

# Network Development Plan Methodology

May 2026



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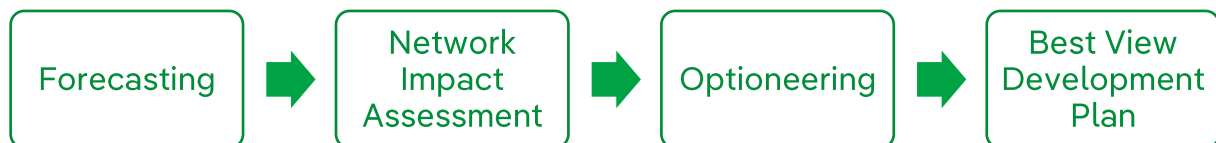
# 1. Purpose of the NDP methodology document

This Network Development Plan (NDP) methodology document serves to provide transparency and guidance on how the network forecasting and development process for the provision of network capacity is undertaken within SP Electricity North West and therefore how the NDP is compiled. For detailed insight into how the calculations in the Network Headroom Report are derived, please see the accompanying guidance document specific to that. The NDP methodology covers the end-to-end network planning process with sufficient detail to allow stakeholders to understand the approach taken and any associated sensitivities and considerations of the process.

## 2. Overview of network planning process

SP Electricity North West's approach for capacity-related network planning follows a systematic end-to-end development process, as shown in Figure 1, and this document describes the methodology applied at each step.

*Figure 1: High level capacity-related network planning methodology*



Forecasts of credible futures are an essential starting point as customers' requirements are expected to continue to change within an evolving energy system influenced by net zero targets. These alternative views of the future allow us to prepare for a range of eventualities including different levels of low carbon technology (LCT) uptake. Analysis of demand and generation forecasts informs our understanding of where our network will have sufficient capacity and how this varies for each scenario.

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

All steps form part of the ongoing processes using standard network data to reach consistent views of our network capacity as reflected in our standard reports which are published to support our stakeholders. These can be accessed via our [Open Data Portal](#) including, but not limited to, the:

- Embedded Capacity Register (connections data)
- Distribution Future Electricity Scenarios (DFES) (load and generation growth forecasts)
- Capacity heatmaps (HV heatmaps, NDP capacity headroom data, heatmap tool etc)
- Long-Term Development Statement (LTDS) – focus on a one to five year horizon
- Network Development Plan (NDP) – focus on a one to ten year horizon.

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

- Section 3 outlines the basis and development of the regional scenarios that have informed our best view investment plan for the next ten years that embeds the transitional Regional Energy System Plan (tRESP) from the National Energy System Operator (NESO)

- Section 4 explains the next step and how we assess the impact of forecast electrical requirements on our network
- Section 5 presents the solutions we apply including use of flexibility and discusses our decision-making processes
- Section 6 discusses how we have prepared our investment plan.

## 3. Forecasting

### 3.1. Overview

A wide range of long-term forecasting scenarios for electricity demand and distributed generation growth are used in network planning. The DFES 2025-2026 published in March 2026 are the drivers of the load-related investment requirements defined in our 2026 NDP report.

At a high level our Best View scenario is used to assure near-term licence compliance and risk management, while the National Energy System Operator (NESO) transitional Regional Energy System Plan (tRESP) pathways, common planning assumptions and strategic energy needs (SENs) are used for strategic alignment and regulatory baseline signalling.

The Holistic Transition scenario from our DFES, which embeds the tRESP pathways, common planning assumptions and SENs, published by NESO in January 2026, is what we will refer to hereafter as the 'tRESP scenario' in this document.

The tRESP scenario uses the future trends from NESO's tRESP Holistic Transition pathway and the granular forecasts from our DFES Holistic Transition scenario produced following NESO's tRESP guidance granular pathways. The GSP pathways for the tRESP building blocks (LCT volumes, renewable capacities etc) were produced by NESO using the DFES Holistic Transition scenario forecasts and their adjustments considering Clean Power 2030 and carbon budget considerations and data.

To get more confidence in the tRESP scenario we have adopted the highest certainty assumptions for local stakeholder plans (aligned with the Best View scenario), including existing connection applications and longer-term plans, including the tRESP SENs.

Our DSO forecasting and the use of our DFES scenarios is still critical not only in the production of the tRESP scenario with inputs from NESO, but importantly as an assurance check that allows us to meet our licence obligations for security of supply and economic network development. As such the use of our Best View scenario, that follows the standardised [ENA methodology](#), is fundamental to this process.

The Best View scenario adopts the highest certainty assumptions in demand and generation forecasts up to 2030. The electrification of transport and heating are the main paths. This is an SP ENW scenario based on our understanding and stakeholder insights of what the future is likely to look like in the next ten years. Based on the ongoing analysis of the pathways provided by tRESP, this is the scenario that shows the strongest alignment with the tRESP scenario, on which both our NDP report and the ED3 business plan will be based. However, it should be noted that our ED3 business plan submission will embed the latest inputs from NESO's tRESP as part of the data validation for SENs as well as Ofgem's final guidance.

### 3.2. DFES scenarios

All DNOs undertake an annual forecasting activity which is presented in their respective annual DFES publications. DFES provides granular scenario projections for electricity demand,

distributed generation (DG) and battery storage that incorporate regional factors and can be used at a local level for strategic planning of distribution networks. These projections are informed by local stakeholder engagement to understand the needs, plans and delivery progress of local authorities and other stakeholders. The DFES provides an evidence base for the DNO to develop the business case necessary to support future investment, including regulated business plans.

As part of our 2025-2026 DFES we have produced a set of seven scenarios: tRESP scenario (building on Holistic Transition), Best View (BV – ENA standardised), Holistic Transition (HT), Electric Engagement (EE), Hydrogen Evolution (HE), Falling Behind (FB) and Accelerated Decarbonisation (AD – not part of the FES-DFES aligned scenarios). Following the whole system FES standardisation process developed in Workstream 1B Product 2 of the ENA Open Networks project, the HT, EE, HE and FB scenarios have the same scenario framework, names and high-level assumptions as NESO's FES and all other DNOs' DFES.

The real value of this standardisation is to create a common language and familiarity for stakeholders when accessing electricity demand and generation forecasts from multiple organisations. For example, the use of this common language means that high uptake trends of electric vehicles (EVs) should be expected for HT across the industry. However, this does not mean that these trends follow the same pattern or volume across all regions or between regions within the same licence area. Engagement with local stakeholders and the influence of distribution network planning on stakeholder decisions allows us to improve the accuracy of regional forecasts.

Further information on the methodologies we employ in the creation of our DFES forecasts is available on [our website](#).

Even though stakeholder engagement has allowed us to model evidence-based local plans in DFES, it has also revealed that local policies are not yet in place to accelerate decarbonisation to meet net zero carbon targets before 2040. Therefore, all seven scenarios in our DFES 2025-2026 are driven by national policies and local factors reflected through our cycle of engagement with local stakeholders and ATLAS bottom up forecasting methodologies. Apart from the FB scenario, all scenarios meet the UK government's 2050 net zero carbon target with Accelerated Decarbonisation meeting it by 2045.

### 3.2.1. Forecast parameters

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

- LCT volumes
  - EV volumes (cars, vans and heavy-duty vehicles)
  - Heat pump volumes
- DG and battery storage capacities
  - Photovoltaics (PV)
  - Wind generation (onshore)
  - Batteries (grid scale and domestic)
  - Other generation types (incl. Gas fuelled, hydro)
- Penetration of other key technologies that affect electricity demand
  - District heat networks
  - Hydrogen electrolyzers
  - Air conditioning
  - Data centres

- Residential developments (new housing, retrofits on existing building stock)
- New economic growth developments
  - Commercial developments
  - Industrial developments
  - Electrification of existing industrial processes currently fuelled by other fuel types (predominantly gas)
- Electricity demand
  - Electricity (energy) consumption
  - True peak demand

### **Focus on true demand**

The true demand is the demand that needs to be supplied at a local level if local generators are not exporting, e.g. due to maintenance or low wind for wind farms. It is particularly important in distribution networks for numerous reasons:

- Local demand is less diversified than at the national transmission level, e.g. in FY20 the sum of individual primary substation peaks in our South Manchester group was a third more than the peak demand for the group observed at the transmission interface. Diversity is even lower in the HV and LV parts of our distribution network that are closer to customer points of connection.
- Distribution network security of supply assessments in accordance with EREC P2/8 (licence condition) require consideration of local true (gross) demand as a minimum. An allowance for the contribution of local generation to security of supply is modelled following EREC P2/8 considering that local generation is less diversified as we move to lower voltage levels. The allowance is typically significantly less than the sum of the generators' rated capacity values.
- Demand forecasts produced with a transmission or capacity market focus, e.g. NESO FES, can be inclusive of the diversified effects of small local generators that appear to reduce the consumption of distribution network customers because they are used to determine the level of demand that needs to be supplied via the transmission network, rather than the local distribution network.

## **4. Network impact assessments**

### **4.1. Overview of network impact assessments**

Our forecasts for electricity demand and distributed generation and battery storage are used as inputs in network impact assessments. These assessments allow us to understand if future requirements for power on different parts of the network can be supplied by the existing network capacity or if interventions are required to accommodate demand and generation growth.

#### **4.1.1. Introduction to network impact assessments**

Network impact assessments are carried out for both the extra high voltage (EHV – 132 to 33kV) and secondary (11 to 0.4 kV) networks to determine future network development plans and investment requirements. Different approaches are applied at different voltage levels due to the differing size, demand diversity, volume drivers and complexity per voltage level.

Our approach to assess EHV and HV network impacts are detailed in this section of the methodology document and reflect the approach taken for the Network Development Plan Report. For a given scenario network impacts are based on forecasts per substation and detailed power system modelling (i.e. using IPSA power system analysis software). This analysis allows us

to locate where network parameters exceed limits including thermal, voltage and fault level, while also allowing us to analyse and compare the effectiveness of alternative solutions. This analysis is complemented with the consideration of connection applications so that the scenario-based analysis and the connections-driven reinforcement requirements are combined to facilitate co-ordinated network development.

Our approach to assess LV network impacts for a given scenario is based on the use of our bespoke Future Capacity Headroom (FCH) tool to quantify thermal and empirically voltage issues. This approach allows us define LV requirements at programme level and in ED2 define the proactive investment programmes for secondary substations (typ. 11 or 6.6/0.4kV). To facilitate co-ordinated LV network development, our latest policies for LV demand connections require the consideration of a ten-year DFES forecast for EVs and heat pumps.

#### **4.1.2. Network data for impact assessments**

A number of key data sources are used in our network analysis that underpins our RIIO-ED2 load-related investment plan. Our Master Asset Management System (MAMS) database contains a corporate auditable record of our transformer and switchgear ratings, on which our system study models are built. Cable records are contained in our GIS system and again the master modelled data is verified against this source and based on these corporate records. Future demand and generation data is from our detailed DFES scenario forecasts which have been produced for our licence area. Our Long-Term Development Statement and published DFES report are also key sources of information for our detailed study work.

For the modelling of our EHV network in impact assessments, the detailed electrical parameters of all EHV assets, i.e. impedance and susceptance values for transformers, lines and cables, as well as operational aspects, e.g. on-load tap changer settings and voltage targets, are modelled in an IPSA power systems analysis tool. Our IPSA network model exceeds 3,000 nodes and covers the whole 132kV and 33kV network and incorporates an equivalent reduced network representation of the transmission network, including detailed information on transformers and circuit ratings. Our IPSA models now cover the HV network (over 3,000 feeders) and facilitate detailed studies across the 11 and 6.6kV networks.

The HV (empirical) and LV network impact assessments are undertaken using our tailored FCH tool (v2) which models the actual connectivity of the whole HV and LV networks (over 300,000 nodes including over 35,000 secondary substations) and allocates half-hourly loading to the whole of the network from the most remote LV feeder sections up to the monitoring points at the heads of HV feeders (over 3,000 feeders in our licence area).

#### **4.1.3. Use of forecasting scenarios in network planning**

The tRESP scenario aims to provide clarity and remove the complexity of multiple scenarios for our customers and stakeholders, as long as it is aligned and validated with our Best View scenario. As the region's highest certainty scenario when compared to three key criteria, our Best View scenario provides the highest certainty basis for assessing network impact and the need for interventions in the next ten years. Therefore, the tRESP scenario has been used as the basis to present future asset requirements in our Network Development Plan, whereas the corresponding flexibility service requirements in the longer term are presented for the Best View, Holistic Transition and Falling Behind scenarios to indicate the potential longer-term range.

When developing the Best View investment plan driven by the tRESP scenario for the next ten years as presented in the Network Development Plan Report, we have used the tRESP scenario for the presentation of requirements, but importantly we use the other DFES scenarios to enable a sensitivity analysis when considering the magnitude and timing of constraints. The DFES

scenarios are useful to help define this range of uncertainty even in the near term, and are used to ensure that options for responding to an uncertain future are not foreclosed. Any investment decision made is based on the observed network conditions and local stakeholder information at the time.

## 4.2. EHV network impact assessments

### 4.2.1. Thermal and voltage issues

Thermal assessments of our EHV network loading are undertaken in two stages: an initial approximate assessment is followed by more detailed studies where required. The forecast peak demand for each year up to 2034/2035, i.e. covering the ten-year period of the Network Development Plan Report, is compared to the existing firm capacity of each EHV substation, i.e. all BSPs and primary substations. This comparison is carried out for the tRESP scenario. Should the anticipated demand growth approach a substation's firm capacity, detailed studies are undertaken to explore the issue further. We use our IPSA models to study our 132 to 33kV network down to primary substation HV busbar level.

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

Our Network Development Plan is based on interventions being required when thermal capacity exceeds existing firm capacity ratings. This level has been selected for its alignment with Ofgem's Load Index 5 definition and signposts interventions over the ten-year NDP period to ensure there is sufficient time to initiate planning and development of whole system solutions.

### 4.2.2. Short circuit studies

EHV and primary substation HV fault levels are simulated using our network models. More specifically, fault level studies are carried out using our IPSA model to calculate break and make fault levels. The fault level assessments are performed at each BSP and primary substation and for each future year of the forecasting scenarios. The fault level results are then compared with switchgear ratings to calculate the fault level headroom at a given location for each year of the forecast scenarios.

The main impact on 33kV fault levels comes from the large accepted generation schemes that are embedded in the forecasting scenarios and their location can be critical for the fault levels assessed across the network.

Our Network Development Plan is based on interventions being required when fault levels exceed 100% of existing switchgear 'make' and 'break' ratings.

## 5. Network Solutions

### 5.1. Network development planning

Comprehensive optioneering is undertaken following the identification of network issues through our network impact assessments. Alternative approaches are thoroughly assessed to ensure that the optimal development plan is identified, considering the timing of interventions and not

foreclosing future pathways. For development of the EHV network, this is supported by use of rigorous cost benefit analysis which ensures that flexible solutions are considered equitably alongside traditional asset solutions.

## 5.2. EHV network development

### 5.2.1. EHV load-related interventions

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

Typical solutions include:

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

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

### 5.2.2. EHV fault level interventions

Fault level management is a critical network safety factor examined by our network impact assessments. When exceedances are identified, planned interventions traditionally take the form of making replacements with higher rated equipment, but we could also adopt a non-traditional innovation solution which does not require the switchgear to be replaced. This could be a network rearrangement to lower fault level or it could be the implementation of an innovation project such as Respond. Selected solutions are based on proven techniques which we consider to be deliverable solutions within the required time period of a project, based on an acceptable equipment outage, consents and acquisition risk.

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

### 5.2.3. Flexibility services approach

SP Electricity North West has a flexibility first approach to network development when a capacity need is identified. In practice this means that for every capacity requirement we evaluate a traditional asset-based solution against the option of flexibility services.

Our approach to the use of flexibility services to support a capacity requirement can be two-fold: flexibility services can be a key interim solution while we assess load growth and a wider strategic conventional reinforcement, therefore avoiding inefficient piecemeal network expansion and stranded assets. Alternatively, flexibility services allow us to mitigate the risk if demand growth is accelerated and there is a long lead time associated with asset-based

interventions. In some instances, depending on the level of the flexibility market in the location of the capacity requirement and the scale of the capacity requirement, flexibility services could be considered as an enduring network solution.

Our ten-year best view Network Development Plan is presented in this report and shows the future view of asset solution requirements driven by the tRESP scenario. At the same time we signpost the long-term needs for flexibility services. Half-hourly through year capacity balancing requirements across our EHV network can be identified using the detailed assessments supported by our ATLAS forecasting methodology. This allows us to define detailed flexibility requirements, such as number of days per month, energy requirements per day and capacity requirements per season to procure the required capacity of flexibility services only when they are needed.

The identified flexibility service requirements (including LV flexibility services) are aligned with our latest DFES and are issued to the market via numerous channels including monthly flexibility tenders. Following the closure of each flexibility tender, bids are assessed to determine their technical and economical compliance and a cost benefit analysis undertaken to compare the proposed flexibility to all alternative solutions.

#### **5.2.4. Considering synergies**

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

Bi-annual reviews of connections activity outside of the DFES process are also undertaken to identify regions with high levels of connections activity which may trigger strategic reinforcement. Flexibility can then be used to mitigate risks associated with the potential that actual demand growth associated with the connections pipeline materialises beyond the expected based on historical performance that informs the confidence factors used in the forecasts.

In the development of efficient network plans, a joined up whole systems approach utilising customer and stakeholder partnerships will always be explored. Co-ordination and collaboration with regional stakeholders, industry and other energy providers is key to developing low cost whole systems outcomes. We will continue to foster our flexibility first approach; this shows our intention to develop flexible options utilising customer capabilities. We utilise data exchange activities and joint liaison meetings with other network operators to identify and analyse where there may be synergies between our capacity requirements and the opportunity to develop cross boundary solutions.

## **6. Best view development plan**

### **6.1. Decision-making and use of CBA**

To select the best view solution for a project for incorporation into a strategic investment programme, the full range of solutions for that project as identified in the optioneering process are compared. Apart from an element of optimisation in terms of a quantitative minimisation of costs and risks among solutions, an element of judgement is applied in our decision-making to ensure that multiple vectors are taken into consideration to allow us to decide after seeing the

'full picture'. To do that we need to consider practicalities and other qualitative factors to complement the quantitative analysis.

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

- For all proposed EHV asset solutions the Common Evaluation Methodology (CEM) tool developed in Open Networks and including Ofgem's RIIO-ED2 CBA has been used to compare them with flexibility and other alternative options.

## 6.2. Timing and uncertainty

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

Local authorities (LAs) in our region have committed to decarbonisation targets which are more ambitious than the government's 2050 net zero emissions target enshrined in law. Both Cumbria County Council and Greater Manchester Combined Authority (GMCA) have announced their intention to reach net zero carbon by 2037 and 2038 respectively. This is in addition to other county and borough councils in our region declaring a climate emergency as part of their actions to avert a climate crisis. These moves by our regional governing bodies and the steps already being taken by local organisations are clear indications of the commitment to accelerated decarbonisation. However, we cannot be as certain of the rate and extent of local transformation without central government funding and the ability to change policies to influence the transition. For this reason, our best view Development Plan presented in the NDP and driven by the tRESP scenario considers developments contained within our DFES that have strong supporting evidence from LAs and have UK government backing and secured funding. This enables us to ensure a holistic approach and avoid piecemeal network development that is driven by reacting passively to connections activity.

Our published Network Development Plan is our best view of what we expect will be required during the coming ten-year period and therefore in advance of when decisions are usually made. Therefore, project development plans are regularly reappraised on an annual basis using the most up-to-date actual conditions and forecasts to ensure their requirements are still valid and the solution is the most efficient. Investment plans are scrutinised as part of this process to assess whether they still provide the optimal way forward and will deliver the necessary benefits at the required time.

This way we ensure that our plans flex to reflect the changing energy landscape and network requirements. As with all capacity shortfalls, the market is tested at that time to determine if a flexibility service can be obtained to provide a solution and the associated cost, so that a fair comprehensive cost benefit analysis can be used to compare with more traditional asset-based interventions to establish the most efficient solution to be taken forward.