SSEN DISTRIBUTION NETWORK DEVELOPMENT PLAN

Draft Methodology & Assumptions

March 2024

Scottish & Southern Electricity Networks

CONTENTS

1. INTRODUCTION

The Clean Energy Package comprises European legislation (including EU Directive 2019/944)[1] to drive a unified energy strategy for delivering the Paris agreement. In December 2020, it was transposed into domestic legislation through a number of changes to the Electricity Distribution Licence. This included the introduction of standard licence condition (SLC) 25B. SLC 25B requires Distribution Network Operators (DNOs), including our two licensees Southern Electric Power Distribution plc (SEPD) and Scottish Hydro Electric Power Distribution plc (SHEPD), to publish a Network Development Plan (NDP), setting out their investment plans for the next five-to-ten-year period in relation to 11kV networks and above. It must include:

a) A description of those parts of the DNO's network that are most suited to new connections and distribution of further quantities of electricity;

b) A description of those parts of the DNO's network where reinforcement may be required to connect new capacity and new loads;

c) Information that supports the secure and efficient operation, coordination, development and interoperability of the interconnected system; and

d) Flexibility or Energy Efficiency Services that the DNO reasonably expects to need as an alternative to reinforcement.

To ensure consistency in reporting across all DNOs in terms of SLC 25B, the Energy Networks Association (ENA) prepared a report that sets out the agreed form of sharing data with stakeholders, customers, and consumers. The proposal for the Form of Statement of Network Development Plans was developed as part of Open Networks workstream, which proposed a standardised Standard Network Capacity Report. To meet the requirements of SLC 25B, the NDP is split into three distinct reports, as illustrated in Figure 1 below; the red box highlights the part this document represents:

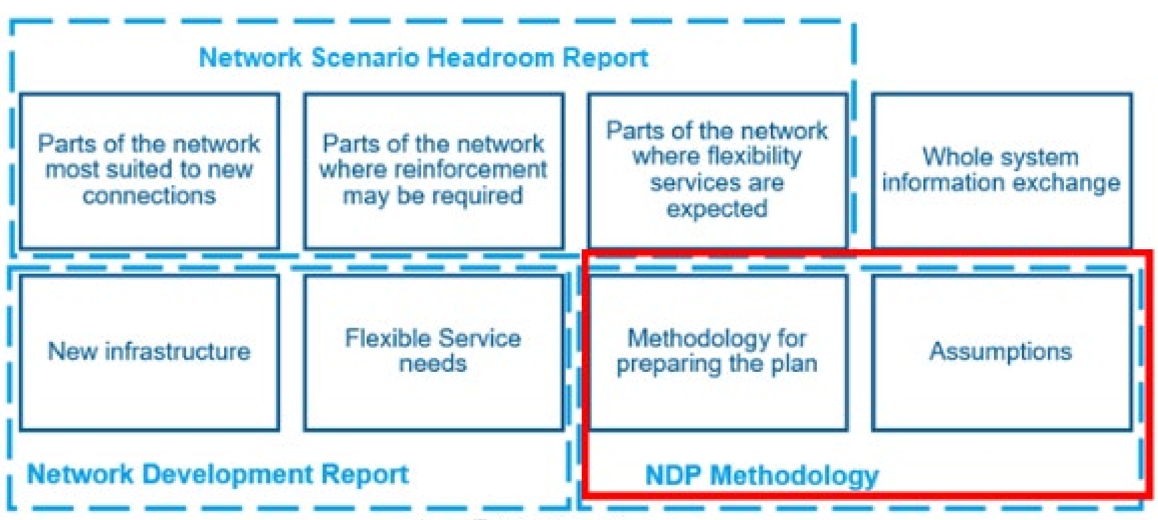

Figure 1 - NDP Reporting Structure

In compliance with SLC 25B, SSEN will update the full Network Development Plan every two years, publishing on the 1st of May. Due to the constantly changing nature of capacity headroom, SSEN will also update the Network Scenario Headroom Report on an annual basis, also publishing on the 1st of May.

In the remainder of this section, we provide an overview of each of the documents comprising the NDP. We also provide further details on our NDP Consultation process and our Open Data Portal, which acts as a single point of access for our network data.

1.1. Network Development Plan (NDP) Methodology & Assumptions

The purpose of the NDP Methodology & Assumptions document is to ensure that the reports, forecasts, and calculations that make up the NDP are clear to the reader. It details the end-to-end network development process starting with forecasting to our best view development plan.

1.2. Network Development Report (NDR)

The NDR provides the reader with valuable additional information on key projects set for delivery in terms of new infrastructure to be installed and upcoming flexible services to be employed. The aim of the information is to provide users with visibility over our network plans and signpost requirements for flexibility services so that users can target developments.

The NDR provides a list of high-level plans for network interventions and flexible service requirements over the next 10 years along with the following information:

Flexibility services	New infrastructure
○ Magnitude; ○ Year of intervention & likely duration; ○ Location of the requirement; ○ Nature of requirement / flexibility product.	○ Timing and high-level scope of intervention; ○ Details of connectivity; ○ Asset quantities & approximate lengths; ○ Equipment ratings; ○ Approximate locations.

Table 1 - Scope of the Network Development Report

1.3. Network Scenario Headroom Report (NSHR)

The main objective of the NSHR element of the NDP is to indicate where it is anticipated that there will be network capacity to accommodate future connections, where further capacity may be necessary and where flexibility services may be required.

The NSHR includes the following components of distribution networks:

- Substations where the greatest voltage is more than 20kV, normally:
- Bulk Supply Points, BSPs (typically 132/33kV or 132/11kV, 66/22kV), and

- Primary substations (typically 66/11kV, 33/11kV or 33/6.6kV, 22/11kV, 22/6.6kV)
- In Scotland, 132/33kV substations are known as Grid Supply Points (GSPs) rather than BSPs, due to the lower transmission/distribution boundary and would therefore be excluded from the network capacity reporting part of the NDP.

Date Range	Today to 2050
Data Granularity	Yearly for the next ten years; five yearly thereafter
Forecast Scenarios	Distribution Future Energy Scenarios (DFES)
Reported headroom/deficit	Demand & Generation
Network Coverage	Distribution voltages down to the secondary primary substation (typically 11kV)

Table 2 - Requirements for NSHR

Further information on the NSHR methodology can be found in section 6 of this document.

1.4. NDP Consultation

In the March prior to our full NDP update, we release our public consultation on our NDP and all associated documents via our website, where we also provide instructions on how to respond. The consultation is open for a period of 28 days and aims to engage stakeholders -- including developers, local authorities, and generators -- on how they use the NDP. The consultation also provides an opportunity for stakeholders to offer feedback on improvements they would like to see.

As part of our consultation period, we also offer the opportunity for one-to-one engagement with our stakeholders.

Our approach aims to increase awareness of the NDP and how it fits in to the information that third parties can access and use to inform investment decisions. We ask stakeholders the following set of questions:

1. To help us understand how to help you, could you outline how you plan to use the information contained in this plan.

2. Does the Network Development Plan provide the information you need to understand our development plans for the network out to 2034? If not, what future improvements could be made?

3. Is the methodology and assumptions used to prepare this plan clear? If not, have you any feedback for future iterations?

4. Is the proposed format for the Network Headroom Report clear? Can you easily identify areas where there is capacity and where there are constraints?

The non-confidential feedback that we receive is published within the Network Development Report for each licence area, along with our acknowledgement and response to this valuable feedback. We will continue to engage with third parties to make them aware of the NDP and continue to seek stakeholder feedback prior to any major revision of the NDP.

1.5. SSEN Open Data Portal

In October 2023, we launched our Open Data Portal[1] to drive forward net zero decisions. Our Data Portal is a single point of access to all the data SSEN publishes and a catalogue of data that brings visibility to our network assets, their location, their usage, and their performance. All documents related to the SHEPD and SEPD NDP submission are published on our Open Data Portal, along with other planning publications such as the Long-Term Development Statement, DFES, Capacity Heatmaps and Embedded Capacity Register (ECR). The timeline of these documents is shown in the figure below. For further information on these publications please see the accompanying Network Development Report.

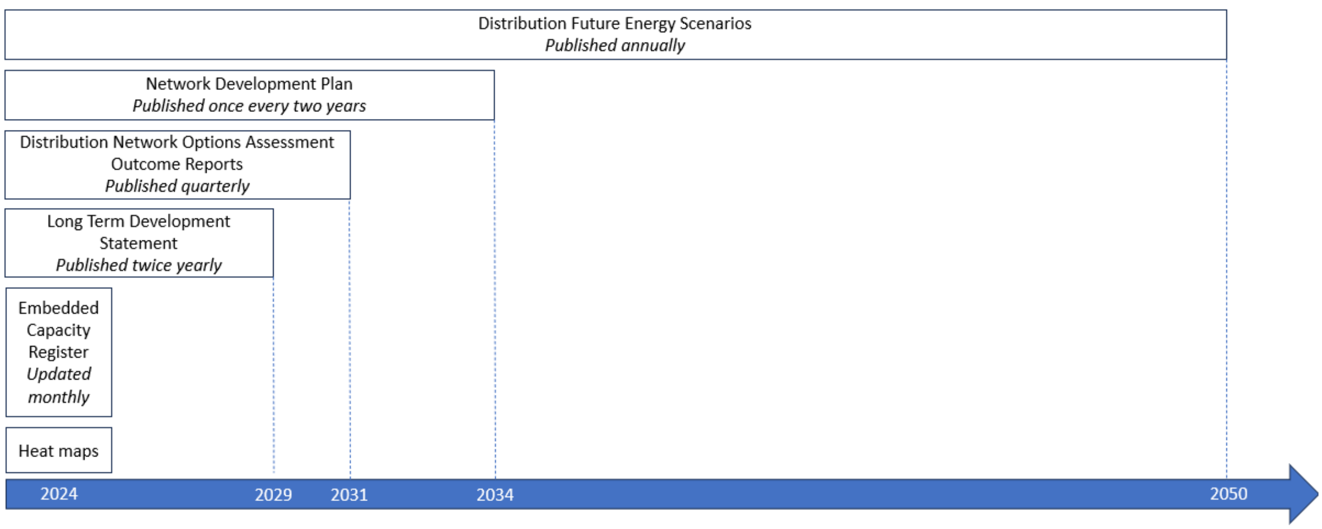

Figure 2 Planning horizons and frequency of publications for NDP and related documents.

1 https://data.ssen.co.uk/

2. THE HIGH-LEVEL STRATEGIC DEVELOPMENT PROCESS

The Network Development Plan contains a range of information developed through our network planning process. As such it is a key requirement of this report to provide further information on our network planning process. SSEN's high level strategic development process is shown below in Fig.3 which performs this function. It is comprised of three main stages which are then explained in further detail through this report;

- **Developing future forecasts** – working with stakeholders to understand their future energy needs and converting these using the Future Energy Scenarios (FES) to produce future Distribution Future Energy Scenarios (DFES) to be used in our strategic development process. This is described further in section 3 of this report.
- **Identifying load-related needs** – using power system analysis to understand the future requirements of our networks. Further context can be found in section 4.
- **The Distribution Networks Options Assessment (DNOA) process** – in this process we develop detailed options involving both flexibility and network solutions to meet future system needs. We then assess these options through industry approved cost benefit analysis. Further detail can be found both in section 5 and our annually published DNOA methodology report[2].
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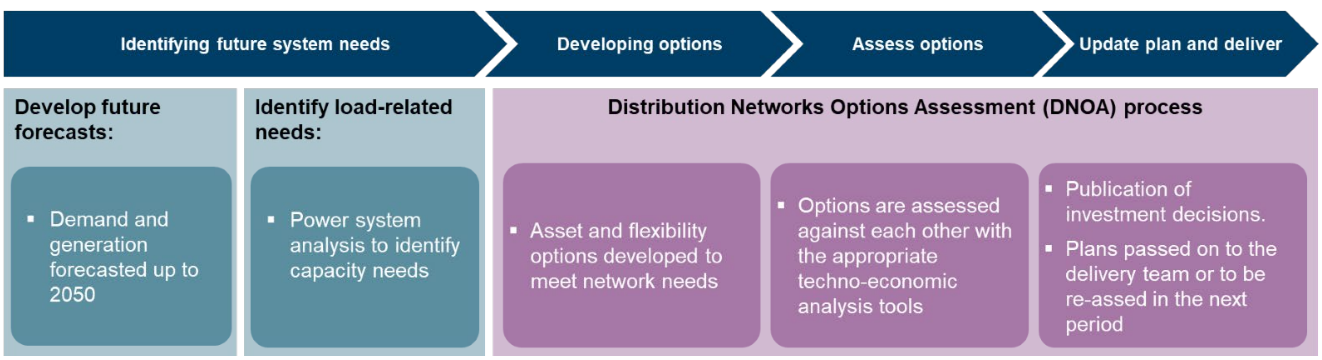

Figure 3 – SSEN strategic development process

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3. DEVELOPING FUTURE FORECASTS

This section describes how we combine regional insights from local stakeholders with the national Future Energy Scenarios (FES) framework to develop a range of future scenarios referred to as the Distribution Future Energy Scenarios (DFES).

The section then describes how these are further developed to provide forecasts of future demand and generation connected to our networks. This becomes the starting point for our strategic development process.

3.1. The national FES framework

National Grid Electricity System Operator (ESO) produce an annual set of Future Energy Scenarios considering decarbonisation pathways to Net Zero. These are published in July each year.

The FES scenario framework is based on two key axes: decarbonisation speed and societal change level, as summarised in Figure 4. Whilst some scenarios see similar or aligned projections in the near, medium or even long term for some technologies, other aspects of the energy system have very different outcomes. A description of each of the scenarios can be found below.

- **Falling Short:** Does not meet GB net zero targets by 2050. Decarbonisation still progresses however is slower than in the other scenarios. While home insulation improves, there is still heavy reliance on natural gas, particularly for domestic heating. Electric Vehicle (EV) take-up grows more slowly, displacing petrol and diesel vehicles for domestic use.
- **System Transformation:** Meets GB net zero targets by 2050. The typical domestic consumer will experience less disruption as more of the significant changes in the energy system happen on the supply side, away from the consumer.
- **Consumer Transformation:** Meets GB net zero targets by 2050. The 2050 net zero target is met with measures that have a greater impact on consumers and is driven by greater levels of consumer engagement. A typical homeowner will use an electric heat pump with a low temperature heating system and an EV.
- **Leading the Way:** Meets GB net zero targets by 2047. Assumes that GB decarbonises rapidly with high levels of investment in world-leading decarbonisation technologies. Consumers are highly engaged in reducing and managing their own energy consumption.

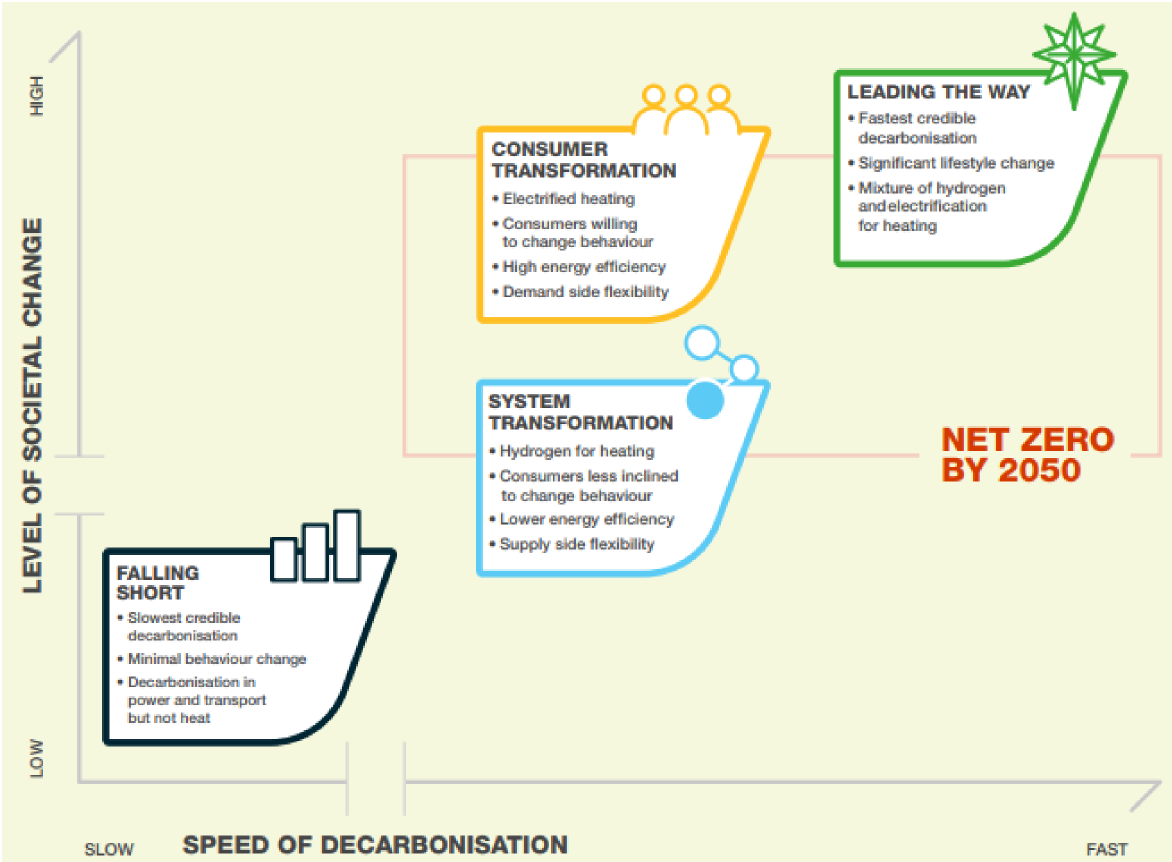

Figure 4 – FES 2022 Scenarios

For the purposes of the NDP, we provide the forecast for all scenarios represented in Figure 4 within our NSHR. When reading the NSHR the following acronyms are used:

Scenario	Acronym
Falling Short	FS
Consumer Transformation	CT
System Transformation	ST
Leading the Way	LW

SSEN Distribution regards the CT scenario as the current “best view” and most likely scenario outturn. This is supported by stakeholder feedback and is reviewed annually.

3.2. Development of DFES

We produce our DFES annually, utilising the new FES as a starting point. Relevant FES data is provided for DFES production through a series of standardised building blocks as per a predefined national process.

Whilst these building blocks provide a starting point we need to more greatly understand the detailed future needs of our communities and stakeholders. We do this through a number of channels:

- **The Connections Pipeline** – 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. We therefore build a dataset of these requirements from our connections database and by direct discussion with developers and stakeholders.

- **Regional analysis** – Investigative work to understand at a local level;
  - 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.

- **Stakeholder engagement** – We approach Local Authorities and other key stakeholders to understand their future energy needs. Each Local Authority is asked to provide data to evidence their future needs and these are built into the DFES projections. selection, with each being assessed in accordance with an open and transparent evidence assessment framework.

It takes between six to nine months to produce the DFES each year. Underlying data is published on our data portal, and summary reports on our website. These summary reports also provide greater detail on our DFES process and the factors considered.

We have used the latest available DFES to produce both the data within the NDR and NHR. For this NDP this is the 2022 DFES as published in April 2023.

3.3. Deriving Load Estimates

To forecast load growth within the SHEPD and SEPD licence areas, it is critical to identify the existing load on these networks, both for demand (import), and generation (export). Once identified, these existing loads are referred to as 'baseline' load for which future growth, from the DFES, is added on top of. Whilst these calculated values do consider seasonal differences, they are calculated as the 'worst cases' of the network within the previous year.

For the demand baseline calculations, or importing from the substation, the peak demand profile of each Primary and BSP substation for each season (Winter, Summer, Spring and Autumn) is identified from the previous year's measured data and consists of 48 half-hourly average readings, which represent a 24-hour period. Figure 5 below shows an example baseline demand profile for each season. These half-hourly readings correspond to the day where the peak demand of each substation occurred for each season. These demand values account for downstream generation where monitoring is present by adding this to the net reading from the substation. For generation capacity that does not have monitoring, output assumptions are made based on generator type, region and time of day. For generation baseline, a net value of minimum demand, maximum generation is calculated. The minimum demand value is calculated in a similar method to the maximum demand outlined above.

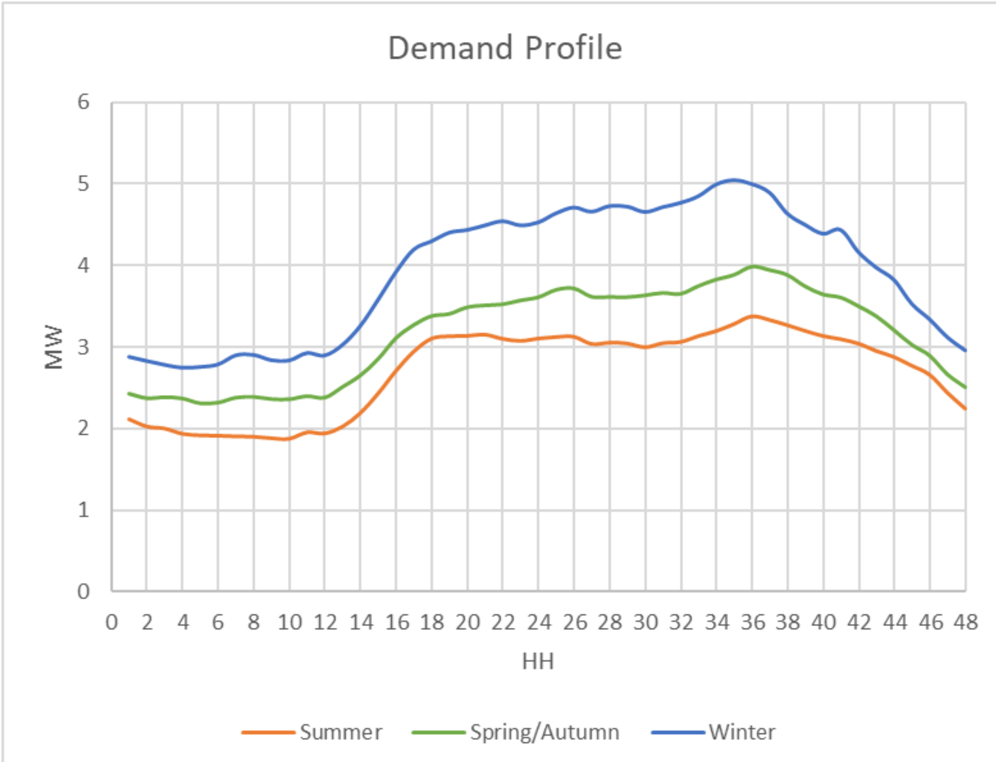

Figure 5 - Typical Demand Profile

Where available, FES grid supply point (GSP) projection data has been used to provide an SSEN DFES to FES reconciliation. Regional building blocks were sometimes unavailable or not directly comparable due to the sub-technology division. In these cases, national FES projections have been used for reconciliation.

3.4. Demand Profiles

With the baseline data and technology projections for all seasons and scenarios up to 2050, we are able to model expected future demand using a number of diversified profiles for each technology. These include connected capacity of storage and low carbon demand technologies, as well as projections for new housing growth and new commercial and industrial developments at each substation up to 2050, for both licence areas. More specifically, the key demand technologies which are utilised by SSEN Distribution to produce the forecasted peak demand profiles for each substation are as follows:

- Electric Vehicle Chargers (Domestic off-street, Domestic on-street, Workplace, Fleet, Enroute local, Destination, Car Park)
- Domestic Heat Pumps (Hybrid, Non-Hybrid)
- Domestic Direct Electric Heating
- New Developments (Domestic, Factory and Warehouse, Hospital, hotel, Medical, Office, Other, Restaurant, Retail, School & College, Sport & Leisure, University, Data Centres)
- Air Conditioning
- Battery Storage (Standalone Grid Services)

A seasonal half-hourly demand profile is produced for each demand and storage category listed above. These profiles are combined with the installed capacity projections for demand at each substation.

The aggregated power profiles of the projected installed capacity of demand are combined with the baseline peak demand profile of each substation to create its forecasted peak demand profile for each season, for each year to 2050 under all DFES scenarios. The below example shows a winter profile forecast for one substation in the year 2030 and under the CT scenario.

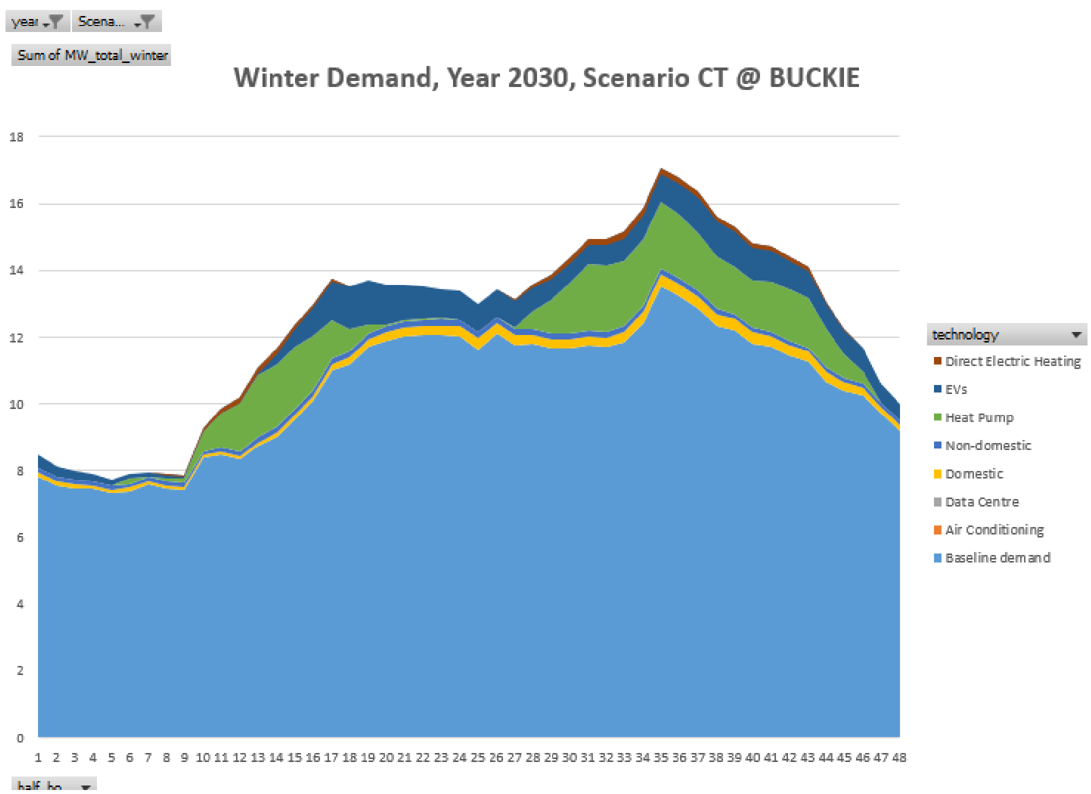

Figure 6 – Future Substation Demand Profile

3.5. Generation Profiles

SSEN's DFES analysis produces scenario forecasts for the connected capacity of distributed generation and storage at each Primary Substation up to 2050, for both licence areas. More specifically, the key distributed generation and storage technologies which are utilised by SSEN Distribution to produce the forecasted net flow profiles for each substation are the following:

- Renewable Energy Generation technologies including:
  - Solar PV
  - Onshore and Offshore Wind
  - Hydropower
  - Marine
- Waste and Bio-Resource electricity generation including:
  - Biomass

    - Sewage and Landfill Gas
    - Anaerobic Digestion
    - Energy from Waste

- Fossil Fuel Electricity Generation technologies including:
    - Diesel
    - Natural Gas

- Battery Storage

A seasonal half-hourly generation profile is produced for each distributed generation and storage category listed above. These profiles are combined with the installed capacity forecasts for distributed generation and storage at each substation.

4. IDENTIFYING LOAD-RELATED NEEDS

4.1. 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.

4.2. 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[3]. We have plans to address compliance issues at several Primary substations classified as exempt in accordance with this alternative standard over the next few years. We are also investigating an innovative solution to increase security of supply in areas where traditional reinforcement, or use of DNO owned standby generation to provide network resilience, is prohibitively costly.

4.3. Identifying load-related needs

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

The methodology used to identify EHV load-related needs is consistent across both licence areas although data has been obtained from separate, network specific DFES projections. Our process combines existing network

3 https://www.ofgem.gov.uk/sites/default/files/docs/2006/04/7806b---notice-pursuant-to-section-11%282%29-of-the-electricity-act-1989-schedule-2-2704_0.pdf

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 assessment. 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 out to 2050 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.

For longer term needs we use power system analysis software to take a higher level view of future system needs across all four DFES backgrounds.

5. OPTIONEERING – THE DISTRIBUTION NETWORK OPTIONS ASSESSMENT PROCESS (DNOA)

This stage in our strategic development process forms a critical part of the process where high level load related needs are developed further to understand and assess network and non-network options. This is our DNOA process with a methodology refreshed annually in consultation with stakeholders[4]. The high level DNOA process is summarised below.

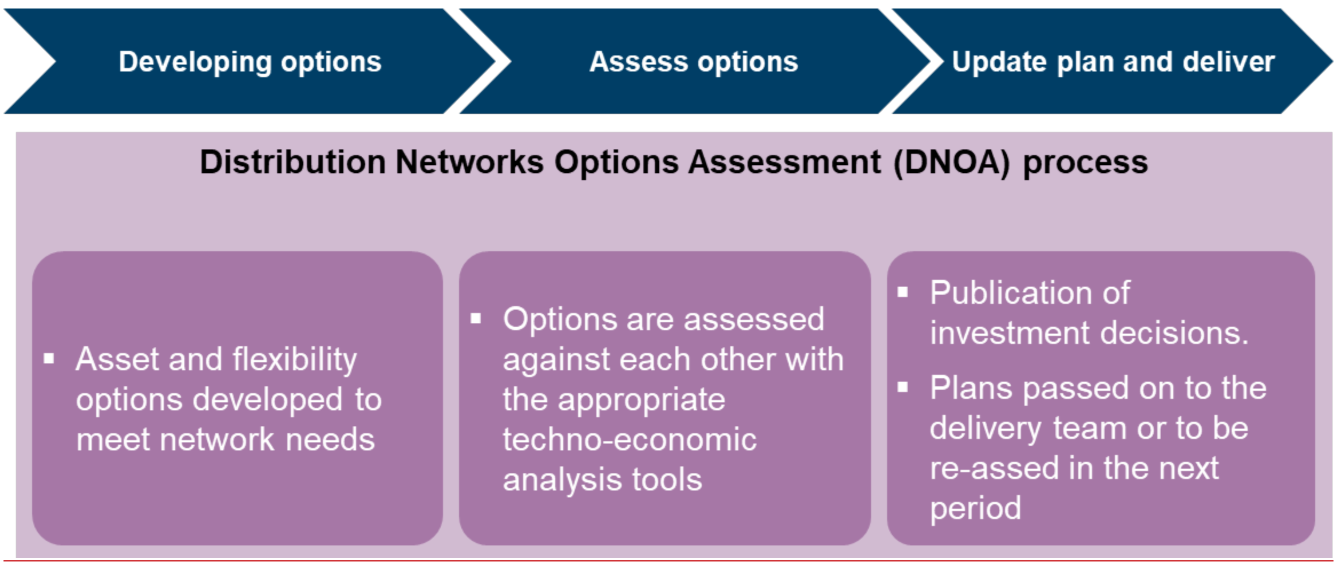

Figure 7 – Distribution Networks Options Assessment (DNOA) Process

5.1. Developing options to meet system needs

For the constraints anticipated across each voltage level studied, and for each credible future pathway, we identify options for providing the capacity shortfall.

In addition to conventional solutions (such as asset-based reinforcement), we ensure that flexibility is prioritised in the assessment and justification process through a flexibility first approach. In this approach –
the application of a flexible solution is considered for all constraints identified on our EHV system, as part of our broader actions on implementation of Whole Systems thinking. On our lower voltage networks, our load-related expenditure proposals take full account of a range of different sources of flexibility.

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).

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

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- Flexible solutions that allow capacity to be released more efficiently.
- 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 RIIOED1.
- Flexible solutions that allow the deferral of any other solution were always considered.

All selected solutions are 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).

5.2. Use of flexibility services

SSEN Distribution has made a commitment to ensure that any future system need must consider the procurement of flexible services. By taking a flexibility first approach, we will be able to accommodate the growth in Low Carbon Technologies (LCTs) and support the changing way our customers use our network, whilst continuing to ensure we meet our obligations to develop and maintain an efficient, co-ordinated and economical distribution system. Procuring flexibility services is a smart and efficient way to manage network capacity, allowing us to respond quickly to future network requirements.

SSEN Distribution have committed to a target of 5GW cumulative capacity of flexibility procured over the five-year RIIO-ED2 price control, beginning with 800MW in year one and reaching over 1GW by year five. In 2023 we introduced a global call for flexibility services across both our license areas to support Flexibility Service Providers (FSPs) who have multiple small assets such as those supplying Demand Side Response (DSR) services. We have successfully signed 8 providers to our Overarching Agreement (8 in Southern Electric Power Distribution (SEPD) and 3 in Scottish Hydro Electric Power Distribution (SHEPD)). This strategy will allow for the rapid deployment of flexibility services, irrespective of which scenario outturns in future years.

5.3. Assessing our options

Currently we justify future network investments through Engineering Justification Papers (EJPs) which are submitted to Ofgem alongside a deterministic Ofgem directed CBA. We use other deterministic CBAs to support investment decisions; the Common Evaluation Methodology (CEM) for flexibility and the Whole System CBA for cross-vector comparisons.

For long term strategic development, we compare the cost and benefits of anticipatory investment alongside the use of flexibility. Depending on the specific case, this can also involve comparison of a number of strategic investment options. These assessments consider the impact of each option out to 2050.

Cost-benefit analysis is reviewed on an annual basis as part of the DNOA methodology. This ensures we are utilising latest information. on flexibility unit costs and may result in acceleration or deferral of strategic investment.

6. NETWORK SCENARIO HEADROOM REPORT METHODOLOGY

This section provides further context on the methodology employed to develop our Network Scenario Headroom Reports.

6.1. Demand Headroom

This section describes the methodology behind the calculation of the available demand headroom at each Primary (66-33-22 kV/11-6.6 kV) and BSP (132-66 kV/33-22-11 kV) substation in the SEPD licence area and each Primary (33/11 kV) substation in the SHEPD licence area. Note that GSP substations (132 kV/33 kV) are not included in the SHEPD licence area as these are classed as Transmission infrastructure.

Given the rapidly changing consumption patterns of new demand and storage technologies, it is becoming more difficult to identify the single worst-case network condition that will determine the available demand headroom of a substation. Therefore, the demand headroom calculation is based on seasonal peak demand profiles with minimum coincident generation, both for the baseline substation demand and the forecasted demand and storage technologies.

The calculated peak value of the demand profile of each substation, from the DFES projections. was then compared with its firm capacity to identify the available demand headroom or deficit.

Based on the above, the demand headroom is defined, per DFES scenarios, per substation, per year (up to 2050), as follows:

Demand Headroom = Substation Firm Capacity – Forecasted Maximum Demand

It must be highlighted at this point that this exercise mainly focuses on the available demand headroom at the substation level only. Within this analysis, the methodology has considered potential circuit limitations for radial circuits since this is considered within the published firm capacity values. However, for highly interconnected ring networks, there is a possibility that the methodology would provide an overestimate of the available headroom, as this might be reduced by circuit limitations. To account for some of the upstream circuit limitations or interconnected networks, the headroom methodology considers any upstream circuit constraints for substation groups which were identified to require reinforcements within the RIIO-ED2 period (2023 – 2028).

Furthermore, the demand headroom at each substation is calculated by considering the diversity between its baseline peak demand profile and the seasonal power profiles for each demand and storage technology projected to connect to this specific substation. This means that we are not using the 'traditional' demand connection assessment which utilises an absolute maximum demand value for both existing and proposed load.

Based on all of the above, it is possible that additional factors might limit the available demand headroom at each substation, which would be identified as part of a formal connection assessment carried out by SSEN Distribution.

It must be noted that there may be upstream constraints beyond the primary substation or bulk supply point due to substation groups or GSP constraints. Upstream constraints are highlighted in within the Network Headroom Report; however, these constraints are not reflected in the headroom capacity values. Where an upstream constraint is identified any new connection will require a detailed system study to determine the actual headroom capacity.

Data

Component	Dataset	Description	Assumptions
Demand	Demand Forecast	Demand projection per substation for the 4 Distributed Future Energy Scenarios (DFES)	Half-hourly profiles for both the baseline peak demand and the forecasted demand and storage technologies
Capacity	Firm Capacity	Current firm capacity per substation taken from the Long-Term Development Statement (LTDS)	The base firm capacity per year per substation is added to any additional capacity that is planned to become available within the RIIO-ED2 Period (2023-2028)
	Planned Released Capacity	New firm capacity which is expected to become available per substation within the RIIO-ED2 period (2023-2028)	
	Transformer Nameplate Rating	The transformer nameplate rating taken from the SSEN Distribution Generation Heatmap dataset	For a number of substations without firm capacity data, the Transformer Nameplate Rating was used as a substitute for Firm Capacity in the Demand Headroom calculation given above. The Heatmap dataset has been used in this analysis as it will be familiar to stakeholders.

Table 3 - Demand Headroom Data & Assumptions

6.2. Generation Headroom

This section describes the methodology behind the calculation of the available generation headroom at each Primary (66-33-22 kV/11-6.6 kV) and BSP (132-66 kV/33-22-11 kV) substation in the SEPD licence area and each Primary (33/11 kV) substation in the SHEPD licence area. Note that GSP substations (132 kV/33 kV) are not included in the SHEPD licence area as these are classed as Transmission.

Given the rapidly changing generation patterns of new distributed generation and storage technologies, it is becoming more difficult to identify the single worst-case network condition that will determine the available generation headroom of a substation. Therefore, the generation headroom calculation is based on seasonal minimum demand profiles with maximum coincident generation, both for the baseline substation demand and for the forecasted distributed and storage technologies.

The aggregated generation profiles of the projected installed capacity of distributed generation and storage were combined with the baseline minimum demand profile of each substation to create its forecasted net flow profile for each season, for each year to 2050 under all DFES scenarios. The net flow through the transformers of a substation can be either forward (negative/demand) or reverse (positive/reverse power flow).

The maximum value of the net flow profile of each substation was then compared with its transformer nameplate rating in order to identify the available generation headroom or deficit.

Based on the above, the generation headroom is defined, per DFES scenarios, per substation and per year (up to 2050), as follows:

Generation Headroom = Transformer Nameplate Rating – Forecasted Maximum Net Flow

It must be highlighted at this point that this exercise mainly focuses on the available generation headroom at the substation level only. Within this analysis, the methodology has taken into account potential circuit limitations for radial circuits, since this is considered within the published transformer nameplate ratings. However, for highly interconnected ring networks, there is a possibility that the methodology would provide an overestimate of the available headroom, as this might be reduced by circuit limitations. To account for some of the upstream circuit limitations or interconnected networks, the headroom methodology considers any upstream circuit constraints for substation groups which were identified to require reinforcements within the RIIO-ED2 period (2023 – 2028), as shown in our Network Development Report.

Potential voltage constraints and upstream transmission constraints have not been considered within the analysis.

Furthermore, the generation headroom at each substation is calculated considering the diversity between its baseline minimum demand profile and the seasonal generation profiles for each distributed generation and storage technology, which is projected to connect to this specific substation. This means that we are not using 'traditional' generation connection assessment, which utilises absolute minimum demand values and maximum existing and forecasted generation output. Therefore, the total generation headroom identified for each substation also includes the available headroom for flexible generation connections.

The above means that it is possible that additional factors might limit the available generation headroom at each substation, which would be identified as part of a formal connection assessment carried out by SSEN Distribution.

It must be noted that there may be upstream constraints beyond the primary substation or bulk supply point due to substation groups or GSP constraints. Upstream constraints are highlighted in within the Network Headroom Report; however, these constraints are not reflected in the headroom capacity values. Where an upstream constraint is identified any new connection will require a detailed system study to determine the actual headroom capacity.

Data

Component	Dataset	Description	Assumptions
Generation	Generation Forecast	Generation projection per substation for the 4 Distributed Future Energy Scenarios (DFES)	Half-hourly profiles for the forecasted distributed generation and storage technologies
Capacity	Transformer Nameplate Rating	The transformer nameplate rating taken from the SSEN Distribution Generation Heatmap dataset. The Heatmap dataset has been used in this analysis as it will be familiar to stakeholders.	Enhanced emergency transformer ratings were not considered as part of this analysis

Table 4 - Generation Headroom Data & Assumptions

6.3. Methodology Assumptions

Overall Methodology Assumptions

- Available Demand and Generation headroom was calculated at the substation level only.
- Within this analysis, the methodology has taken into account potential circuit limitations for radial circuits, since this is considered within the published firm capacity values. However, for highly interconnected ring networks, there is a possibility that the methodology would provide an overestimate of the headroom as circuit limitations may reduce the headroom at substations. To account for some of the upstream circuit limitations:

- The headroom methodology considers any upstream circuit constraints for substation groups which were identified to require reinforcements within the RIIO-ED2 period (2023 – 2028), please see our Network Development Report.
- This is done by adjusting the generation and demand capacity, as well as generation and demand at affected substations, to produce an illustrative headroom which incorporates upstream circuit limitations.

- Upstream transmission constraints are shown as a “Yes” or “No” however their impact on capacity is not considered in the headroom calculation.
- When firm capacity was not available, the transformer nameplate rating was utilised for the calculation of the demand headroom
- The combination of half-hourly baseline demand profiles and half-hourly power profiles for each demand, distributed generation and storage technology were used to calculate the available demand and generation headroom at each substation.
- Regarding the fault level calculations, it must be highlighted that at most sites, not all circuit breakers would be subject to the fault currents provided.

6.4. Limitations

As stated in the assumptions above, the available demand and generation headroom was calculated at the substation level only. Upstream thermal capacity limitations have been considered by adjustments to generation and demand capacities as well as demand and generation for any substations requiring investment in the RIIO-ED2 period as determined by our “best view” scenario: Consumer Transformation.

Additionally, headroom calculations consider the diversity between substation baseline demand profiles and the half-hourly profiles for each demand, distributed generation and storage technology, making this analysis different from using maximum values as per our ‘traditional’ connection assessments. Based on the above, especially for the generation headroom, the values calculated also include the headroom for flexible generation connections.

Given the points raised above, it is highly likely that additional factors might limit the available demand and generation headroom at each substation, which would be identified as part of a formal connection assessment carried out by SSEN Distribution.

The information presented within the NDP is accurate at the point of publication. Future forecasts under the DFES may differ over time as a consequence of government policy, a change in consumer habits, changes to generation portfolio through new connections etc. In addition, our proposed investments may change because of changing forecasts and agreed allowances as set by Ofgem as part of each Distribution Price Control period. Although the NDP provides a view of the future in terms of our investments and potential network constraints; we would encourage any party using this information in their decision-making process to engage with us ahead of lodging an application to connect or offer flexible services.

Scottish & Southern
Electricity Networks

CONTACT

whole.system.distribution@sse.com
www.ssen.co.uk
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