LRE/BERI | Baseline | Berinsfield Primary 33kV circuits | 0.9 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 125/SEPD/LRE/STLA | Baseline | Standlake Primary 33/11kV transformers | 1.1 | 2023/24 | x | x | x | x | CV1 |
| SEPD | Yes | 127/SEPD/LRE/CHAR-WOOD | Baseline | Charlbury-Woodstock 33 kV Ring Network Reinforcement | 5.3 | 2023/24 | | x | x | x | CV1 |
| SEPD | No | 130/SEPD/LRE/ALRE | Baseline | Alresford Primary 33/11kV transformers | 1.3 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 132/SEPD/LRE/WARF | Baseline | Warfield Primary 33kV circuits | 0.8 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 133/SEPD/LRE/GORI-CHOL | Baseline | Goring & Cholsey Primary 33kV circuits | 0.4 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 150/SEPD/LRE/BIRD | Baseline | Birdham Primary 33/11kV Transformers | 1.0 | 2024/25 | | x | x | x | CV1 |
| SEPD | No | 156/SEPD/LRE/BEME | Baseline | Bemerton Ring 33kV circuits | 0.4 | 2024/25 | x | x | x | x | CV1 |
| SEPD | No | 159/SEPD/LRE/FEDO_WIMB | Baseline | Wimborne Primary 33/11 kV Transformers | 1.4 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 162/SEPD/LRE/BOUR | Baseline | Bourton Primary 33 kV supply circuits | 0.4 | 2024/25 | x | x | x | x | CV1 |
| SEPD | No | 164/SEPD/LRE/WART | Baseline | Wareham Town Primary 33kV circuits | 0.3 | 2026/27 | x | x | x | x | CV1 |
| SEPD | No | 165/SEPD/LRE/CALN | Baseline | Calne Primary 33kV circuits | 1.2 | 2025/26 | x | x | x | x | CV1 |
| SEPD | No | 167/SEPD/LRE/ALDE | Baseline | Alderton Primary 33/11kV transformers | 0.9 | 2025/26 | | x | x | x | CV1 |
| SEPD | No | 169/SEPD/LRE/BRUT | Baseline | Bruton Primary 33kV Supply Circuits | 0.7 | 2025/26, 2027/28 | | x | x | x | CV1 |
| SEPD | No | 176/SEPD/LRE/FARI | Baseline | Faringdon Primary 33/11kV transformers | 1.1 | 2024/25 | x | x | x | x | CV1 |
| SEPD | No | 183/SEPD/LRE/YATT | Baseline | Yattendon Ring 33kV circuit | 0.3 | 2024/25 | | x | x | x | CV1 |
| SEPD | No | 190/SEPD/LRE/CHIPPENHAM | Baseline | CHIPPENHAM 33kV circuit breaker reinforcement | 0.1 | 2025/26 | | x | x | x | CV3 |
| SEPD | No | 192/SEPD/LRE/LYTCHETT | Baseline | LYTCHETT 33kV circuit breaker reinforcement | 1.0 | 2025/26 | | x | x | x | CV3 |
| SEPD | No | 194/SEPD/LRE/SOUTHAMPTON | Baseline | SOUTHAMPTON 33kV circuit breaker reinforcement | 0.6 | 2025/26 | | x | x | x | CV3 |
| SEPD | No | 195/SEPD/LRE/STRATTON | Baseline | STRATTON 33kV circuit breaker reinforcement | 0.4 | 2023/24 | x | x | x | x | CV3 |

| Licence area | IDP submitted | Reference no. | LRE Bucket | Scheme name | CAPEX (£m) | Delivery year | SP | ST | CT | LW | Reporting table |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SEPD | No | 196/SEPD/LRE/SWINDON | Baseline | SWINDON 33kV fault level reinforcement | 1.0 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 197/SEPD/LRE/SWINDON | Baseline | SWINDON 11kV fault level reinforcement | 0.5 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 198/SEPD/LRE/WOOTTON | Baseline | WOOTTON COMMON 33kV circuit breaker reinforcement | 0.3 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 199/SEPD/LRE/COCKLEBURY | Baseline | COCKLEBURY 11kV circuit breaker reinfocement | 0.1 | 2023/24 | | x | x | x | CV3 |
| SEPD | No | 202/SEPD/LRE/STEEL_SWINDON | Baseline | PRESSED STEEL SWINDON 11kV fault level reinforcement | 0.3 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 204/SEPD/LRE/MILTON | Baseline | MILTON 11kV circuit breaker reinforcement | 0.1 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 210/SEPD/LRE/HILSEA | Baseline | HILSEA 33kV circuit breaker reinforcement | 0.1 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 212/SEPD/LRE/MAYBUSH | Baseline | MAYBUSH 11kV circuit breaker reinforcement | 0.4 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 214/SEPD/LRE/EALING | Baseline | EALING 66kV GSP fault level reinforcement | 1.8 | 2023/24 | x | x | x | x | CV3 |
| SEPD | No | 215/SEPD/LRE/EALING | Baseline | EALING 22kV circuit breaker reinforcement | 1.5 | 2023/24 | x | x | x | x | CV3 |
| SEPD | Yes | 456/SEPD/LRE/LEAMINGTONPARK | Baseline | Leamington Park | 6.8 | 2023/24, 2024/25 | x | x | x | x | CV1 |
| SEPD/SHEPD | Yes | 70/SHEPD/LRE/LVFeeders | Baseline/Strategic Investment | LV feeders - Load related | 19.0 | 2023/24-2027/28 | N/A - programme of works (£7.8m requested in BPDTs) | | | | CV2 |
| SEPD/SHEPD | Yes | 69/SHEPD/LRE/Feeders | Baseline/Strategic Investment | HV feeders - Load related | 33.8 | 2023/24-2027/28 | N/A - programme of works (£12.3m requested in BPDTs) | | | | CV2, CV3 |
| SEPD/SHEPD | Yes | 68/SEPD/LRE/Stransformers | Baseline/Strategic Investment | Secondary distribution transformers - Load related | 33.4 | 2023/24-2027/28 | N/A - programme of works (£14.2m requested in BPDTs) | | | | CV2 |
| SHEPD | No | 71/SHEPD/LRE/SCORRDALE | Baseline | SCORRADALE 33kV Circuits | 0.52 | 2025/26, 2027/28 | x | x | x | x | CV1 |
| SHEPD | Yes | 72/SHEPD/LRE/KEITH | Baseline | KEITH 33kV Circuit Reinfocements | 5.58 | 2027/28 | x | x | x | x | CV1 |
| SHEPD | No | 73/SHEPD/LRE/INVERNESS | Baseline | INVERNESS 33kV Circuits | 0.50 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 74/SHEPD/LRE/TAYNUILT | Baseline | TAYNUILT 33kV Circuits | 0.16 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 75/SHEPD/LRE/ABERNETHY | Baseline | ABERNETHY 33kV Circuits | 1.02 | 2025/26 | x | x | x | x | CV1 |
| SHEPD | Yes | 77/SHEPD/LRE/STMARYS | Baseline | St Marys Primary Substaion P2 Compliance Reinforcements | 3.03 | 2026/27 | x | x | x | x | CV1 |
| SHEPD | Yes | 78/SHEPD/LRE/KILNIVER | Baseline | Kilninver Primary Substation P2 Compliance Reinforcements | 3.44 | 2027/28 | x | x | x | x | CV1 |
| SHEPD | Yes | 79/SHEPD/LRE/SKULAMUS | Baseline | Skulamus Primary Substation P2 Compliance Reinforcements | 2.17 | 2027/28 | x | x | x | x | CV1 |

| Licence area | IDP submitted | Reference no. | LRE Bucket | Scheme name | CAPEX (£m) | Delivery year | SP | ST | CT | LW | Reporting table |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SHEPD | No | 80/SHEPD/LRE/DUNOON | Strategic Investment | DUNOON 33 kV Circuits | 0.69 | 2023/24 | | | x | x | CV1 |
| SHEPD | Yes | 82/SHEPD/LRE/PORTANN | Baseline | PORT ANN 33 kV Circuit Reinforcements | 4.84 | 2024/25, 2025/26 | x | x | x | x | CV1 |
| SHEPD | No | 83/SHEPD/LRE/THURSO | Baseline | THURSO SOUTH 33 kV Circuits | 0.38 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 219/SHEPD/LRE/ASHGROVE | Baseline | ASHGROVE Primary (ED1) | 1.64 | 2023/25 | x | x | x | x | CV1 |
| SHEPD | No | 227/SHEPD/LRE/BRIDGEDON | Baseline | BRIDGE OF DON 33/11kV Transformer | 1.23 | 2024/25 | x | x | x | x | CV1 |
| SHEPD | No | 459/SHEPD/LRE/STORNOWAYREGULATOR | Baseline | STORNOWAY REGULATOR 5L5 (ED1) | 0.50 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 230/SHEPD/LRE/BURGHMUIR | Baseline | BURGHMUIR 33 kV Circuits | 0.01 | 2025/26 | x | x | x | x | CV1 |
| SHEPD | No | 232/SHEPD/LRE/CASHILE | Baseline | CASHLIE 33/11kV Transformer | 0.38 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 460/SHEPD/LRE/BILBOHALLPRIMARY | Baseline | BILBOHALL Primary (ED1) | 1.47 | 2024/25 | x | x | x | x | CV1 |
| SHEPD | No | 244/SHEPD/LRE/CULLODEN | Baseline | CULLODEN 33/11kV Transformer | 0.98 | 2025/26 | | x | x | x | CV1 |
| SHEPD | No | 247/SHEPD/LRE/DRUMRUNIE | Baseline | DRUMRUNIE 33/11kV Transformer | 0.42 | 2024/25 | x | x | x | x | CV1 |
| SHEPD | No | 249/SHEPD/LRE/DUNVEGAN | Baseline | DUNVEGAN 33 kV Circuits | 0.03 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 250/SHEPD/LRE/ELGIN | Baseline | ELGIN 33 kV Circuits | 0.71 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 256/SHEPD/LRE/GISLA | Baseline | GISLA 33/11kV Transformer | 0.38 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 259/SHEPD/LRE/HALKIRK | Baseline | HALKIRK 33/11kV Transformer | 0.41 | 2026/27 | x | x | x | x | CV1 |
| SHEPD | No | 260/SHEPD/LRE/INSCH | Strategic Investment | INSCH 33/11kV Transformer | 0.89 | 2023/24 | | | x | x | CV1 |
| SHEPD | No | 261/SHEPD/LRE/INVERBROOM | Baseline | INVERBROOM 33/11kV Transformer | 0.02 | 2026/27 | x | x | x | x | CV1 |
| SHEPD | No | 269/SHEPD/LRE/LOCHCARNAN | Baseline | LOCH CARNAN 33 kV Circuits | 1.62 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 276/SHEPD/LRE/MINORGRUDIE | Baseline | MINOR GRUDIE 33/11kV Transformer | 0.02 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 281/SHEPD/LRE/NEWPITSLIGO | Baseline | NEW PITSLIGO 33/11kV Transformer | 0.79 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 461/SHEPD/LRE/ABOYNEBALLATER | Baseline | ABOYNE - BALLATER 11kV (ED1) | 1.49 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 286/SHEPD/LRE/QUOICH | Baseline | QUOICH 33/11kV Transformer | 0.40 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 287/SHEPD/LRE/RANNOCH | Baseline | RANNOCH 33 kV Circuits | 1.06 | 2023/24 | x | x | x | x | CV1 |

| Licence area | IDP submitted | Reference no. | LRE Bucket | Scheme name | CAPEX (£m) | Delivery year | SP | ST | CT | LW | Reporting table |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SHEPD | No | 289/SHEPD/LRE/GRUDIEBRIDGE | Baseline | Regulator at Grudie Bridge Regulator | 0.40 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 294/SHEPD/LRE/SHIELDAIG | Baseline | SHIELDAIG 33/11kV Transformer | 0.40 | 2023/24 | | x | x | x | CV1 |
| SHEPD | No | 297/SHEPD/LRE/STRICHEN | Baseline | STRICHEN 33 kV Circuits | 1.43 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 300/SHEPD/LRE/TIRORAN | Baseline | TIRORAN BRIDGE 33/11kV Transformer | 0.02 | 2023/24 | x | x | x | x | CV1 |
| SHEPD | No | 301/SHEPD/LRE/TRESSADY | Baseline | TRESSADY 33/11kV Transformer | 0.37 | 2026/27 | x | x | x | x | CV1 |
| SHEPD | No | 387/SHEPD/REGIONAL/SHETLAND | Baseline | SHETLAND Wider Works | 1.69 | 2024/25 | x | x | x | x | CV1 |
| SHEPD | No | 304/SHEPD/LRE/GRUDIEBRIDGE | Baseline | GRUDIE BRIDGE 11kV Circuit Breakers | 0.11 | 2023/24 | x | x | x | x | CV3 |
| Total | | | | | 349.9 | (£298m in BPDTs) | | | | | |