Long Term Development Statement

SP Distribution

for the years 2023/2024 to 2027/2028

Contents

The information used to compile this Statement is derived from SP Distribution plc's own data. Whilst all reasonable care has been taken in the preparation of this data, SP Distribution plc is not responsible for any loss that may be attributed to the use of this information.

The Distribution Long Term Development Statement has been prepared by SP Distribution plc in accordance with Condition 25 of the Electricity Distribution Licence, issued under the Electricity Act 1989. The Statement is prepared in a form specified by the Gas and Electricity Markets Authority.

Registered Office: 320 St. Vincent Street, Glasgow G2 5AD

1. Part 1: Introduction

1.1. Who We Are

We are SP Energy Networks, part of the ScottishPower Group of companies. We own and operate three electricity network licences:

- SP Transmission plc (SPT) is responsible for the transmission network in central and southern Scotland.
- SP Distribution plc (SPD) is responsible for the distribution network in central and southern Scotland.
- SP Manweb plc (SPM) is responsible for the distribution network in Merseyside, Cheshire, North Wales, and North Shropshire.

It is through these networks of underground cables, overhead lines, and substations that we provide, on behalf of supply companies, 3.5 million homes, businesses, and public services with a safe, reliable, and efficient supply of electricity.

1.2. Purpose of the SP Distribution Long Term Development Statement

The Long Term Development Statement (LTDS) provides information on the operation and development of our 33kV and 11kV distribution network in our SP Distribution licence area. This includes a range of information such as network asset technical data, network configuration, geographic plans, fault level information, demand and generation levels, and planned works. This information is contained in attached Excel and pdf files which, together with this summary document, form the LTDS.

The purpose of the LTDS is to provide information on the distribution system that may be of use to developers wishing to connect to, or make use of, the distribution system. The data is provided to enable developers to identify opportunities and carry out high level assessments of the capability of the network to support their demand or generation development. Future network development plans are included to advise existing and potential users of significant changes to the system, which may have an impact on their development plans.

A main update is published every November with a minor update every May.

1.3. How the LTDS Fits with Other Data Provision

Publishing our LTDS is just one measure we're taking to increase the transparency of how we plan and operate our distribution network, and is aligned with our approach of sharing an increasing range of network data with stakeholders. Other ongoing data provision includes:

- Distribution Future Energy Scenarios (DFES)[1] – these are forecasts for key customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK & devolved government targets and other industry forecasts. Given the uncertainties out to 2050, we create forecasts for four main energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback. We update our DFES annually.
- Network Development Plan (NDP)[2] – the primary objective of the NDP is to provide information on available network capacity to accommodate demand and generation growth, and interventions the DNO plans which will increase network capacity (such as flexibility use and reinforcement). The NDP is a medium-term outlook and is designed to sit between shorter-term LTDS and long-term DFES.
- Embedded Capacity Register (ECR)[3] – previously known as the System Wide Resource Register, this provides information on generation and storage resources (≥50kW) that are connected, or accepted to connect, to our distribution network. It is updated on the 10th working day of each month.
- Heatmaps[4] – this interactive mapping tools provides a geographic view of where there is available network capacity to accommodate new generation.
- Flexibility tenders – we tender for flexibility for all viable network constraints. When we run tenders we publish information on the location, magnitude, and duration of the constraint. In some cases, we will also send ceiling price information. We run tenders twice annually.

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[1] Our DFES is available here:
https://www.spenergynetworks.co.uk/pages/distribution_future_energy_scenarios.aspx
[2] Our NDP is available here:
https://www.spenergynetworks.co.uk/pages/network_development_plan.aspx
[3] Our ECR is vailable here:
https://www.spenergynetworks.co.uk/pages/embedded_capacity_register.aspx
[4] Our heatmaps are available here:
https://www.spenergynetworks.co.uk/pages/connection_opportunities.aspx

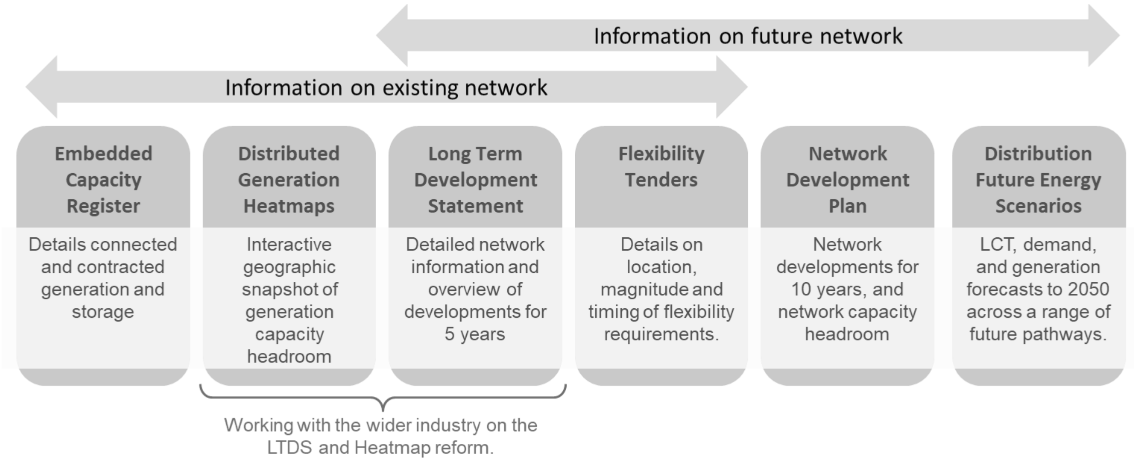

Figure 1: How our LTDS fits with other data provision

We are working closely with our regulator Ofgem and the industry to identify ongoing improvements and reforms to LTDS. This includes formalising and finalising the use of Common Information Model (CIM) as the expected standard for data exchanges in the energy industry. We will ensure our publications are aligned with the latest developments and requirements from this national working group.

Information on how to connect a generation scheme onto our network can be found on our website[5].

Looking forward, given the value of data share, we plan to share a wider range of historical, near-time, real-time, and forecast data with stakeholders. This will be underpinned by infrastructure to gather, assess, and share data, and engagement with stakeholders to prioritise data publication. Please see our Open Data Portal[6] for more information on the network data we share and our Data Strategy.

1.4. An Introduction to the SP Distribution Network

The SP Distribution network supplies nearly 2.02 million customers in Central and Southern Scotland. The geographical area extends from Stirling in the North, Glasgow and Ayr in the West, Edinburgh in the East and Dumfries & Galloway in the South, covering an area of over 21,905 km^2. Electricity is taken from SP Transmission's 400 kV, 275 kV and 132 kV networks and distributed to our customers though a succession of networks operating at 33 kV, 22kV, 11 kV, 6.6kV and 400/230 V. There are also connections to Scottish & Southern Electricity Networks in the North and to an area around Berwick-upon-Tweed to the South of the Border.

[5] Available here: www.spenergynetworks.co.uk/pages/getting_connected.asp
[6] Our Open Data Portal. Available at: https://spenergynetworks.opendatasoft.com/pages/home/

SP Distribution Network Overview

Distribution voltages

33 kV, 22 kV, 11 kV, 6.6 kV, 400/230 V

Assets (HV and above)

Overhead lines:	16,190 km
Underground cables	16,484 km
Transformers	42,857

Customers

2.02 million customers

System max demand:	3.25 GW
Connected generation:	2.65 GW
Contracted generation:	7.80 GW

Customer demand on the distribution system and the operation of generators are dynamic in nature and are dependent on many factors. The weather, dawn/dusk times, social or sports events, and relative fuel cost all play a part in shaping the load profile and generation patterns. The demand on the SP Distribution system varies throughout the day and over the seasons. Peak demand on the system generally occurs on a weekday in mid-winter and the minimum demand at the weekend during summer. The maximum system demand for the SP Distribution area for 2022/2023 was 3,250 MW on 14 December 2022 for the half hour period ending 17:00 hours.

Looking forward, our DFES forecasts a considerable increase in the medium to longer term driven by the electrification of customer heat and transport and increases in industrial and commercial load. We are also going to see a further leap in embedded renewable generation to power these. We will need to use a range of intervention types to accommodate this growth, included flexibility services, smart solutions, energy efficiency, network reinforcement, and new innovative solutions.

1.5. Content of the Long Term Development Statement

The Long Term Development Statement consists of the following content:

Part 1: Introduction

Part 2: Summary Information

- Network long term vision
- Design and operation philosophies of the network
- Network characteristics
- Indication of geographical arrangement of the network
- Statutory obligations and industry standards
- References to engineering recommendations and SPEN documentation
- Contact information

Part 3: Detailed Information

- Schematic diagrams detailing the normal operation of the distribution network
- Table 1: Circuit Data
- Table 2: Transformer Data
- Table 3: System Loads

- Table 4: Fault Levels
- Table 5: Embedded Generation
- Table 6: Connection Activity
- Table 7: Substation Abbreviation Codes
- Table 8: Predicted Changes
- Table 9: System Schematics
- Table 10: Geographic Plans

Part 4: Development Proposals

- Network development proposals
- Connection request statistics

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1.6. Annual Publication and Obtaining the LTDS

The network changes over time and the data contained within the LTDS include the known and anticipated developments at the data freeze date, usually the end of August each year. The analytical models, which form the basis of the LTDS data, are finalised by the end of October. System maximum demand data and Grid Supply Point (GSP) loads are for the period April to March. The detailed data tables section (Part 3: Detailed Information) is fully reassessed on an annual basis for publication in November each year. A brief mid-year update summary is published in May.

Access to the LTDS requires registration. After registration, the LTDS document and associated data tables are available for download. There is no cost either for the registration or the download – accessing the LTDS is free of charge.

1.7. Engaging with Stakeholders

Stakeholder views are important to us. Throughout RIIO-ED1 we have been engaging with stakeholders and customers to understand our stakeholder's priorities. This covered a wide variety of areas, from storm resilience and flood protection, to improving supplies to poorly served customers, future proofing the network and innovation to provide network capacity information for new customers.

In response to requests, over recent years we have sought to improve the content and data format of the LTDS, it is now more widely accessible with data provided in more convenient formats.

Information on the location of network assets and capacity available can be found using our interactive mapping tool.

We continue to work with Ofgem and welcome stakeholder and customer feedback; please visit our website for further details[7].

1.8. Further Regulatory Information

SP Energy Networks is a regulated business. We must meet certain criteria in order to meet our licence conditions. You can find further details on our website[8].

1.9. Contact Information

Should you wish clarification on any aspect of this document, please contact:

Address: Russell Bryans
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SP Energy Networks
ScottishPower House
320 St. Vincent Street
Glasgow G2 5AD
Email: rbryans@spenergynetworks.co.uk

Please see Section 5.4 for contact details for other parts of SP Distribution and SP Energy Networks (such as new connections) and for other organisations mentioned in our LTDS.

Opportunities exist for the connection of new load or generation throughout our distribution system. System conditions and connection parameters are site specific and therefore the economics of a development may vary across the system. Developers are encouraged to discuss their development opportunities and we will be pleased to advise on connection issues.

[7] Available here: https://www.spenergynetworks.co.uk/pages/stakeholder_engagement.aspx
[8] Available here: https://www.spenergynetworks.co.uk/pages/regulation_guidance_leaflets.aspx

2. Part 2: Summary Information

2.1. Context

All numbers in this Section 2.1 are for SP Energy Networks (i.e. totals for SP Distribution and SP Manweb) unless stated otherwise.

2.1.1. Our Evolving Role

Our customers prioritise four main things in their electricity supply: reliability, safety, cost-efficiency, and the freedom to consume when they want (domestic customers especially do not want to be compulsorily constrained). The challenge for us is how to continue delivering these customer priorities against a radically changing energy landscape, not least significant demand and generation growth as customers decarbonise.

Common to meeting these different priorities is the need to efficiently provide the capacity our customers need in the timescales they need it. We will do this to accommodate customer demand and generation growth, deliver a Just Transition to Net Zero, and ensure the continued safe, reliable, and efficient operation of the distribution network and wider system.

A changing energy landscape

Our distribution network was largely developed in the 1960s' to deliver electricity from big transmission-connected fossil fuel power stations to our customers. The network was configured into four main voltage levels for this, and was sized to accommodate industrial, commercial, and typical domestic demand. Just one in ten homes were electrically heated, and there were no EVs beyond the occasional milk float.

This model has incrementally evolved over many years to meet changing customer needs. We have rolled out monitoring and control across the higher voltage networks, although the LV network remains largely unmonitored. We have materially improved network reliability through better asset management. And we have delivered new technologies, such as active network management, to offer quicker and lower cost connections and accommodate renewable generation growth.

In short, the story of the last 60 years is one of customers' needs evolving steadily and incrementally. Our existing network capacity, planning tools, operational systems, and internal processes are tailored to these customer needs.

This slow evolution is now over. The energy landscape is changing fast as the way our customers generate, use, and interact with energy evolves. Three key trends are driving this:

- Decarbonisation – in response to the climate emergency, we need to achieve Net Zero greenhouse gas emissions by 2045 in Scotland and 2050 in England and Wales. To deliver this decarbonisation, we need to electrify a significant proportion of transport and building heating. We also need to complete the transition of our generation mix from fossil fuel to zero carbon generation by 2035[9]. These changes will significantly increase the levels of demand and generation that we need to connect to the distribution network for our customers.

- Decentralisation – the volume of generation which is smaller-scale and connected to the distribution network rather than the transmission network is increasing. This decentralisation has two effects: we must find ways to accommodate more customer generation than the distribution network is currently designed for; and as traditional transmission-connected generators close, the electricity system operator (ESO) has an increasing reliance on this DG and other controllable customer assets connected to the distribution network (collectively known as distribution energy resources, DER) to maintain GB system stability.
- Democratisation & digitalisation – means the rise of the active domestic customers (aka prosumer). Smart meters, home energy management systems, intelligent domestic and electric vehicle (EV) storage, specialist aggregators and suppliers – these are all reducing the barriers for domestic customer participation in the energy system. Democratisation has two effects: domestic customer consumption profiles are becoming less predictable and more dynamic; and we can increasingly work with many individual customers and communities, rather than just large DG or industrial customers, to source vital network and system services.

Forecasting and modelling the changes

To better quantify these drivers and ensure we meet our customers' changing electricity needs, we forecast what their electricity requirements are going to be into the future. We do this by developing DFES forecasts[10], and then comparing these against Net Zero compliant scenarios from the ESO[11] and the Climate Change Committee (CCC)[12] to identify the range of Net Zero compliant investment scenarios.

All Net Zero compliant scenarios show a significant increase in the volume of customer demand and generation that we will need to serve on our distribution network. This is primarily due to the electrification of transport (more EVs), the electrification of heat (more heat pumps), and more renewable generation (DG). Table 1 shows these values for the low, baseline, and high investment scenarios.

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[9] https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035

[10] Our "Distribution Future Energy Scenarios", republished with our RIIO-ED2 final submission Business Plan, are included as RIIO-ED2 Business Plan Annex 4A.6. Available at: https://www.spenergynetworks.co.uk/pages/distribution_future_energy_scenarios.aspx

[11] The Electricity System Operator's "2021 Future Energy Scenarios", published July 2021. Available at: https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

[12] The Climate Change Committee's "Sixth Carbon Budget", published December 2020. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget/

Table 1: Our RIIO-ED2 low, baseline and high scenario

Investment Scenario	Total SP Energy Networks uptake by 2028		
	EVs	Heat pumps	Additional DG
High scenario	1.03m	0.81m	+6.37GW
Baseline scenario	0.67m	0.37m	+4.95GW
Low scenario	0.65m	0.34m	+4.95GW

The magnitude of these changes is significant and unprecedented – customer needs have never changed at this scale or rate before.

We model the impact of these scenarios on our network using enhanced forecasting and modelling tools. We combine our investment scenarios, enhanced forecasting tools which predict EV and heat pump uptake for every customer we serve, our Engineering Net Zero (ENZ) Model (a full network analytical model including all 48,000km of LV), flexibility tenders for every single forecast constraint (1,557 sites), and an optimisation engine which impartially analyses and sequences all viable technical and non-technical solutions (including flexibility and energy efficiency) to create bespoke intervention plans for every constraint.

This approach systematically identifies where, when, and how we need to intervene. We're not building a plan on statistical estimates – we're addressing individual known constraints using market tested solutions. This data-driven approach means we build efficient targeted intervention plans – this keeps costs efficient for our customers and ensures they get the capacity they need to decarbonise. This is a step change in how investment plans are developed, which sets the standard for others to follow.

Responding to the challenge

Our forecasting and modelling showed that customer-led changes out to 2050 are far beyond what the network, our operational systems, and our internal processes are designed for. This creates four core areas we must deliver:

Create additional network **capacity**	Manage increasing **complexity**	Respond to increasing network **criticality**	Manage deteriorating asset **condition**
so we can accommodate our customers' EVs, heat pumps, and generation.	to safeguard the distribution network and whole system, and to enable new markets and services to operate safely and efficiently.	as our customers become increasingly dependent on their electricity supply for all their activities.	as utilisation and criticality increase due to greater levels of demand and generation.

We will respond by delivering:

- **Capacity**, through a combination of flexibility services, smart solutions, and network reinforcement. We will tender for flexibility services for all viable constraints.
- **DSO capabilities**, to expand our toolbox of solutions to support flexibility markets, analyse and share data, enable transparency and competition, and help manage a more complex and interactive system (see below).
- **Asset management interventions**, to manage the risk, reliability, resilience, and safety of our network. We will reduce the frequency of customer power cuts by 19% and their duration by 19%, and protect our customers served by rising and lateral mains.
- **Environmental interventions,** to reduce the environmental impact of our network and to increase its resilience to climate change.
- **Continued innovation,** to help deliver a safer, more reliable, and more cost-efficient Net Zero system (see below).

DSO

Simply providing more capacity by itself is not sufficient to address the complex range of challenges we face. We also need to adapt to more dynamic and volatile power flows, more energy system participants, greater interactivity across the whole energy system, and the need for greater coordination with the ESO.

We have developed a comprehensive DSO Strategy in response. It includes new infrastructure, such as an integrated simulation and modelling platform for our entire network (including all 48,000km of LV) so that we can make real-time data-driven planning and operation decisions, and LV monitoring at 14,102 secondary substations to increase network visibility and extend coverage from 14% to 76% of customers. It includes new DSO outputs, such as sharing outage information with gas companies and providing near-time dispatch and “no need” notifications to flexibility providers to increase whole system efficiency.

Our strategy will give us more network visibility, greater data analysis and sharing capabilities, enhanced forecasting and analytical tools, improved planning and operational coordination (not just with the ESO but also other network companies and vectors), new infrastructure to manage an increasingly complex array of network interventions, and greater use of flexibility (supported by increased data sharing, digital platforms, and transparency). It gives us the tools and capabilities we need to enable the customer-led revolution of the energy system.

Delivering DSO involves big changes for us. We will have to deliver a new system architecture, new ways of working, and new interactions with customers and stakeholders. Given the extent of these changes, and the importance to Net Zero, system stability, and our customers of getting it right, it is essential that our organisation is correctly structured to deliver DSO. For this reason, we have prepared a new DSO functional business model. It will be responsible and accountable for delivering DSO, whilst providing enhanced transparency to our stakeholders on our approach to designing and operating the network that we need.

We are best placed to lead the delivery of DSO. We have the capability, knowledge, and experience to deliver on time and in a cost-effective way. We have strong links with our customers and communities, which means we can quickly understand and respond to their needs. Most importantly, retaining a link between DNO and DSO means there is clear responsibility for the safety of network assets that enter into our customers' homes. We have our customers' interests at the heart of our decisions, as we seek to deliver an essential service that is safe, reliable, and resilient.

2.1.2. Innovation

It is clear that change is necessary to ensure a cleaner and more sustainable energy future and safely operate the more complex, dynamic, and interactive energy system. We are developing and delivering new innovative technologies that accommodates these changes, improves the way our network operates, and brings benefits to our customers. We have carried out extensive work to understand the impact of new forms of electricity generation and changes to the electricity usage on our networks. We are working with our stakeholders to understand what will happen as more people move towards LCTs. A sample of our innovation projects include:

Innovation in network forecasting

We have delivered a suite of innovation projects covering forecasting (EV-Up, Heat-Up, and Charge) and modelling (NCEWS and Network Analysis and View, NAVI). These projects help us better predict customer LCT uptake, and more accurately assess the network impact of that uptake.

This means we can better target the right interventions at the right time. This results in more efficient expenditure, facilitates the use of flexibility services, and reduces delays for customers waiting for capacity. Consequently, we used these tools to develop our RIIO-ED2 Business Plan and will continue to use them throughout RIIO-ED2.

Innovation in fault level monitoring and active management

We partnered with Outram Research Ltd to develop the world's first real-time fault level monitor. For the first time for any DNO, this gives an accurate real-time understanding of network fault level. We combined this innovation with a network management scheme – another first. These innovations allow us to safely connect more generation without triggering fault level reinforcements.

This is good for our generation customers, who can connect quicker and at lower cost. It's also beneficial for our wider customer base, who pay a portion of interventions to manage fault level.

Due to these advantages, we have included this system in our plans to manage 41 sites with higher fault levels and to facilitate lower cost generation connections.

Innovation in flexibility services

We have led the way in the development and use of flexibility services. We were the first DNO to tender for reactive power, and the first to offer site-specific pricing.

We successfully led GB's first trial to shift electricity demand to maximise local network capabilities and allow customers to capitalise on the opportunities from a transition to a smarter grid. Working with Octopus Energy, domestic customers were able to respond and shift when they used electricity to time slots when the supply of renewable energy was at its highest and help balance the demand of the network in their local community.

At 132kV in our SP Manweb network, we have combined flexibility services with a network automation scheme. One such scheme in the Carrington-Fiddlers Ferry group acts as a secure backup to flexibility – in the event that flexibility is needed and not available, the network automation secures the network by temporarily reconfiguring it. Such innovative arrangements have allowed us to defer significant investment, which financially benefits customers. We will embed this capability as business-as-usual in RIIO-ED2.

Innovation in active network management

Active network management is a key technology that DNOs use to connect increasing levels of distributed generation to networks which were previously considered to be at or approaching full capacity. These generators are connecting in accelerated timescales and for a fraction of the cost of reinforcement solutions.

We are in the process of deploying wide scale active network management across the Dumfries and Galloway network area in our SP Distribution network. This regulates the output of DG to avoid transmission constraints – this type of coordination across transmission and distribution is a UK first. The scale and nature of this project (one of the largest of its type) provides invaluable learning for further developing constraint management zones in RIIO-ED2 and extending their functionality to coordinate a wide variety of DSO functions.

In RIIO-ED2 we will deploy a new network control architecture – called Constrained Management Zones (CMZs) in 22 areas of the network. These will be at the heart of network operation in RIIO-ED2 and a key part of our DSO infrastructure. Please see our DSO Strategy for more information[13].

2.1.3. Green Recovery Investment

SP Energy Networks has been working with Ofgem and the Energy Networks Association (ENA) to unlock around £300m to support the transition to Net Zero and deliver a green economic recovery from Covid-19.

In 2021, we launched a call for evidence in order to identify green projects that we believe can benefit from quick deployment of network investment in the next two years. We are delighted to confirm that we were awarded more than £60m of funding through the Green Recovery investment programme to take forward these projects. These will provide additional electrical capacity to enable the connection of a host of LCTs such as EVs and heat pumps.

The call for evidence was designed to understand and validate the state of readiness of proposals and plans that developers, local authorities and other stakeholders are considering around the areas we have identified. This will enable us to create a priority order

[13] Available here: https://www.spenergynetworks.co.uk/userfiles/file/SPEN_ED2_DSO_Strategy_Report_July_2021.pdf

of network investment (reinforcement) and implement this in the past two years. It will also inform longer term network development in RIIO-ED2 and beyond.

Further details of the Green Recovery investment and funding are available online[14].

2.1.4. Losses

There are two categories of network losses:

1. **Technical losses** – these result from the laws of physics where they are an inherent result of power flowing through network assets. They can be managed but can never be eliminated.
2. **Non-technical losses** – these are units of energy transferred but not correctly accounted for due to errors in unmetered supplies, inaccurate billing estimations, and illegal abstraction.

Management of losses is complex because they are difficult to measure and influenced by factors outside of our control.

Losses in RIIO-ED1

At the start of the RIIO-ED1 regulatory period (2015 - 2023), Ofgem introduced a licence condition which requires DNOs to: “publish a strategy showing how we will ensure that Distribution Losses from our system are as low as reasonably practicable” and to “maintain and act in accordance with our Distribution Losses Strategy”

The test for “reasonably practicable” is an economic cost/benefit assessment. The SP Energy Networks RIIO-ED1 Losses Strategy was published in September 2015 setting out intentions for loss reduction, given what is reasonably practicable based on current knowledge and the ability to manage losses.

Cost effective loss reduction activities have a direct benefit to our customers in reducing their energy bills, and for the wider group of stakeholders, reducing wasted energy, reduces carbon pollution and slows climate change.

Since the start of RIIO-ED1, we have undertaken the following losses justified activities in both distribution areas. Specifically for SP Distribution:

- Replaced high loss transformers early, with estimated technical losses savings of over 14.3 GWh. The 2022/23 contribution to this is over 3.7 GWh.
- Conducted over 117,000 Revenue Inspections, identifying irregularity cases resulting in over 93 GWh of non-technical losses recovered. The 2022/23 contribution to this is almost 9.0 GWh.

[14] Available here: https://www.spenergynetworks.co.uk/pages/green_recovery_investment.aspx

- Completed over 510 Theft In Conveyance investigations, identifying interferences resulting in over 3.1 GWh of non-technical losses recovered. The 2022/23 contribution to this is over 0.6 GWh.

Losses Discretionary Reward

GB DNOs do not pay for the electricity lost on their networks. Therefore, in addition to the publication of a Losses Strategy, Ofgem requested that DNOs consider whether they are able to go beyond the licence requirement, incentivised through a Losses Discretionary Reward (LDR) mechanism. Its objectives were to progress the understanding of losses, improve processes to manage losses and identify new ones, and increase stakeholder collaboration, particularly in setting losses targets for RIIO-ED2.

We received an award or £770k in tranche one of the LDR in January 2016 for our work on an ambitious portfolio of initiatives. Although no rewards were given to any DNOs in either the second tranche (2018) or the third tranche (2020), it was noted that progress had been made in meeting these LDR objectives.

Throughout RIIO-ED1, we have worked with the other DNOs, Ofgem, our stakeholders and the wider industry to extend the boundaries of how we manage losses. This includes collectively improving our quantification and understanding of losses, improving detection of electricity theft, making effective use of Smart Meter data as it becomes available and working with our customers to reduce losses. The way our customers use our network will inherently impact losses, and losses are expected to increase significantly in the transition to Net Zero. Whilst we must not disincentivise the Net Zero transition with overly stringent losses targets, the LDR has highlighted new ways to incentivise losses savings and introduced exciting new opportunities for minimising losses in future business periods.

Losses in RIIO-ED2

Technical losses will increase in RIIO-ED2 with Net Zero decarbonisation. The electrification of heat and transport, greater levels of decentralised renewable generation, and increased DSO operation will increase distribution network utilisation, leading to an increase in losses. To manage this increase, in RIIO-ED2 we will consider all reasonable measures which can be applied to reduce losses and adopt those measures which benefit customers.

2.2. The Power Supply System

The Electricity Act 1989, as amended by the Utilities Act 2000, requires the holder of an Electricity Distribution Licence to develop and maintain an efficient, co-ordinated, and economical system of electricity distribution. The licensee is also required to facilitate competition in the generation and supply of electricity.

This LTDS provides for those interested in the development opportunities offered within the SP Distribution area, an overview of the factors that are relevant to the future development of the power system.

This section provides an overview and basic information on the technical aspects of distribution power system operation and planning.

2.2.1. Electricity System Operation and Balancing

The power supply system is planned and operated to provide secure and economic supplies of electricity to customers. Security and quality of supply is achieved through controlling and maintaining system voltage and frequency to within a satisfactory bandwidth around their nominal operating values.

Frequency

The frequency of the power system is determined by the balance of generation and demand at any one time. In the UK, the power system nominal frequency is 50 Hz. If generation exceeds demand, the system frequency will increase above nominal and if demand exceeds generation, the frequency will decrease below nominal. In general, system frequency continuously varies within the operational limits of 50.2 - 49.8 Hz, depending on the degree of mismatch between generator output and system demand. It is controlled by the ESO to within this operating range by means of manual and automatic interventions as required.

For contingency conditions, reserve generation must be available to cover the largest credible loss of generation or sudden increase in system demand.

Voltage

The voltage at any point on a power system is determined through a combination of:

- the voltage of generating plant connected in the surrounding area;
- the nature and parameters of the network through which the power is transferred;
- the level of power flow; and
- the electrical characteristics of customers demand in the area.

The voltage of the primary transmission system is controlled by varying the voltage ratio (tap changing) of generator transformers. This alters the excitation of generators, up to the limits of their operating characteristics. Voltage control at the interface between transmission and distribution systems is usually carried out by automatic on-load tap changing on the Grid Supply Point (GSP) transformers. Transformers at Primary distribution substations are similarly equipped with automatic on-load tap changing equipment, effectively controlling voltage on the HV distribution system. Control of the LV system voltage is facilitated via off-load tap changing equipment on Secondary distribution transformers whereby taps must be changed manually when required and only when the transformer is de-energised.

Transformer Automatic Voltage Control

Automatic voltage control schemes are designed to maintain the voltage of the 11 kV busbars at 33/11 kV substations, at or near to, their respective nominal values. The schemes employ on-load tap-changing transformers and use negative reactive compounding voltage control. Negative reactance compounding reduces circulating reactive power flows and tends to keep transformers operating in parallel at the same tap position.

Power Factor Correction

Reactive power increases losses and can affect voltage regulation and the operation of voltage control schemes. Negative reactance compounding is sensitive to power factor (the controlled voltage rises or falls as the power factor becomes more leading or lagging with respect to the power factor assumed to calculate the control relay settings). It is therefore advantageous to reduce reactive demand by suitable power factor compensation. This should be applied as close as possible to the specific load or embedded generation.

Voltage Regulations

In accordance with The Electricity Safety, Quality and Continuity Regulations 2002 (which replace the Electricity Supply Regulations 1988), the voltage supplied to customers must not, other than in exceptional circumstances, vary from the declared value by more than the values indicated in Table 2 below.

Table 2: Declared voltage ranges

Declared Voltage	Variation in Voltage from that Declared
LV	not exceeding 10 per cent above or 6 per cent below
HV	not exceeding 6 per cent above or below
33kV	not exceeding 6 per cent above or below

2.2.2. System Faults and Protection

The power system must be able to protect itself in instances where faults occur. Power system faults are broadly classified based on duration i.e. transient or permanent. Transient faults are the most common types of fault experienced e.g. a tree branch coming into contact with an overhead conductor. A fault is considered permanent if it cannot be cleared by the power system protection and manual intervention is required e.g. a cable is damaged during ground excavation.

Regardless of type, when a fault occurs on the power system, all generation equipment and rotating machines, i.e. generators and motors, contribute to the fault current. Fault current arising from the occurrence of a fault must be interrupted by the circuit breaker(s) controlling that circuit. Each circuit breaker required to clear the fault from the system must be capable of interrupting the maximum predicted fault current that is likely to flow at that point. In addition to this “break” duty, circuit breakers also have a “make” duty requirement which is the capability to energise a circuit which has been faulted or earthed. The maximum predicted fault current on any circuit or at any busbar can be calculated using this information. The method used by SP Distribution to calculate system short circuit fault levels is described in Section 2.4.4. Typical planning limits for fault currents on the SP Distribution system are outlined in Table 3. These values are the design limits for the respective voltage networks and any connection causing these design limits to be exceeded will require the provision of fault level mitigation measures.

Table 3: System fault level break limits

System Voltage	Three Phase Symmetrical Short Circuit Current		Single Phase Short Circuit Current	
	MVA	kA	MVA	kA
33kV	1000	17.5	1000	17.5
22kV	500	13.1	500	13.1
11kV	250	13.1	250	13.1
6.6kV	150	13.1	150	13.1

2.2.3. Power Quality

Voltage deviations occur on all power systems and can be a result of a number of incidents. The most common causes of voltage deviation are described below. The increasing sophistication, sensitivity, and dependence on computers and computerised process control equipment have greatly increased the impact of these voltage deviations on customers. Particularly affected are major process and service industry customers who are vulnerable to loss of production as a result of disturbances on the supply system which last less than a second. We have fault recorder devices located around the system that typically capture data on fault dates and times, fault duration and the severity of voltage depression. This information is used to ensure that high quality supplies are delivered to customers and enables us to assist customers in their understanding of their internal protection requirements and advise on methods of minimising exposure to these incidents.

While these incidents cannot be eradicated completely, our business strategy is to deliver continuous improvement in the Quality of Supply to customers.

Flicker

Voltage flicker refers to rapid variations in the voltage level on a distribution system, which may be caused by dynamically changing network loads, frequent switching operations and cyclic variations in embedded generator output currents.

Voltage Step Changes

Voltage step changes occur due to load and generation variations, the operation of tap changers and when the network is re-configured.

Voltage Dips

Voltage depressions, or dips, generally occur due to faults either on the customers own installation, other customer installations, or in the public distribution system due to insulation failure, 3rd party incidents or weather conditions. These are largely unpredictable and there are no specific statutory or licence requirements related to voltage dips.

Short / Long Term Interruptions

Short/long term interruptions are usually due to network faults and the associated auto-reclose or sequence switching that follows. Such interruptions are reasonably infrequent, occurring typically a few tens of times annually. Approximately 37% of the interruptions have a duration of less than 15 seconds for networks below 132kV and less than 60 seconds on networks of 132kV and higher. Occasionally, interruptions may last longer than a minute and it is difficult to give exact durations as they are usually weather related, or due to other external causes.

Spikes and Surges

Voltage transients or spikes on the supply system are excursions from the normal sine wave value. They mainly affect the LV system and are of very short duration. Typically, they vary from 100 V to 6,000 V and last less than a few milliseconds. Typical causes are the operation of fuses, capacitors, opening of contactors, switching of motors or household appliances. Such spikes are mainly produced by the customers' own installations and are rapidly attenuated, rarely penetrating through the distribution transformer.

Voltage Unbalance

Unbalance in a three phase supply is normally attributable to unbalanced loads and/or impedances. We minimise these unbalances by careful planning, design and construction of the distribution network. The major cause of imbalance is from the single phase loading of three phase rural overhead lines.

Harmonics

Any non-linear device drawing current from or injecting current into the power system will introduce a harmonic current component which will show as distortion of the voltage waveform. Typical sources of harmonic current are:

- Converter equipment, i.e. inverters, TVs, switched power supplies, wind turbine generators. These can all contain large inverters, ranging from 30-100% of their rating;
- Magnetic devices, i.e. transformers; and
- Non-linear loads, i.e. arc furnaces, DC electrolytic processes.

Power Quality Regulations

The Distribution Code for GB places obligations on customers regarding their impact on the system quality of supply. In addition, it requires their installations comply with the following industry standards:

- Engineering Recommendation G5/5: Planning levels for harmonic voltage distortion and the connection of non-linear equipment to transmission and distribution systems in the United Kingdom.
- Engineering Recommendation P28: Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom.
- Engineering Recommendation P29: Planning limits for voltage unbalance in the United Kingdom for 132kV and below.

Copies of the Engineering Recommendations and Technical Specifications specified in Annex 1 and Annex 2 of the Distribution Code, including those mentioned above, can be downloaded free of charge from the distribution code website[15].

2.2.4. Supply Information

Phase Relationships

Large electrical power systems are operated as three-phase systems where the voltage vector and angle are measured relative to a common reference.

The angular relationship between the voltage vectors of systems at different voltage levels is defined by the clock-face convention. The 400 kV, 275 kV and 132 kV systems are all in phase with each other. The red phase is the reference vector at transmission voltages and is considered to be at twelve o'clock.

In SP Distribution it is usually, but not always, the yellow phase which is taken as the reference vector for 33 kV and lower voltages.

All 33 kV systems are supplied from the higher voltage systems through star/delta (Yd1) transformers. The resultant phase shift places the 33 kV reference vector at one o'clock.

33/HV transformers are of vector group Dy11 with 132/HV transformers of vector group Yy0, which both result in the yellow phase vector on the HV busbar being at twelve o'clock with respect to the reference. Standard HV/0.433 kV distribution transformers will be of vector group Dy11, resulting in the yellow phase vector on the 0.433 kV busbar being at eleven o'clock with respect to the reference.

The traditional standard phase relationships are shown in Figure 2.

[15] Distribution Code Annex 1 and Annex 2 Documents: http://www.dcode.org.uk/annexes/

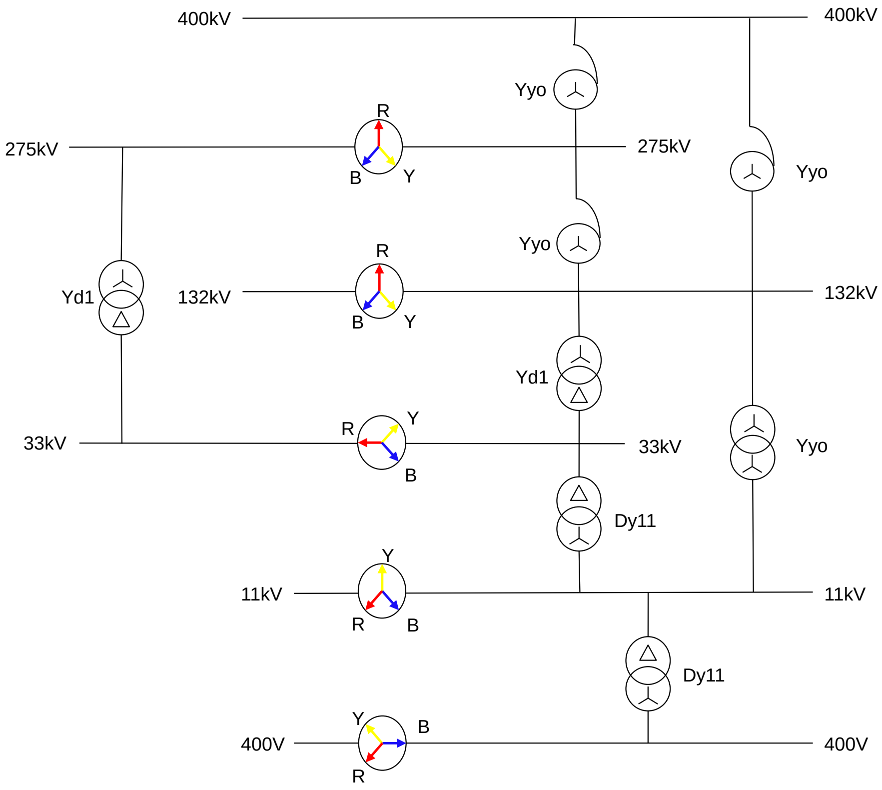

Figure 2: Standard system phase relationship

The vector grouping and phasing at each voltage level follow a standard relationship so that operational parallels can be made between different parts of the distribution network that operate at the same voltage.

Phase Colours

The UK is harmonised with the EU phase colour codes and all new installations must have the following phase colour codes applied (Figure 3 below).

	Earth (CPC)	Neutral	Line 1	Line 2	Line 3
OLD	**Green/Yellow**	**Black**	**Red**	**Yellow**	**Blue**
NEW	**Green/Yellow**	**Blue**	**Brown**	**Black**	**Grey**

Figure 3: EU phase colour codes

2.3. The Distribution System

The transmission system in Scotland operates at 400 kV, 275 kV and 132 kV to provide a secure supply of electricity to customers with large or special demands, and to Grid Supply Points (GSP), i.e. the exit points to the distribution system.

The distribution system is configured in a number of standard running arrangements and operates at 33 kV and 22 kV (EHV), 11 kV and 6.6 kV (HV) and 400 volts and 230 volts (LV), providing supply to the connection point of all remaining customers for industrial, commercial and domestic purposes.

Key statistics for the SP Distribution system are provided in Section 1.4 and schematic diagrams of the Primary distribution system are provided in Appendix 9: System Schematics (Table 9).

Authorised developments of the Primary distribution system to the end of the five-year period are outlined in Part 4: Development Proposals. Please note that Condition 39 of the Electricity Distribution Licence requires SP Distribution to restrict the use of certain information in connection with developments of a commercial or confidential nature which may distort competition. In order to comply with this obligation, this LTDS does not therefore include details or mention of any third party development until such times as the schemes are authorised by way of a Connection Agreement.

2.3.1. Distribution System Design Philosophy

The design of a distribution system requires careful consideration to balance cost with customer service. Over-design of a system can lead to poor utilisation and higher costs while under or ineffective design can result in reduced quality of service for customers, and in extreme cases, possible non-compliance with the Distribution Code and Electricity Distribution Licence.

The distribution system is therefore designed to be safe, reliable, economic and efficient whilst also considering environmental considerations and sustainable development. The design must seek to strike a balance between quality and security of supply to customers, environmental protection, social equity and economic development, subject to minimum standards of security set out in the Distribution Code.

The SP Distribution system operates with a high utilisation factor and low maintenance requirement, using standard equipment, voltages and phase relationships. Generally, only approved standard equipment, voltages and phase relationships will be accepted in the design of the SP Distribution system. The use of standard equipment has many benefits including a reduction in operating costs, through reduced equipment stocks and strategic spares, minimisation of training for operational staff on new equipment and improvements in system performance. Extensions and modifications to the distribution system must consider the existing system configuration such that design standards are maintained throughout. Any economic assessment of alternative designs is always based on whole-life costs and considers the financial incentives associated with losses and security of supply performance.

Distribution systems have evolved over an extended period of time and due to the relatively long life of power distribution assets, which can be greater than 40 years, many legacy practices continue to exist. These features have a bearing on present and future design practices. It is important to make best use of existing assets as well as to protect the reliability, integrity and performance of the system.

2.3.2. Design Principles and Standards

The SP Distribution 33 kV system is designed such that GSPs supply identifiable sections of the distribution network. The various distribution networks are operated radially throughout, utilising standard transformer and cable sizes.

The SP Distribution system is planned and operated to withstand the sudden loss or withdrawal from service of any Primary circuit without any loss of supply to customers or an unacceptable deviation in voltage or frequency. This assumes an intact system with no pre-existing circuit outages. The distribution outage maintenance programme is carefully planned and controlled to ensure that operational security standards are not infringed. Continuous outages are not normally permitted during the winter months of November to February.

The technical and design criteria and procedures applied in the planning and development of the distribution system are detailed within the Distribution Code of Licensed Distribution Network Operators of Great Britain. Under Condition 15 of the Electricity Distribution Licence Document, the SP Distribution system must also comply with the provisions of the GB Grid Code.

Security of Supply

A fundamental review of ENA Engineering Recommendation P2 has been undertaken by the Distribution Code Review Panel (DCRP) through the Energy Networks Association (ENA). This review has concluded with the that publishing of EREC P2 Issue 8 in February 2023.

The SP Distribution system has been designed in compliance with Engineering Recommendation P2 Issue 8 “Security of Supply”. Engineering Recommendation P2 Issue 8 describes the appropriate level of security required for distribution networks classified in ranges of group demand. This is the minimum standard applied for engineering security, although individual customers e.g. commercial or industrial, may desire a higher or lower “personalised package”. In general, compliance with P2 Issue 8 enforces duplicate supplies to Grid and Primary substations, and HV networks with a switched alternative arrangement.

Voltage Disturbance and Harmonic Distortion

To limit the effects of distortion of the system voltage waveform, the harmonic content of any load shall comply with the limits set out Engineering Recommendation G5/5 “Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Equipment to Transmission and Distribution Systems in the United Kingdom”.

The requirements of Engineering Recommendation P28 “Planning Limits for Voltage Fluctuations caused by Industrial, Commercial and Domestic Equipment in the United Kingdom” shall also be met. Voltage unbalance between phases shall comply with the levels specified in Engineering Recommendation P29 “Planning Limits for Voltage Unbalance in the United Kingdom”.

While there may be parts of the distribution system where harmonic levels are approaching the limits specified within Engineering Recommendation G5/5, we are not presently aware of any site where those limits may routinely be exceeded. We deploy power quality monitoring equipment to identify potential harmonics, flicker and voltage unbalance issues both as a commitment to customers connected to the network and as part of the connection process for new customers.

Detailed design policy on the various distribution networks is contained within the following sections.

Environmental Planning

We recognise that our installations, whether overhead or underground, can have an effect on the environment, and we seek to minimise this via careful planning and execution of projects.

Nevertheless, local interest in electricity distribution operations can in some cases lead to delays in obtaining the relevant planning and environmental consents. We therefore maintain a dialogue with regional government, local authority and government agency representatives to obtain their support. This approach enables those with responsibility for making decisions to have an improved understanding of the industry's needs. It also provides the opportunity to make them more aware of the schemes included in this LTDS.

Improving the confidence of regional partners is aided by us recognising the importance of conserving and enhancing environments potentially affected by future works, as set out in our Preservation of the Amenity Statement (in accordance with Schedule 9 of the Electricity Act). The approach is to carefully work within environmental limits and bring about improvements where opportunities arise. The same environmental standards are expected of developer partners.

2.3.3. Typical Distribution Networks and Configurations

The distribution networks in the SP Distribution licence area are spread across several voltage levels and across various geographical areas and population types i.e. urban and rural areas. There are typical configurations and topologies for each type of network e.g. urban EHV networks across the licence area will have a typical design, as will rural LV networks. The following sections describe these different network configurations, typical at each voltage level, for urban and rural areas. Typical protection, automation and control philosophies for each voltage level and network type are also detailed.

EHV Primary Distribution System

The Primary distribution system is a group of circuits that provides supplies to Primary substations and customers with an EHV point of supply. These circuits also offer the provision of emergency interconnection between GSPs. The circuits comprise sections of underground cable or overhead line (supported by steel towers or wood poles), or a combination of both. The EHV system operates at 33 kV and 22 kV.

Grid Supply Transformers

The EHV networks are supplied via SP Transmission owned 275/33 kV and 132/33 kV GSP transformers of standard size and vector group. All 33 kV networks are supplied from the higher voltage systems through star/ delta (typically Yd1) transformers.

The star point of each GSP transformer primary winding is solidly earthed. The 33 kV system neutral earth is provided by an auxiliary transformer (33/0.4 kV) and liquid earth resistor, connected close to the GSP transformer's secondary bushings.

GSP transformers are connected to the SP Distribution system via 33 kV circuit breakers owned by SP Transmission plc.

Automatic Voltage Control

Each grid supply transformer is equipped with an on-load tap changer and automatic voltage control (AVC) scheme. AVC equipment at GSPs is applied to each transformer such that the transformer secondary voltage is maintained within a pre-defined dead band of +/-2% of the nominal secondary voltage and ensures that the tap changers on each transformer remain in step.

Tele-control facilities allow real-time monitoring and control across the EHV networks and facilitate high quality system performance.

EHV Network Protection

It is SP Distribution policy to apply two levels of protection equipment, main and back-up, on all new EHV installations, ensuring that no single failure of a protection device shall result in a failure to clear a fault from the Primary system. The main protection, which initiates fault clearance, shall operate in less than 100 milli-seconds. On feeder circuits, the target for the maximum clearance time of the back-up protection that initiates fault clearance shall be 750 milli-seconds.

The protection applied on 33 kV feeders is in general unit type protection, although as a minimum, a 33 kV circuit breaker controlling a transformer feeder shall be equipped with three-phase instantaneous overcurrent elements and high speed earth fault protection. Back-up systems for each 33 kV feeder circuit breaker are provided using three-pole Inverse Definite Minimum Time (IDMT) overcurrent and single-pole earth fault protection.

Urban EHV Networks

The circuits in a 33 kV urban network consist mainly of standard sized underground cables that form transformer feeders or provide emergency interconnection between GSPs. Primary substations are connected radially to GSPs. The majority of GSPs have two-section busbar arrangements with each transformer feeder pair being connected to a different busbar section. The bus section circuit breaker is normally closed.

The 33 kV system configuration generally employed consists of two transformer feeders operating in parallel, controlled by two 33 kV circuit breakers. Alternatively, two pairs of transformer feeders may be banked onto two 33 kV circuit breakers where full use can be made of the circuit breaker rating. Other arrangements are possible if they fulfil the requirements detailed below:

- No distribution circuit shall have isolating facilities on more than 3 sites.

- Under normal operating conditions not more than five circuit breakers shall require to be opened to make dead any distribution circuit
- Not more than two transformers shall be banked on any circuit at one site.

EHV circuits that provide emergency interconnection between GSPs are operated with a normally open point. In certain cases, 33 kV interconnectors may be tee-ed to provide supply to a Primary substation. Circuits which can interconnect 33 kV busbars are protected by a unit type protection scheme. Back-up systems for each 33 kV controlling circuit breaker are again provided using three-pole IDMT overcurrent and single-pole IDMT earth fault protection.

Rural EHV Networks

The circuits on 33 kV rural networks are predominantly overhead lines of wood pole three-phase construction without earth conductor. While network configurations can be similar to those employed in urban areas, in cases where load conditions do not warrant a standard two transformer Primary substation arrangement, a single 33 kV transformer feeder may be employed.

All 33 kV (and 11 kV) overhead lines are constructed to SP Distribution specifications, which ensure that network reliability is maintained in weather conditions specific to the local geography. It is anticipated that following forthcoming legislation amendments, increased focus will be placed on improving rural overhead line network reliability during severe weather events.

Rural EHV Network Automation

It is SP Distribution policy that any single-transformer Primary substation has an automatic load transfer scheme fitted to its associated 11 kV network. As an alternative to this, single-shot auto-reclosing of the 33 kV circuit may be accompanied by automatic indication of any 11 kV incomers which have tripped on directional protection due to a backfed 33 kV line fault.

All new EHV circuit breakers controlling circuits of overhead line construction are fitted with auto-reclose equipment. Existing installations will be modified as part of planned replacement or modernisation. The auto-reclose equipment is applied on a per circuit basis and controls all circuit breakers within the zone of protection. The operating mode for all auto-reclose equipment is delayed single-shot auto-reclose. This enables many transient faults to be cleared automatically, thereby improving network performance.

The application of protection systems to EHV circuits in rural areas is similar to that in urban areas. If the protection scheme on existing transformer feeder circuits does not include inter-tripping from the Primary substation to the controlling 33 kV circuit breaker, a fault thrower isolator will be installed in the outdoor compound of the Primary substation.

HV Secondary Distribution System

The secondary distribution system is a group of circuits that provide supplies to Secondary substations and to customers with an HV point of supply. These circuits also offer the provision of interconnection, operated normally open, between Primary substations. HV circuits comprise sections of underground cable or overhead line, or a combination of both. While some small areas of the HV system in the centres of Glasgow and Edinburgh continue to operate at 6.6 kV, the bulk of the HV distribution system operates at 11 kV.

Primary Transformers

The HV network is supplied from the EHV network at Primary substations utilising transformers of standard size and phase connection (normally Dy11). Typically, twin 12/19/24 MVA (or 20/32 MVA) 33/11 kV Primary transformers feed a two section 11 kV busbar. Each incoming feeder is connected to a different busbar section. The incoming circuits operate in parallel with the bus section circuit breaker normally closed.

Due to past transformer specifications, a range of Primary transformer sizes continues to exist on the SP Distribution system. Transformers built to the original BEBS T3 specification have a normal (oil natural air natural) rating as detailed in the following table. Details of individual transformer parameters and impedances are given in Appendix 2: Transformer Data (Table 2).

Table 4: Standard primary transformers built to BEBS T3 specification

Nominal Ratio	Winding Configuration	Rating (MVA)
33kV/11kV	Dy11	5
33kV/11kV	Dy11	7.5
33kV/11kV	Dy11	10

Transformers constructed to later specifications have a normal rating as detailed in the following Table 5.

Table 5: Details of standard Primary transformers built to later specifications

Nominal Ratio	Winding Configuration	Rating (MVA)
33kV/11kV	Dy11	11.5 / 23
33kV/11kV	Dy11	12 / 24
33kV/11kV	Dy11	20 / 32

The continuous emergency capability of existing Primary transformers is dependent upon their original specification. Direct transformation from 132 kV to 11 kV also occurs in some cases.

The star point of each Primary transformer secondary winding is in general directly earthed, giving a directly earthed HV network.

Automatic Voltage Control

On-load tap changers are fitted to present day Primary transformers and are normally of the Standard Random Control type. This allows transformers operating in parallel to be out of step by not more than one tap step. The tap changing equipment is controlled by an Automatic Voltage Control (AVC) relay, which maintains the secondary voltage within limits of +/-2% of the set point voltage under all load conditions. The AVC equipment is normally set to a target 11.2 kV voltage at the Primary substation HV busbar.

Line Drop Compensation

Line drop compensation (LDC) is used where appropriate to compensate for HV network voltage drop under different load conditions. This equipment causes the tap changing equipment to increase transformer secondary voltage by an amount which can be varied, and which is in proportion to the transformer load. It is not usual to employ LDC equipment on an urban network. However, in rural networks LDC equipment is often essential.

Tele-control facilities installed in each of SP Distribution's Primary substations allow real-time monitoring of HV feeders and facilitate remote control of HV feeder circuit breakers.

Urban HV Networks

In urban areas, the HV network is almost exclusively constructed from standard size underground cables. The network is in general operated radially, such that Primary substations supply identifiable sections of HV network.

HV Network Configuration

HV switchboards at Primary substations usually comprise two sections of busbar with a central normally closed bus section circuit breaker. HV circuits are controlled by a ground mounted circuit breaker and typically form open rings from the two sections of busbar in a Primary substation or, form normally open interconnection between Primary substations. The typical protection arrangement on an urban 11 kV network is one adopting overcurrent and earth fault protection at the Primary substation source with ring main units at the Secondary substations.

HV ring circuits may be some kilometres in length with Secondary ground mounted substations being "looped-in" to the ring at various points along its length. HV cables terminate in the non-automatic ring switches of the connected ring main units. The "Tee-off" circuit of a ring main unit may be a fuse-switch or circuit breaker, used to connect and protect the Secondary substation transformer.

Rural HV Networks

HV rural networks are of predominantly overhead line construction and designed as a series of three-phase main lines with radial spur lines branched off. Ground mounted substations and/or cable network may occasionally be included to provide supply to specific customers or accommodate network changes requested by third parties. Similar to urban HV networks, rural networks are operated radially.

Overhead networks may form open rings but where demand is lower an alternative supply is not necessarily required. The disposition of demand may be such that a ring network is not geographically practicable, and most rural networks are radial with tee-off branches to customers.

All 11 kV (and 33 kV) overhead lines are constructed to SP Distribution specifications, which ensure that network reliability is maintained in weather conditions specific to the local geography. Following legislation amendments in 2006, there is an increased focus on improving rural overhead line network resilience during severe weather events to minimise the impact of severe storms on customers. Compliance with this legislation amendment will require network operators to actively manage vegetation to ensure that network security is not compromised by trees within falling distance of the conductors.

Rural HV Network Automation

On all new, replacement and refurbished overhead lines, the main lines are controlled via multi-shot auto-reclosing switchgear. This auto-reclosing switchgear is capable of a minimum of three trips to lock-out and may be ground mounted or pole mounted. It is SP Distribution policy to employ a reclose time of 10 seconds and reclaim time of 10 seconds. Protection settings are application specific.

Tee-off circuits have traditionally been protected by pole-mounted three-phase or single-phase expulsion fuses, but more recently by pole-mounted automatic sectionalisers. Automatic sectionalisers discriminate between a transient and persistent fault by counting the passage of fault current during the auto-reclose sequence of the controlling switchgear. Sectionalisers operate during the dead time of the auto-reclose sequence after a pre-determined number of passages of fault current. They are only fitted to circuits protected by a multi-shot auto-recloser with minimum number of trips to lock-out being one more than the sectionaliser count.

Many overhead line faults are transient in nature due, for example, to wind activity or lightning. The application of the above overhead line protection policy, introduced in 1993/94 improves system performance under transient fault conditions and limits the number of customers disconnected under persistent fault conditions.

HV Network Automation

Given that the HV network largely operates as a radial system with a switched alternative supply for emergency and maintenance purposes, a single fault will affect customer supplies and manual operation is generally required to restore the switched alternative. In order to improve system performance and reduce customer interruptions in both urban and rural areas, SP Distribution has established additional zones of protection on several strategic circuits, reducing the number of customers affected by any single fault to less than one thousand. Customer densities determine the mid-circuit position and the new switchgear includes a circuit breaker which operates for faults beyond the mid-circuit position. The program of installing mid-point protection has already started and a further enhancement to performance on these circuits includes installing secondary automation equipment. Two points on each strategic circuit are automated, the mid-point circuit breaker and normally open point.

LV Distribution System

Low voltage networks are supplied from the HV network at Secondary substations via transformers normally of Dy11 vector group. The neutral point of the secondary winding of each HV/LV transformer is solidly earthed. The Electricity Safety, Quality and Continuity Regulations 2002 require that the voltage at a customer's supply terminals be maintained within 230 V +10%, -6% i.e. within the range of 216 V to 253 V. Secondary distribution transformers have a standard no-load secondary voltage of 250V, and off load taps by which the secondary voltage may be varied by +/-2.5% and +/-5%. Fuses of an appropriate rating are installed on all LV feeders, providing protection against excess current whilst also ensuring discrimination with HV circuit and transformer protection schemes.

Standard connections are made to the LV circuits to provide supplies to small industrial, commercial and domestic premises and street furniture. These connections are made in a manner that provides a balanced electrical demand across the three phases.

The existing overhead and underground LV system has developed over a long period. The networks conform to a standard radial design, with circuits originating at a distribution fuseboard in a Secondary substation or pole mounted transformer, being branched and tapered to match load and voltage regulation requirements.

Urban LV Networks

The LV urban network is constructed of standard sized cables and typically supplied by utilising standard transformers as detailed in the following Table 6.

Table 6: Details of standard distribution transformers

Nominal Ratio	Rating (kVA)
11kV/LV	500
11kV/LV	1000

Early development of the LV urban networks employed 4-core separate neutral earth (SNE) systems, while in later years 3-core combined neutral earth (CNE) cables were used. New extensions of the LV system use 3-core waveform distributor cables and concentric service cables.

Rural LV Networks

Low voltage networks in rural areas can be of three-phase or single-phase overhead construction, typically supplied by an HV/LV pole mounted transformer selected from a range of standard ratings.

Extensive development of the HV overhead network combined with the facility to match customer demands to individual pole mounted transformer ratings has tended to limit the LV overhead network to distributing supplies to small groups of properties e.g. village areas.

SP Distribution policy states that bare wire LV overhead lines shall not be added to the system. New construction will be of Aerial Bundled Conductor (ABC) specification or underground cable.

2.3.4. Distribution System Trading Arrangements

Electricity demand varies from day to day and from hour to hour throughout the year, as illustrated by the 2022/2023 daily load curves shown in Section 2.3.6. In addition, generation and customer demand must be constantly matched. The diversity of generators and suppliers now established in the energy market requires that satisfactory trading arrangements be in place to facilitate the balance of generation and demand.

Trading Arrangements

In England & Wales, the New Electricity Trading Arrangements (NETA) were implemented on 27 March 2001. NETA takes a form similar to established commodity markets with forwards, futures, short-term bilateral and balancing markets.

The bulk energy market operates on the basis of bilateral contracts between generators and suppliers. Under the terms of our distribution licence, we are obliged to allow non-discriminatory access to all parties who wish to use the distribution system in order to facilitate their trades. The user will have connection and use of system agreements detailing their access rights and our responsibility is to deliver that service to the user. This enables each generator to meet their total contractual obligations from their portfolio of energy sources, and for each supplier to receive the energy from their contracted sources at contracted prices.

In the market environment, the responsibility for minimising the cost of energy production lies firmly with the generators.

The supply arrangements in our SP Distribution area entitle a supplier, wishing to supply premises in the SP Distribution area, to transfer the electricity required to meet the demands of their customers to the distribution system. The supplier may have their own generation or contract with another generator with appropriate generating capacity.

The rules governing competition in the electricity supply market are contained in the Balancing and Settlement Code (BSC). All licensees, including independent generators and electricity suppliers, are required to be a party to, and to comply with, the provisions of the BSC.

The BSC requires suppliers to use all reasonable endeavours to have in place adequate arrangements to obtain supplies of electricity to meet their requirements. Similarly, generators are required to use all reasonable endeavours to have in place adequate arrangements to supply their output.

Under the GB Grid Code, generators connected to the GB distribution network may be required to submit generation schedules to the ESO and may be subject to central dispatch. The ESO combines the generators' schedules and adjusts them as necessary to provide the users desired energy transport as well as the system services necessary for the safe and secure running of the power system.

In April 2005, Ofgem implemented British Electricity Trading and Transmission Arrangements (BETTA) by extending NETA into Scotland to establish a Great Britain market. Under this system, parties can enter into bilateral contracts or trade on forward or futures markets on a GB-wide basis. Further information on BETTA can be obtained from the Ofgem website, contact details for which are provided in Section 5.4 of this LTDS.

2.3.5. Embedded Generation

Embedded generating plant connected to our distribution network is diverse in type, capacity, operation, and source energies. We have embedded generation connected across all voltage levels, from large scale onshore wind generation to behind-the-meter domestic solar PV. There are many types of embedded generation, including Combined Heat and Power (CHP) plants, hydro, biomass, biogas, solar PV, wind, and geothermal power. Embedded generation can be stand alone or exist at sites that principally take demand but have significant on-site generation.

A list of embedded generating apparatus connected to the SP Distribution network is given in Appendix 5: Embedded Generation (Table 5).

Our DFES forecasts show that Net Zero will have a significant impact on the generation scenarios applicable for the future years of this LTDS. Although we are in discussions regarding a wide range of renewable generation sites, only those sites which have been secured by a Connection Agreement are considered in this LTDS. Customer commercial confidentiality prohibits third party discussion or release of information for sites that are still undergoing development. Therefore, for the purposes of this LTDS and until site details are otherwise in the public domain, the available renewable generation assumed may be conservative for the period covered by this LTDS.

Generation Connection Considerations

There are many considerations when connecting new generation to the distribution system. Major reinforcements for distribution systems are triggered when forecast power flows exceed the firm transfer capability in an area/network. Power flows are directly related to the magnitude and location of connected generation and demand. If new generation is located in an exporting area (where generation already exceeds demand), power flows will increase and reinforcements could be required. Where reinforcements are required, it can delay the connection of a generator, or reduce its export capability until reinforcements are complete. It is therefore desirable to consider the siting of new generation.

Other considerations such as fault levels, voltage regulation, and the possibility of introducing system instability are also taken into account in the design of a connection. We will consider any connection applications on an individual basis, within the requirements of its licence.

General guidance on the connection of embedded generation together with an indication of site-specific constraints can be found on the DG Connections Information website[16]. The Heat Maps tool described in Section 1.3 can also be used as a resource.

[16] Distributed Generation: www.spenergynetworks.com/pages/distributed_generation.asp

2.3.6. Distribution System Demand

Our network has to accommodate the peak demands that customers require from its networks. These peak demands often occur for a short period. The forecast trend is for system maximum demand to increase significantly out to 2050.

System Maximum Demand

The maximum system demand on the SP Distribution system for 2022/2023 was 3,250 MW and occurred in the half hour ending 17:00hrs on 14th December 2022.

Over the five-year period of this LTDS, the winter peak demand for the SP Distribution area is estimated to reach 3,767 MW by 2027/2028. The last five year's maximum demand is shown in Table 7 below. The predicted annual maximum demands for the SP Distribution system in the period covered by this LTDS are detailed in Table 8 below.

Table 7: Last five years' peak demands for SP Distribution

Historical System Maximum Demand (MW)				
2018/2019	2019/2020	2020/2021	2021/2022	2022/2023
3,437	3,384	3,132	3,203	3,250

Table 8: Predicted system maximum demand for SP Distribution

Predicted System Maximum Demand (MW)				
2023/2024	2024/2025	2025/2026	2026/2027	2027/2028
3,292	3,364	3,453	3,548	3,767

Looking forward, our DFES forecast a considerable increase in the medium to longer term driven by the electrification of customer heat and transport and increases in industrial and commercial load. These DFES forecasts are undertaken annually for key customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK and devolved government targets and other industry forecasts. Given the uncertainties out to 2050, we create forecasts for four main energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback – this is a key stage which helps ensure our forecasts reflect the plans and ambitions of the local communities we serve. These forecasts are disaggregated to a local substation level in tables Appendix 3: System Loads (Table 3).

When assessing the demand on the distribution system, due consideration must be given to the impact of embedded generation, CHP schemes, and flexibility services in offsetting demand, all of which will reduce the apparent maximum demand of the local GSP and consequently the distribution system as a whole. The predicted system maximum demand values detailed above reflect such circumstances.

Daily Demand Profile

The daily demand profile varies across the seasons as illustrated in Figure 4. Profiles are displayed for the day of the 2022/2023 Maximum Demand (winter) and the day of the 2022/2023 Minimum Demand (summer).

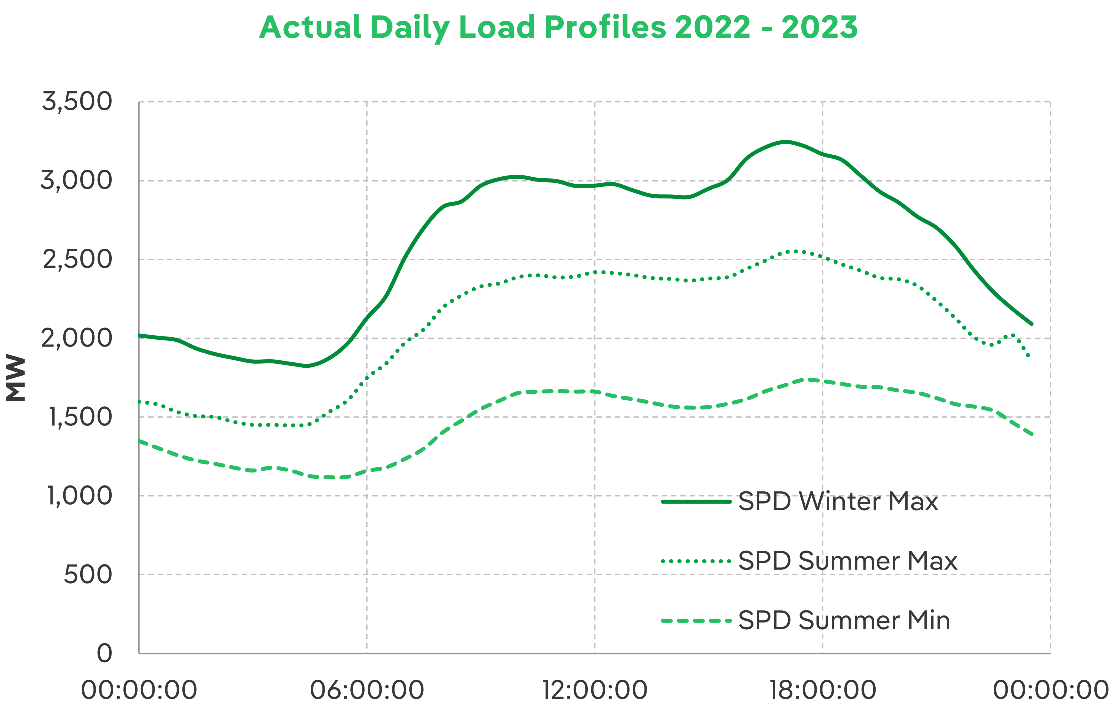

Figure 4: Daily demand profiles

Annual Demand Profile

In addition to demand varying throughout the day, it also varies with season. Superimposed on the unvarying demand of continuous process customers is a wide range of demand profiles of the various customer groups. This results in a profile of area demand that is lowest during mid-summer and gradually increases through autumn to the winter peak. After the system peak, demand reduces gradually as temperatures and daylight hours increase during late winter, into spring and early summer.

The demand profile (based on system HH demand readings) for the past twelve months (1 April 2022 to 31 March 2023) is shown in Figure 5. When carrying out analytical studies to establish load flows, fault levels and system stability, typical load values are utilised to reflect typical system running conditions for winter, spring/autumn and summer. These values have been established at 100%, 80% and 60% of system maximum demand (SMD) respectively.

When considering the annual demand profile, the daily variations of demand can obscure the longer-term profile. Therefore, in the interests of clarity, the background data for the annual demand profile shown have been filtered to improve the legibility of the long-term profile.

The relationship between System Minimum Demand and System Maximum Demand provides a generic system scaling factor which can be used to carry out high-level system studies for light load conditions. For the year 2022/2023, the system minimum load scaling factor for the SP Distribution system is 34%.

However, it is important to recognise that the scaling factors for individual substations will vary dependant on the particular load or customer types connected to that substation. Therefore, while the system scaling factor is representative of the system as a whole, at a local, or substation level, the minimum demands may vary significantly from values derived by the application of the system scaling factor.

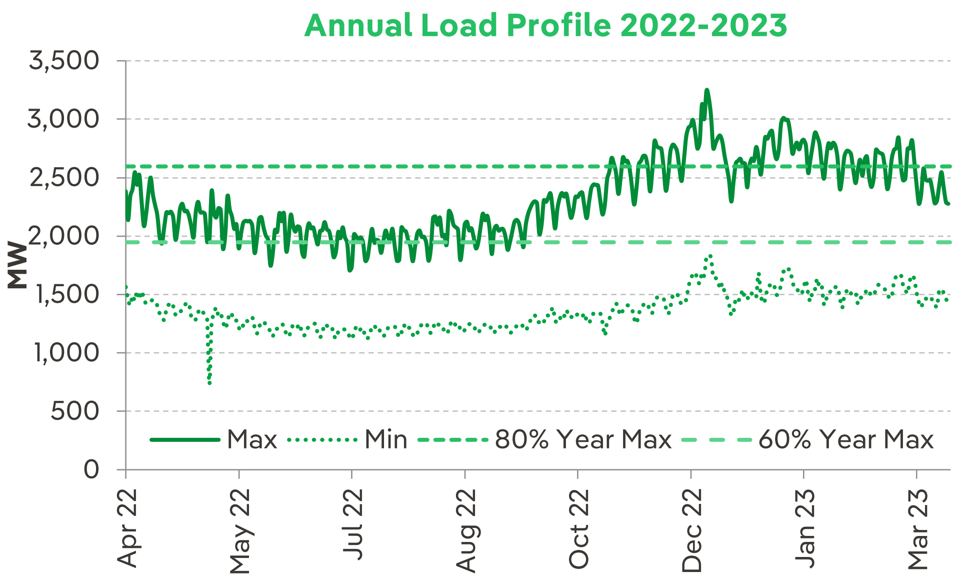

Figure 5: Annual load profile

Load Duration Curve

The system maximum demand will typically occur on a single occasion within the year. The system demand throughout the year is analysed to identify the proportion of the year that each increment of the system demand range occurs. The relationship between the percentage of the year against the proportion of system maximum demand is known as the Load Duration Curve and the Load Duration Curve for 2022/2023 is shown in Figure 6.

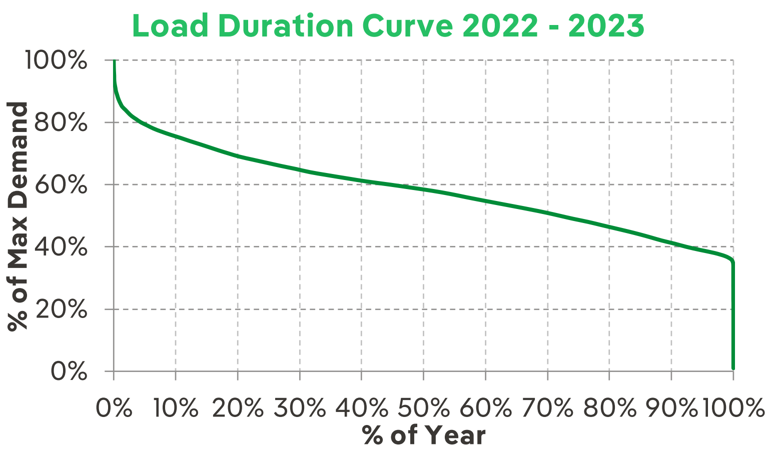

Figure 6: Load duration curve

2.4. Distribution System Performance

As stated earlier, the Electricity Distribution Licence requires SP Distribution to publish specific information regarding the capacity and prospective utilisation of its distribution system. The following sections explain the basis on which this information is provided and the associated tables and figures offer further detail.

2.4.1. Circuit Ratings and Parameters

The continuous thermal rating of a circuit is the maximum power flow that can be passed through the circuit on a continuous basis. This limit is the power that can be transferred without damaging the circuit components and without infringing statutory height clearances on overhead lines (due to thermal expansion and conductor sag), where these, form all, or part, of the circuit. There may be instances where switchgear or protection system characteristics cause a rating limitation. The thermal rating varies for each season of the year, because of the impact of differing climatic conditions on equipment performance.

Appendix 1: Circuit Data (Table 1) details circuit ratings, circuit resistance, reactance and susceptance.

2.4.2. Transformer Loadings and Parameters

The firm capacity of a substation is calculated as the maximum load it can serve under N-1 contingency conditions. Primary substations typically have two EHV/HV transformers to meet N-1 design requirements and as such the firm capacity is usually equivalent to the rating of one transformer. In cases where it is a single-transformer Primary substation, the firm capacity is equal to the rating of that single transformer. The maximum forecast loading on the SP Distribution Primary substation transformers is shown in Appendix 3: System Loads (Table 3). Most GSPs and Primary substations have surplus capacity enabling connection of additional load however where demand exceeds the firm capacity, remedial action may be required to ensure continued compliance with design requirements.

Where the actual maximum demand at a GSP or Primary substation is significantly different to the forecast demand, this may be the result of load being transferred between GSPs for temporary operational conditions and should be confirmed.

Appendix 2: Transformer Data (Table 2) lists transformer impedances and tapping ranges.

2.4.3. Substation Fault Levels

The prospective three-phase fault current for each distribution busbar has been calculated and these values, together with the corresponding X/R ratios, for the year 2022/2023 are detailed in Appendix 4: Fault Levels (Table 4).

The fault levels are calculated under the most onerous network conditions to yield the maximum anticipated fault currents. The most onerous network condition is considered to be when the following conditions occur concurrently:

- All generating apparatus is in service;
- All transformers are set to nominal tap position;
- The system is intact (N); and
- Fault level contributions are included from all independent generators.

The fault levels detailed in Appendix 4: Fault Levels (Table 4) are the Peak Make and RMS Break values with the most onerous conditions assumed. The peak asymmetrical circuit breaker breaking current (Peak Break) can be calculated using the empirical formula quoted in Engineering Recommendation G74. For this purpose, the appropriate system X and R values are also provided in the appendix table.

The actual circuit breaker breaking duty will be less onerous due to the decay of the AC and DC components within the operating time of the protection. Individual circuit breaker duty is further reduced by the value of the fault level contribution from the associated circuits (minimum fault in-feed).

Maximum fault levels must be constrained such that no individual item of switchgear on the system shall be exposed to fault interruption duties greater than its assigned rating. SP Distribution endeavour to construct and develop the distribution system to ensure that, under the normal operating condition the fault level will not exceed the equipment rating.

In established networks, where the calculated fault level is greater than 95% of the equipment design rating, or the network design limit (whichever is lower), a plan is formulated to rectify the issue. The high fault level will be resolved by,

- Replacing equipment that has a fault level rating lower than network design limit,
- Adding additional impedance to circuits,
- Replacing low impedance transformers with higher impedance units,
- Replacing standard two winding transformers for units with two low voltage windings, or
- Establishing entirely new substations.

Planning and implementing a fault level mitigation scheme takes time to complete. In circumstances where the calculated fault level exceeds the equipment design rating, or the network design limit, operational restrictions and interim measures shall be implemented to ensure the safety of staff and the public.

These measures may include,

- Access restrictions to substations,
- Installation of protective screening to create a shield around the equipment,
- De-energisation of equipment to temporarily lower the fault level,
- Auto-switching,
- Circuit re-configuration, and
- Replacement of three-phase termination equipment

The analytical models used for this LTDS have been constructed with the anticipated points of system separation. Actual running arrangements will always contain the fault level within the plant rating.

In the event that the assumed fault in-feed from a load (calculated in accordance with G74) is added to the system derived fault in-feed and this results in a site fault level approaching or exceeding the plant rating, operational procedures may be required to moderate the switchgear duty for that site.

From the data provided within the tables in Appendix 4: Fault Levels (Table 4), the actual fault levels at the SP Distribution Primary substations vary considerably. However, in general terms, fault levels on the SP Distribution system can be considered to have design limits for each voltage level. These design limit values are the maximum fault currents anticipated to be encountered in an intact system with normal running arrangements, where circuit outages due to planned or fault outages will increase the system impedance and hence reduce the fault level. The design limit fault levels for 33 kV and 11 kV are summarised below in Table 9 below.

Table 9: System design maximum fault levels

System Voltage	Three Phase Symmetrical Short Circuit Current		Single Phase Short Circuit Current	
	MVA	kA	MVA	kA
33kV	1000	17.5	1000	17.5
11kV	250	13.1	250	13.1

There may be some sites whereby system conditions and operating regimes result in the fault level being higher than the design limit values specified above; in these exceptional circumstances, the equipment specification would take account of actual site conditions. This will also apply to generation sites, where the fault in-feed from the generators added to that of the system may result in the fault levels at the lower voltage being greater than the design limit values. Again, the equipment specification for these sites would take account of the actual site conditions. In general, the fault levels at the higher voltage of these sites will be within the design limits.

2.4.4. Calculation of Fault Levels

Short circuit currents consist of a DC component with a fast decay rate and an AC component, which has a slower decay rate, relative to the DC component as illustrated in Figure 7 and Figure 8 below.

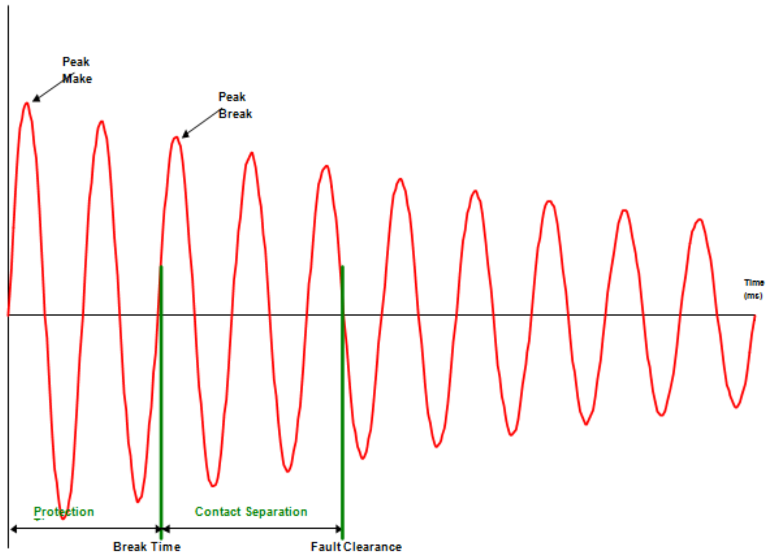

Figure 7: AC component of short circuit curent

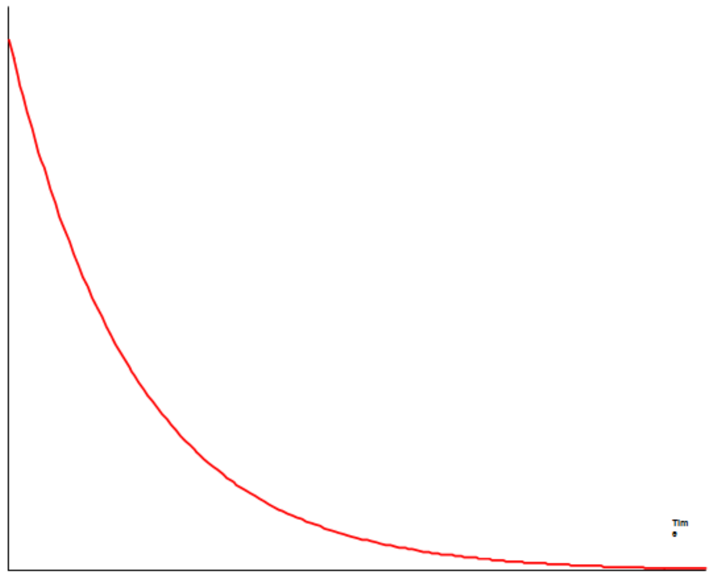

Figure 8: DC component of short circuit current

The magnitude of the DC component depends on the point on the waveform at which the fault occurs. The decay rate of the DC component is exponential, with the rate of decay dependent on the X/R ratio, which represents the ratio of reactance to resistance in the fault current path(s). The magnitude of the fault current contribution from rotating plant to the symmetrical RMS current will also be dependent on the time elapsed from the incidence of the fault.

Circuit breakers are required to have the capability of "making" fault current i.e. closing onto an existing fault and "breaking" fault current i.e. opening and so disconnecting a fault from the system. These duties are defined in terms of Peak Make, RMS Break and Peak Break:

- **Peak Make:** the maximum possible instantaneous value of the prospective short circuit current and occurs at the first AC peak after fault inception. Due to the time elapsed; there is little decay of the DC component.
- **RMS Break:** the RMS value of the AC component of the short circuit current at the time the circuit breaker is required to operate and takes no account of the DC component. This is effectively the nominal rating of the equipment.
- **Peak Break:** the largest instantaneous short circuit current that the circuit breaker may be required to interrupt, taking account of protection operating time. The Peak Break value is an instantaneous value and includes the DC component of the fault current.

Engineering Recommendation G74

An international standard for the manual calculation of system short circuit currents was issued in 1988 as IEC 909 "Short-circuit current calculation in three-phase AC systems". Application of this methodology gave rise to "conservative" results that could possibly lead to over-investment. As a result, a working group developed outline procedures for computer-based methods of calculating short-circuit currents, which could be used as an alternative to the methods presented in IEC 909. The procedure was subsequently issued in 1992 as Engineering Recommendation G74 "Procedure to meet the requirements of IEC 909 for the calculation of short-circuit currents in three-phase AC power systems".

Fault calculations contained within this LTDS have been calculated in accordance with Engineering Recommendation G74. The stated prospective fault current values within the data tables are the Peak Make and RMS Break values with assumed incremental fault in-feeds from rotating apparatus associated with site load, in accordance with the guidelines contained in G74. The Peak Break value will be less than the Peak Make value due to the AC and DC decrement in the protection and breaker operating time. Peak Break values are not included in this LTDS due to the site-specific nature and variability of components and settings.

2.5. Distribution System Capability

To achieve one of the Licence objectives of facilitating competition in the supply of electricity, the distribution system must be capable throughout the year of transferring large power flows between the system entry and system exit points. The transfer capability of the SP Distribution system (i.e. its ability to handle power flows to and from internal and external sources) is discussed in the following sections.

The secure transfer capability of the SP Distribution system between any two points can broadly be defined as the maximum load that can be transmitted without a breach of the design criteria (see Section 5.1: Technical References 1 and 6). These criteria, in general, require that no circuit overloads, unacceptable voltage or frequency excursions, or generation instability will be caused by the loss (or withdrawal from service) of any single EHV circuit.

Primary Substation Transformers

Most Primary substations have adequate capacity to accommodate existing and predicted loads. Load monitoring and forward projection permit the identification of locations that require an increase in transformer capacity.

Distribution System Modernisation

SP Distribution has an ongoing programme of system modernisation. When considering the modernisation needs of the distribution system, the opportunity is taken to rationalise the network configuration such that it satisfies the current needs of the power system and its users.

This document also includes details of system modernisation where there are changes to system configuration, apparatus capacity or fault interrupting capability.

2.6. Statutory & Licence Obligations

Under the Electricity Act 1989, as amended by the Utilities Act 2000, an electricity distribution licence holder has a duty to:

- Develop and maintain an efficient, co-ordinated and economical system of electricity distribution; and
- Facilitate competition in the supply and generation of electricity.

A summary of the licence conditions that SP Distribution plc must satisfy, which may be of interest to developers, follows:

i. To prepare and keep in force a Distribution Code which defines the planning and operating procedures which permit the equitable day-to-day management of the Distribution System.

ii. To plan and develop the distribution system in accordance with a Standard not less than that set out in Engineering Recommendation P2 Issue 8 (2023) of the Energy Networks Association Engineering Directorate.

iii. To prepare Statements of Charges for the connection to and use of the distribution system.

iv. If so requested, provide system information, in addition to that contained within this LTDS, indicating present and future circuit capacity, forecast power flows and loading on the distribution system.

v. To restrict the use of information submitted by potential users of the distribution system, which may distort competition.

vi. To comply with the provisions of the Balancing and Settlement Code (BSC).

2.6.1. The Distribution Code

The Distribution Code of Licensed Distribution Network Operators of Great Britain covers all material technical aspects of connections to, operation of and use of the distribution system.

Planning Code

The Planning Code section of the Distribution Code defines the distribution system standards and procedures to be used in the connection application process between a potential user of the system and SP Distribution. The document defines the planning criteria adopted by SP Distribution, the technical data requirements to be supplied by the user, and the mandatory response times for SP Distribution to make a contractual offer.

Connection Conditions

The Connection Conditions section of the Distribution Code specifies technical and operational criteria to be complied with by all users of the SP Distribution system and sets out the procedures by which SP Distribution shall ensure compliance by users with the above criteria.

2.6.2. Distribution Charging Statements

There are charges applied to any user for:

- Connection to the distribution system; and
- Use of the distribution system.

The charges for a user to connect to the SP Distribution system are defined in the document entitled "Statement of Basis of Charges for Connection to SP Distribution plc and SP Manweb plc's Electricity Distribution System". The annex to this document defines the difference between contestable and non-contestable work relating to a connection and the arrangements which apply where a user opts to appoint an approved contractor to carry out contestable work.

The charges paid by users authorised to supply or generate electricity and make use of the SP Distribution system are defined in the document entitled "SP Distribution Plc – Use of System Charging Statement.

These statements are prepared in accordance with Condition 13 and 14 of SP Distribution's Electricity Distribution Licence and detail the principles upon which charges for the use of, and connection to, the SP Distribution system will be based.

The charges are designed to provide a transparent pricing framework within which particular charges reflect and recover the costs necessarily incurred by SP Distribution in providing particular services. The Licence requires that the terms and charges contained in these statements be reviewed at least once each year.

Use of System charges relate to those parts of the distribution system which facilitate the bulk transfer of electricity between Entry Points (where electricity is collected from transmission or generators) and Exit Points or grid supply circuits (where electricity is delivered to individual premises).

Connection charges relate to assets which are dedicated to the provision of connections between the distribution system and either generators (Entry assets) or private networks (Exit assets).

These statements can be obtained from the SP Energy Networks website[17].

2.7. Advice for Developers

This document highlights many of the technical elements that need to be considered when connecting to the distribution network. The reference documents listed in Sections 5.1 and 5.3 will assist developers to assess the various technical and physical aspects of a connection. These cannot however provide the same benefits as discussion of specific requirements and connection arrangements with us at the earliest opportunity and this course of action is highly recommended.

The detailed system information provided as part of this LTDS is for general guidance and will prove of use to developers in identifying opportunities and assessing the relative merits of competing sites. However, as the existing and future distribution system is continuously evolving in response to operational requirements, system developments and customer applications, the data provided within this LTDS may be subject to revision. Such amendments may have an impact on the detailed planning of a site-specific development. Again, we therefore recommend that developers contact SP Energy Networks at an early stage when planning the development of a specific site. We will be pleased to discuss developers' plans, provide technical information and advice on connection, technical or financial issues. These discussions will be confidential until such times as the connection is finalised by the conclusion of a Connection Agreement.

Where additional system infrastructure is required to cater for large volumes of generation, a clear need case must be demonstrated. Potential generation developers are encouraged to contact SP Energy Networks at the earliest opportunity to register interest.

Customers, developers or installers wishing to install embedded generating units have a legal requirement to contact us prior to installation or commissioning (the only exception is one-off G98 generators i.e. up to and including 16 A per phase).

We require advanced notification for multiple applications of small units, or single installations of larger units, to assess their impact on the system and other users. Applicants will be advised of any works, costs and timescales due to their proposed installation. Details of the process are available on the SP Energy Networks website[18].

Applications for connection to the SP Distribution system should be addressed to Customer Connections, contact details for whom are included in Section 5.4.

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[17] Connections Use of System and Metering Services: https://www.spenergynetworks.co.uk/pages/connections_use_of_system_and_metering_services.aspx

[18] Connection Application Guide: http://www.spenergynetworks.co.uk/pages/distributed_generation.asp

2.7.1. Offer of Terms for Connection

The Electricity Distribution Licence conditions specify the timescale(s) within which SP Distribution must provide a formal “Offer of Terms for Connection” in response to a formal “Application for Connection from a Customer”. The Offer will specify any extension to the distribution network necessitated by the applicant's development. It will detail capital related payments, together with any specific conditions relating to that site.

2.7.2. Project Timescales

In general, the timescale of any distribution system modifications or additions is dependent on the extent of the work and the plant requirements of the project. SP Distribution will always endeavour to accommodate customer timescales and requirements within the constraints of system outages and equipment procurement. Discussions during the early planning phase will facilitate mutual agreement on project timescales that are achievable and meet the customer's requirements.

2.7.3. Interest in Connection to the SP Distribution System

Certain types of development often congregate in the same area, which means some areas of the distribution system are more prone to interest than others. Appendix 5: Embedded Generation (Table 5) and Appendix 6: Connection Activity (Table 6) detail the level of interest in connection in all areas of the SP Distribution system for both generation and demand developments.

3. Part 3: Detailed Information

This part of the Long Term Development Statement comprises the following sections:

- Circuit Data (Section 3.1)
- Transformer Data (Section 3.2)
- System Loads (Section 3.3)
- Fault Levels (Section 3.43.4)
- Embedded Generation (Section 3.5)
- Connection Activity (Section 3.6)
- Substation Abbreviation Codes (Section 3.7)
- Predicted Changes (Section 3.8)
- System Schematics (Section 3.9)
- Geographic Plans (Section 3.10)

A brief description of the information provided within each category is given in the following sections, while the detailed information tables for each of these sections can be found in separate Appendix documents.

3.1. Table 1: Circuit Data

The data included in this table is derived from power system analysis software and therefore the circuit parameters detailed in the following tables are based on the equipment between analytical node points. As some circuits may have intermediate node points, or a number of components, this aspect should be taken into consideration when assessing overall (end-to-end) circuit parameters. Those circuit sections labelled S/C, or short circuit, represent circuit-breakers, switches or busbar connections of effectively zero impedance.

The Circuit Data table can be found in Appendix 1: Circuit Data (Table 1).

3.2. Table 2: Transformer Data

This table provides the parameters for each group of transformers on the SP Distribution system.

The Transformer Data table can be found in Appendix 2: Transformer Data (Table 2).

3.3. Table 3: System Loads

Future levels of demand are based on the best estimate from information presently available. The minimum area demand on the SP Distribution system as a percentage of the system maximum demand value is detailed in Section 2.3.6. The annual system demand profile can be considered representative of the annual demand profile at the majority of Primary substations.

Generation is connected to a number of Primary substations and GSPs. This has the effect of supporting local demand and therefore the stated maximum demands for these locations may be less than the connected load, if these generators were operating at the time of the maximum demand. Similarly, significant generation in the form of CHP schemes can be embedded within customers' installations, which can have the effect of reducing the demand at their supply point and consequently the demand of the corresponding Primary substation or GSP.

The System Demand table can be found in Appendix 3: System Loads (Table 3).

3.4. Table 4: Fault Levels

This table provides plant fault levels for the distribution system as at the data freeze date. A small number of authorised proposals that will be completed after the data freeze date and that will potentially have a significant impact on fault levels has also been included to provide the most appropriate system data that is currently available. These can be found in Part 4: Development Proposals. For ease of reference, the table is displayed by voltage level. Voltage levels include 33 kV, 22 kV, 11 kV and 6.6 kV.

Short circuit currents are expressed in kA and have been calculated for three phase faults under maximum plant conditions. The tables provide details of the Peak Make and RMS Break duty. The three phase equipment rating (expressed in kA) refers to the RMS Break value. Switchgear ratings are also provided for each substation.

The fault level values provided in the appendix tables include a value for the assumed fault in-feed values from rotating apparatus associated with site load, in accordance with the guidelines contained in Engineering Recommendation G74. Although the load associated fault currents are included in the values, as an indication of the G74 magnitude, the G74 Peak Make component value is displayed. While in some cases apparatus capability may be in excess of the design limit, as described in Section 2.4.3, system fault levels will always be constrained within the relevant design limit. The tables indicate those locations where the predicted fault level is equal to or greater than 95% of the plant capability.

All lower voltage interconnection between Primary substations has been assumed to run normally open. Short circuit currents at customer locations are based on the assumed system configuration detailed in Appendix 9: System Schematics (Table 9).

The Fault Level table can be found in Appendix 4: Fault Levels (Table 4).

3.5. Table 5: Embedded Generation

Details of generation embedded within the distribution system are provided, together with an indication of the source GSP substation.

The Embedded Generation table can be found in Appendix 5: Embedded Generation (Table 5).

3.6. Table 6: Connection Activity

Details of connection applications and budget estimate offers made are provided, together with an indication of the source GSP substation.

The Connection Activity table can be found in Appendix 6: Connection Activity (Table 6).

3.7. Table 7: Substation Abbreviation Codes

In order to accurately identify equipment and locations for system analysis, network studies and network administration, a standardised method of plant referencing has been adopted.

Each substation is assigned a unique four-character abbreviation code which is derived from the site name. This then permits plant and circuits to be identified by referring them to substation codes. A unique node reference is obtained by appending two additional characters to the four-character substation code. The additional characters are generated to ensure that the node is uniquely identified and can comprise letters, alphabetic characters or a dash. By adopting this convention, all sites and equipment can be uniquely identified. Any circuit or item of equipment simply connects two node points. For example, the 33 kV circuit between Ayr GSP and Heathfield Primary is defined as AYR-31 / HEFIT1.

The Substation Abbreviation Codes can be found in Appendix 7: Substation Abbreviation Codes (Table 7).

3.8. Table 8: Predicted Changes

Appendix 8: Predicted Changes (Table 8) outlines the development opportunities for the SP Distribution network, highlighting connection opportunities for generation and load.

3.9. Table 9: System Schematics

Figures providing 33kV connectivity are provided in Appendix 9: System Schematics (Table 9).

3.10. Table 10: Geographic Plans

Geographic plans of the SP Distribution network area are provided in Appendix 10: Geographic Plans (Table 10).

3.11. Requests for Additional Information

The level of information provided within this LTDS is considered suitable to present users with an understanding of the overall system, together with sufficient detailed information to facilitate the assessment of user's developments. We welcome early engagement with developers to collaboratively develop their project and the subsequent connection works in a coordinated, economic and efficient manner.

In the event that additional information or clarification is required by users for finite areas of the network, contact should be made to the relevant points of contact as detailed in Section 5.4 of this document.

Where the data request requirements are relatively localised and readily accessible, the data will be provided as soon as reasonably practicable. Depending on resource requirements and availability, this could be achieved within a few working days. Where this will take longer, we will provide an estimate of the timescales for provision of the data.

However, where the data requirement request requires significant research or analysis, we will advise on the estimated cost of this work and seek agreement with the User prior to commencement.

4. Part 4: Development Proposals

This part of the Long Term Development Statement comprises two sections:

- Changes to the Distribution System
- Application & Connection Activity

4.1. Changes to the Distribution System

While all reasonable care has been taken in the preparation of this data, SP Distribution Plc is not responsible for any loss that may be attributed to the use of this information.

Brief descriptions of future AUTHORISED changes to the system are given in Appendix 8: Predicted Changes (Table 8). Major developments which will impact the configuration of the Distribution System are included. It should be noted that projects may be subject to significant amendment or cancellation.

As the distribution system is constantly undergoing change in response to system and customer requirements, it should also be noted that circuits, substations, or other equipment which are indicated as existing or planned within this LTDS, may be excluded from future LTDSs due to developments which are unforeseen at present, or be subject to significant amendment.

4.2. Application & Connection Activity

An indication of application and connection activity, for both generation and demand, is provided in Appendix 8: Predicted Changes (Table 8). The data is analysed by connection points to the network in terms of Grid Supply Points and (where applicable) Primary substations.

As previously described, there is a confidentiality obligation requiring us to respect client confidentiality such that the release of any information shall not distort competition. In order to meet this requirement, information relating to the connection of commercial developments will not be published until such times as these developments become authorised by the conclusion of a Connection Agreement. Therefore, any such developments are excluded from the tables provided.

5. Part 5: Additional Information

5.1. Technical References

1. **Distribution Code of Licensed Distribution Network Operators of Great Britain.** The Code covers technical parameters and considerations relating to the use of and connection to public distribution systems. Information about the distribution code can be obtained on the distribution code website[19]. Code Annex documents are free to download from the distribution code website.

2. **Electricity Act 1989.** This legislation sets out the regulatory framework and licensing regime for the UK Electricity Supply Industry.

3. **Electricity Safety, Quality and Continuity Regulation 2002.** The purpose of these regulations is to secure the safety of the public and ensure a proper and efficient supply of electrical energy. The Electricity Safety, Quality and Continuity Regulation 2002 supersede the Electricity Supply Regulations 1988. Copies of the regulations can be obtained from HMSO[20].

4. **GB Grid Code**. The Code covers all technical aspects relating to the planning, operation and use of the interconnected transmission system and the operation of electrical apparatus connected to that system. It is a requirement of the Electricity Distribution Licence that the SP Distribution system complies with the provisions of the GB Grid Code. This document is available on the National Grid website[21].

5. **Utilities Act 2000.** This legislation sets out a series of reforms for the system of regulation of the utility industries. The act established a single Gas and Electricity Markets Authority (the Authority) in place of the twin posts of Director-General of Electricity Supply and Director-General of Gas Supply.

6. **Engineering Recommendation (EREC) P2 Issue 8, "Security of Supply".** P2 Issue 8 sets out the minimum standard to be applied in the planning of the distribution system.

7. **Engineering Recommendation (EREC) G74,** "Procedure to Meet the Requirements of IEC 909 for the Calculation of Short-Circuit Currents in Three-Phase Power Systems". Issued by the Electricity Association in 1992. Supported by Electricity Association Engineering Technical Report No. 120, "Application Guide to Engineering Recommendation G74.

8. **Engineering Recommendation (EREC) G5 Issue 5**, "Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Equipment to Transmission and Distribution Systems in the United Kingdom".

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[19] Distribution Code website: www.dcode.org.uk

[20] HMSO: www.hmso.gov.uk/si/si2002/20022665.htm

[21] National Grid website: http://www.nationalgrideso.com/industry-information/codes/grid-code

9. **Engineering Recommendation (EREC) P28 Issue 2**, "Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution systems in the United Kingdom".
10. **Engineering Recommendation (EREC) P29**, "Planning Limits for Voltage Unbalance in the United Kingdom".
11. **Engineering Recommendation (EREC) G99 Issue 1**, "Requirements for the connection of generating equipment in parallel with public distribution networks on or after 27 April 2019".
12. *Reference intentionally left blank.*
13. **Engineering Recommendation (EREC) P16**, EHV or HV Supplies to Induction Furnaces (Supported by ACE Report No 48).
14. **Engineering Recommendation (EREC) P18**, Complexity of 132 kV circuits.
15. **Engineering Recommendation (EREC) G98 Issue 1**, "Requirements for the connection of Fully Type Tested Micro-generators (up to and including 16 A per phase) in parallel with public Low Voltage Distribution Networks on or after 27 April 2019".
16. **Engineering Recommendation (EREC) G78 Issue 4**, Recommendations for low voltage connections to mobile telephone base stations with antennae on high voltage structures.
17. **Engineering Recommendation (EREC) G81**, Framework for design and planning, materials specification and installation and record for Greenfield low voltage housing estate installations and associated, new, HV/LV distribution substations.
18. **Engineering Recommendation (EREC) G12 Issue 4**, Requirements for the application of protective multiple earthing to low voltage networks.
19. **Engineering Recommendation (EREC) P17**, Current Rating Guide for Distribution Cables.
20. **Engineering Recommendation (EREC) P24**, AC traction supplies to British Rail.
21. **Engineering Recommendation (EREC) P25 Issue 2**, The short-circuit characteristics of single-phase and three-phase low voltage distribution networks.
22. **Engineering Recommendation (EREC) P27**, Current Rating Guide for High Voltage Overhead Lines Operating in the UK Distribution System.
23. **Engineering Technical Report (ETR) 113** – ***withdrawn***
24. **Engineering Technical Report (ETR) 120**, Calculation of fault currents in three-phase AC power systems (Application Guide to Engineering Recommendation G74).
25. **Engineering Technical Report (ETR) 122**, Guide to the application of Engineering Recommendation G5/4 in the assessment of harmonic voltage distortion and connection of non-linear equipment to the electricity supply system in the U.K.
26. **Engineering Technical Report (ETR) 124**, Guidelines for Activity Managing Power Flows Associated with the Connection of a Single Distributed Generation Plant.

27. **Engineering Technical Report (ETR) 126**, Guidelines for Activity Managing Voltage Levels Associated with the Connection of a Single Distributed Generation Plant.
28. **Engineering Report (EREP) 130,** Application guide for assessing the capacity of networks containing distributed generation.

5.2. SP Distribution Documentation

29. **ESDD-02-012**: Framework for design and planning of low voltage housing developments, including underground networks and associated, new, HV/LV distribution substations. This document details the SP Distribution plc and SP Manweb plc requirements for the design of low voltage underground cable electricity networks including their new associated HV/LV distribution substations on greenfield housing developments.
30. **EPS-03-027**: Materials Specification Framework for Greenfield Low Voltage Housing Estate Underground Network Installations and Associated, new, HV/LV Distribution Substations. This document details materials requirements for Low Voltage underground cable electricity networks including new associated HV/LV distribution substations on greenfield housing developments.
31. **EPS-02-005**: Installation and Record Framework for Greenfield Low Voltage Housing Developments, Underground Networks and Associated, New, HV/LV Distribution Substations. This document details installation requirements for Low Voltage underground cable electricity networks including new associated HV/LV distribution substations on greenfield housing developments.
32. **EPS-03-031**: Materials Specification Framework for Industrial and Commercial Underground Connected Loads Up to and including 11 kV. This document details materials requirements for underground cable electricity networks up to and including 11 kV for connections to Industrial and Commercial Customers.
33. **EPS-02-006**: Installation and Record Framework for Industrial and Commercial Underground Connected Loads Up to and Including 11 kV. This document details installation requirements for underground cable electricity networks up to and including 11 kV for connections to Industrial and Commercial Customers.

Details on how to obtain copies of the Engineering Recommendations and Engineering Technical Reports is available from the ENA website[22]. Licence documentation is available from the Office of Gas and Electricity Markets (Ofgem) website[23].

SP Distribution documentation is available from the library section of the SP Energy Networks (SPEN) website[24].

[22] ENA website: http://www.energynetworks.org/
[23] Ofgem website: https://www.ofgem.gov.uk
[24] SP Energy Networks document library: https://www.spenergynetworks.co.uk/pages/documents.aspx

5.3. SPEN Relevant Documentation

Distribution Long Term Development Statement (SP Distribution)

This document is available free of charge via internet download (registration required) as described in Section 1.6.

Where additional information, or clarification, is required for finite areas of the network, contact should be made to the relevant points of contact detailed in Section 5.4.

SP Distribution LC14 Charging Statement – April 2023

This statement details the charges that SP Distribution apply and the justification for them. The statement is available free of charge via internet download[25].

Statement of Methodology and Charges for Connection to SP Distribution Plc and SP Manweb Plc's Electricity Distribution Systems

This statement details the basis for charging for the use of the distribution system and is available free of charge via internet download[26].

Distribution Code of Licensed Distribution Network Operators of Great Britain

The Distribution Code contains planning and operational procedures to permit the equitable day-to-day management of the SP Distribution system. This document is available from the Distribution Code website[27].

Electricity Ten Year Statement

The E-TYS provides details of the performance of the GB Transmission system for the previous year. This document is available free of charge via internet download from the National Grid website[28].

GB Grid Code

The Grid Code contains planning and operational procedures to permit the equitable day-to-day management of the GB Transmission system. This document is available free of charge via internet download from the National Grid website[29].

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[25] Statement of Charges for Use: http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp

[26] Statement of Charges for Use: http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp

[27] Distribution Code download: http://www.dcode.org.uk/

[28] ETYS download: https://www.nationalgrideso.com/insights/electricity-ten-year-statement-etys

[29] GB Grid Code download: https://www.nationalgrideso.com/codes/grid-code

5.4. Useful Contacts

Should any customer wish to discuss an existing connection or proposed development, they should contact the Network Connections team in the first instance. Dependent on the nature and size of the development, the enquiry will then be routed to the appropriate group.

Similarly, if a user requires some additional system data to facilitate their assessment of a development, they should also contact Network Connections team.

Network Connections (SP Distribution)	SP Energy Networks Network Connections 55 Fullarton Drive Cambuslang Glasgow G32 8FA ☎ 0845 270 0785

Dependent on the nature and size of the development, the enquiry will then be routed to the appropriate group.

Points of contact for documentation are as referenced throughout this LTDS.

SPEN CEO	Ms V. Kelsall Managing Director SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 0008
SPEN COO	Mr G. Jefferson Chief Operating Officer SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 0008
SP Distribution Director	Mr C. Arthur SP Distribution Director SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 0008
Network Planning and Regulation Director	Mr S. Mathieson Network Planning and Regulation SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G5 2AD ☎ 0141 614 0008

Commercial and Innovation Manager	Mr G. Boyd Commercial Group SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 0008
OFGEM (London)	Office of Gas and Electricity Markets 10 South Colonnade Canary Wharf London E14 4PU ☎ 020 7901 7000 https://www.ofgem.gov.uk/
Energy Networks Association	Energy Networks Association 4 More London Riverside London SE1 2AU ☎ 020 7706 5100 http://www.energynetworks.org/
Scottish and Southern Electricity Networks	Scottish and Southern Electricity Networks Inveralmond House 200 Dunkeld Road Perth PH1 3AQ ☎ 01738 455800 https://www.ssepd.co.uk/Home/
National Grid Electricity System Operator	National Grid ESO Faraday House Warwick Technology Park Gallows Hill Warwick CV34 6DA ☎ 019 2665 3000 https://www.nationalgrideso.com/