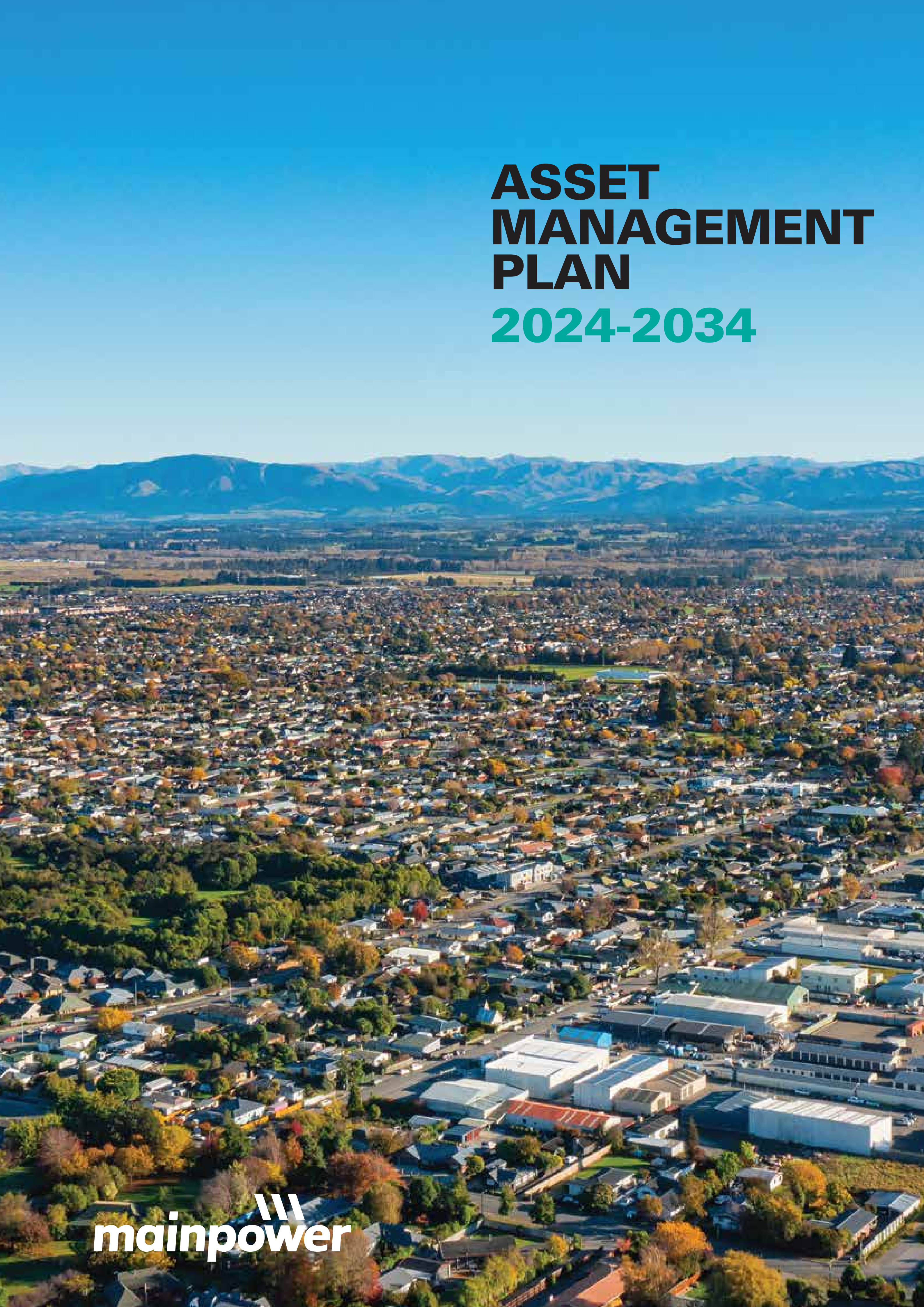
ASSET MANAGEMENT PLAN 2024-2034



mainpower

CHIEF EXECUTIVE'S MESSAGE

The needs and expectations of our customers are changing. New technology and innovations are opening up new ways of powering the homes and businesses of our region. MainPower sees huge potential ahead. Our vision is to create a smarter future to deliver local value.

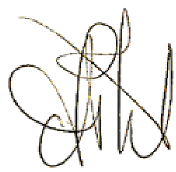
MainPower's Asset Management Plan outlines our commitment to providing a safe, secure, reliable and sustainable network that delivers electricity and energy services to homes and businesses in the North Canterbury region, from north of the Waimakariri River, through the Hurunui, to Kaikōura.

MainPower's vision is to create a smarter future to deliver local value. The energy industry is evolving rapidly, with new technologies and innovations impacting the way consumers generate, buy and sell energy. Community engagement sessions have reinforced that consumers want MainPower to facilitate their uptake of energy innovations by providing services and infrastructure that allows them to adopt new technologies when they are ready. In order to achieve this, MainPower is partnering with our customers to understand their uptake and needs so that we can meet their expectations.

As well as preparing our network for the changing needs of energy consumers, we're actively looking for ways to trial, test and report on our findings, including the feasibility of new innovations such as fleet electrification, distributed generation and smart technology.

This Asset Management Plan describes our network, our management practices and the assumptions that support our obligation as the responsible custodian of the MainPower electricity distribution network.

This plan details how MainPower will invest prudently in our electricity distribution network and related services for the next 10 years and how these services will enhance the delivery of safe, reliable and sustainable low-carbon energy – powering our communities while delivering value to the communities that, ultimately, own us.



Andy Lester
Chief Executive

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1. SUMMARY

MainPower New Zealand Limited (MainPower) is a consumer-trust-owned electricity distribution business (EDB) that builds, owns, operates and maintains the electricity distribution network in the North Canterbury region. MainPower provides electricity distribution services to more than 43,000 residential and business connections.

We are responsible for providing safe, secure, reliable and sustainable electricity distribution network and energy services to homes and businesses in the North Canterbury region, from north of the Waimakariri River, through the Hurunui, to Kaikōura.

We play a crucial role in supplying the energy needs of our communities, as well as contributing to the growth of a vibrant and prosperous region. The New Zealand electricity sector is facing significant transformation, driven by decarbonisation, decentralisation and digitisation (the "New Energy Future").

Owing to changes in the sector, our role is also changing. This requires a new approach and refreshed thinking about our strategic direction to ensure we continue to build and operate an electricity distribution network for the future that is responsive to consumer demand while delivering value to our consumers, the community and our shareholders.

Efforts over the last three years have focused on improving the stability of the business and identifying and addressing opportunities to make the business more efficient. A key outcome of this is the continued support of the core network business, ensuring network services will keep up with change within the sector while also delivering value to our consumers and shareholders.

MainPower has reviewed and developed its Network Transformation Roadmap to ensure the electricity distribution network services that MainPower provides change at a rate that matches changing consumer behaviours, considering the advent of new technologies and the national transition to a low-carbon economy. The review also required MainPower to develop key workstreams that support the future impacts of climate change, including adverse weather, sea level rise and wildfires. A key project supporting this is MainPower's Digital Twin, which enables MainPower to model the physical impacts of weather on network assets in a fully integrated environment.

In 2020, MainPower went live with our new advanced distribution management system (ADMS) for the smart operational management of the network. This system was further embedded into our daily operation in 2021. The ADMS is a key part of ensuring our network is ready to support the Network Transformation Roadmap.

We continue to assess our asset management systems, processes and practices against the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) and against ISO 55001 via independent evaluation. MainPower remains committed to ensuring our asset management maturity is aligned with our organisational goals and objectives, including compliance with ISO 55001.

Currently, our electricity distribution network performance (quality of supply) is unduly affected by planned works specified in MainPower's Asset Management Plan (AMP) work programme. The AMP continues to support workstreams that will return the quality of supply to past levels and improve it into the future.

2. ASSET MANAGEMENT PLAN

2.1 Our electricity distribution network

MainPower owns and operates North Canterbury's electricity distribution network, from the Waimakariri River in the south up to the Puhi Puhi Valley north of Kaikōura, and from the Canterbury coast inland to Lewis Pass (see Figure 2.1). We provide electricity distribution services to more than 43,000 North Canterbury homes and businesses.

Growth in the region, particularly with new subdivisions, has brought us nearly 3,000 new consumers during the past three years. We are committed to contributing to a bright future for our region by delivering an electricity distribution network that is ready for the future.

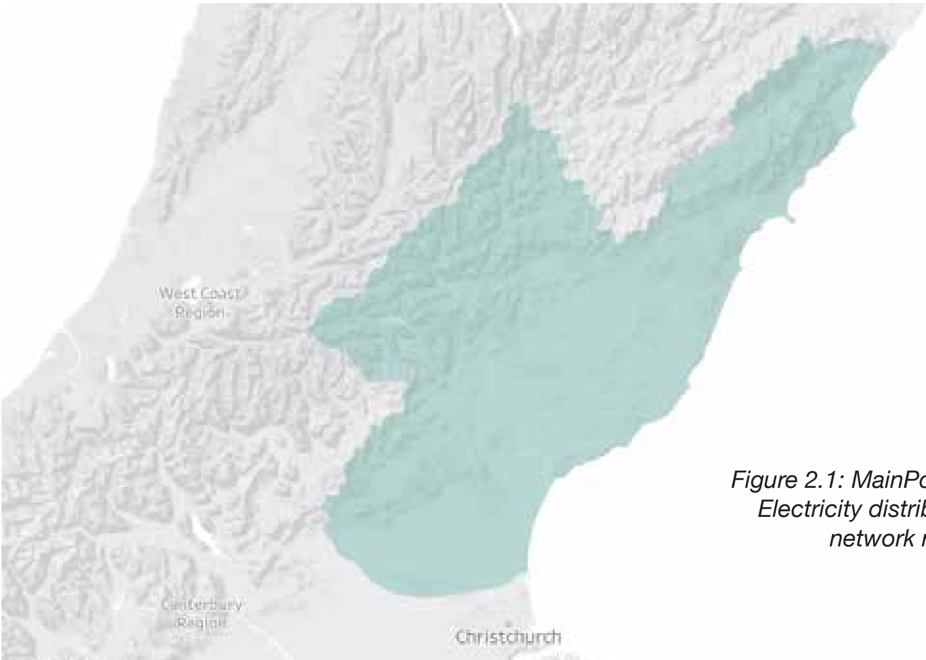


Figure 2.1: MainPower's Electricity distribution network region

We have lines and cables operating in three distinct voltage ranges:

1. Sub-transmission – 33 kV and 66 kV
2. Distribution – mostly 11 kV and 22 kV, but also 6.6 kV
3. Low voltage – 230 V single-phase or 400 V three-phase.

Our electricity distribution network connects to the New Zealand national grid at voltages of 66 kV, 33 kV and 11 kV via Transpower's transmission grid exit points (GXPs). The national transmission grid carries electricity from generators throughout New Zealand to electricity distribution networks and large, directly connected consumers (see Figure 2.). GXP assets are owned mostly by Transpower, although MainPower owns circuit-breaker protection and control equipment at some Transpower sites.

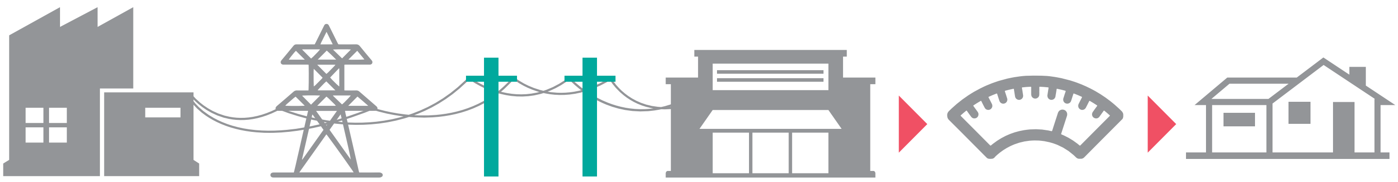


Figure 2.2: MainPower's position within the New Zealand electricity supply chain

2.2 Network transformation and evolution

The traditional production and use of "energy" is changing. Alternative affordable technologies, government policy, regulation and consumer behaviour have already created unpredictability in the energy sector. Examples include:

- the need to meet climate change objectives, which could be achieved by switching energy use to renewable electricity by 2050
- new consumer technology that is increasing the options for consumers to produce and store energy, thus impacting traditional energy use
- consumers choosing to adopt new technology and options that reflect their needs as they meet climate change objectives (e.g. considering alternatives to hydrocarbon fuel for transport and heating).

2.2.1 Framework

MainPower's Network Transformation Roadmap, which is based on the Electricity Networks Association Network Transformation Roadmap, is designed to provide an open platform, reliable connection and the efficient operation of the New Zealand electricity distribution industry for the long-term benefit of consumers. The roadmap contains a number workstreams to improve asset management maturity, designed to achieve an "Open Network Architecture" (see Figure 2.).

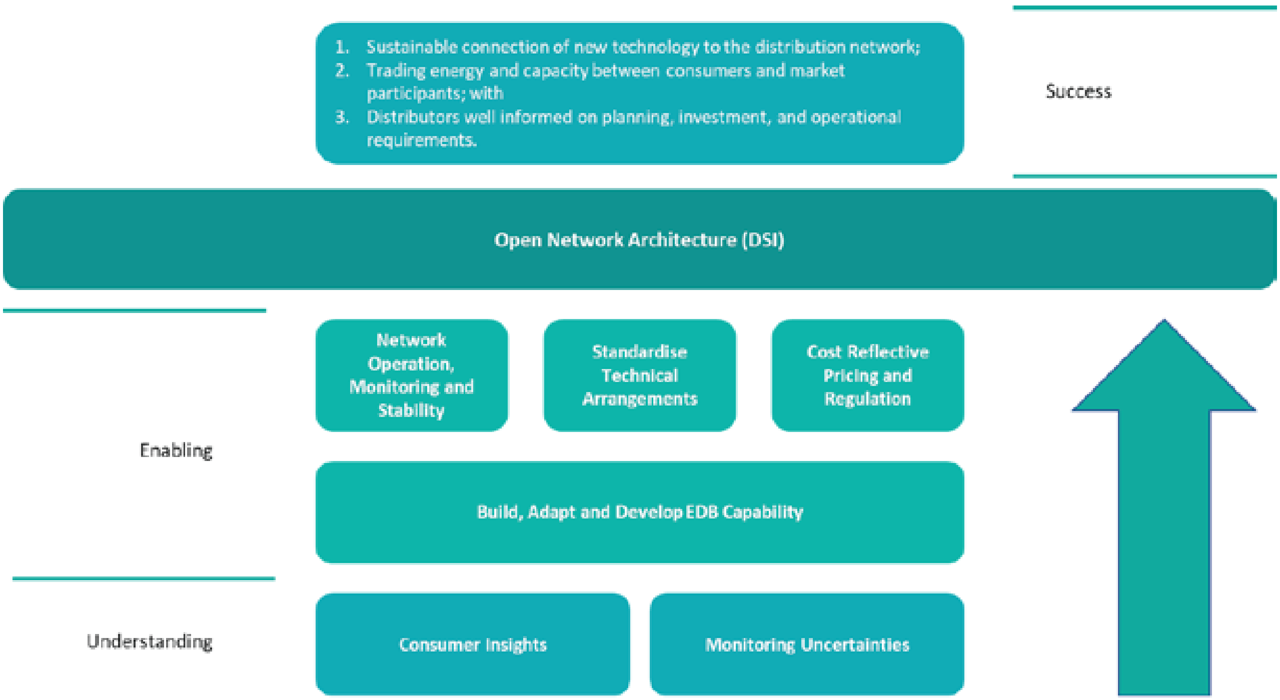


Figure 2.3: Open network architecture

2.2.2 Climate change impact

As the North Canterbury community seeks to reduce its carbon footprint, the community's electricity distribution network services will be a key enabler, providing a clean electricity energy source. The electricity distribution service is vital for the wellbeing of our community. This obliges MainPower to understand the impact of climate change on the community's network, to achieve safe, reliable and resilient network services.

Climate change means our community will be exposed to extreme weather events. It also means our consumers' consumption patterns will change because of changes in weather patterns impacting irrigation, heating and cooling, as well as the use of new technologies such as solar photovoltaics and electric vehicles (EVs). Based on the recommendations of the Task Force on Climate-related Financial Disclosures, MainPower now reports on the impact of climate change on our network assets for our consumers, including what we are doing about it, as outlined in Figure 2.4 and Figure 2.5.

2.2.2.1 Physical impacts

		Risk Assessment	50 year Change	Impact	Treatment	Commitments
Physical	Vegetation	High	Increasing	Impacting continuity of supply, Network Performance, Event Resourcing The number of events are expected increase	Use of Coordinated Incident Management response (CIMs) Delivery of Vegetation Management as part of the annual work programme Employ public notifications and awareness	Improved Asset Management using Lidar technology for clearance management including tree identification and growth rates
Physical	Severe Weather	High	Increasing	Damage to Overhead infrastructure from increased windspeed – beyond original design specification Damage to underground infrastructure from flooding	Review design criteria and designs standard Develop a digital twin model for the modelling of assets	Assess windspeed impacted to existing assets within digital twin model. Review replacement program based on assets impacted Partner with NIWA, Lifelines and Civil Defence for improved community sustainability modelling.
Physical	Wildfire	Medium	Increasing	Dryer conditions leading to increased exposure and severity of fire, causing damage to assets Exposure to 3rd Party fire damage leading to reputational damage	Maintain clearances through vegetation management and fall zone reporting. Employ public notifications and awareness Review of areas susceptible to wildfires and assessed assets affected including loss of supply impact	Continued resource availability to support the management of fire risk to Network Assets.
Physical	Sea Level Rise Tsunami	Low	Gradual	Impact to low lying areas of the Network, necessitating relocation of assets	Review of asset location when working in low lying and coastal areas	Review existing assets and their location as data around sea level rise changes Partner with Lifelines and Civil Defence enhancing community modelling

Figure 2.4: Physical impacts of climate change

2.2.2.2 *Behavioural impacts*

		Risk Assessment	50-year Change	Impact	Treatment	Commitments
Behavioural	New Technology	Low	Increasing	Increased demand on the network as consumers become more reliant on electricity Possible impacted to AMP forecasts and changes to work program as consumers become more reliant on electricity	Continued scenario based demand forecasting informing AMP expenditure programmes Continued consumer engagement and surveys to understand consumers future need for Network services	Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs).
Behavioural	Regulation	Low	Increasing	Possible market changes impacting the way the Network is used Carbon pricing affecting consumer Low Carbon Technology (LCT)decision making	Involvement in industry working groups to understand possible demand changes including the impact of change.	Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs).
Behavioural	Pricing	Low	Increasing	Pricing signals to consumers leading to consumption behaviour changes that negatively impacts reliable power supply	Continued implement of pricing Roadmap. Awareness to other market participants about the impact of pricing signals (Hour of Free Power)	Continued review and understanding of demand changes including engagement with other Electrical Distribution Boards (EDBs). Introduction of price signals that enhance market efficiency and value of consumer LCT choice

Figure 2.5: Behavioural impacts of climate change

2.2.2.3 *Analysis and management of impacts*

The National Institute of Water and Atmospheric Research (NIWA) climate projections describe greater variability in weather patterns, with more frequent and extreme weather events occurring as mean temperatures rise in the mid to long term. The upper South Island is expected to experience an increase in the number of hot days, a decrease in the number of cold nights, and an increase in temperature extremes on hot days. Extreme wind speeds are also predicted to increase throughout the South Island.

MainPower is developing a collaborative framework with external service providers to improve weather prediction and forecasting capability, and to overlay those predictions with network information to better manage the network in extreme situations and improve the resilience of the network. MainPower's ADMS real-time and historical information will be integrated with climate data to find network constraints in modelled scenarios. Additionally, ADMS data will be used to fine-tune resilience models for specific application in MainPower's region. With this data, MainPower will be able to proactively reinforce network areas that are potentially vulnerable to the impacts of climate change, and to improve network resilience to adverse weather-related events.

2.2.3 Enhanced asset management – condition-based risk management model

MainPower has identified the need to improve on its asset management investment decision making to enhance both price–quality trade-off and overall asset portfolio risk. In 2022, MainPower embarked on introducing condition-based risk management (CBRM) models for overhead assets and distribution switchgear, taking into consideration both the cost of overhead asset replacement and the impact of defective switchgear equipment on network performance (see Figure 2.6).

- Leverage existing data to create actionable information
- Embed expert knowledge within models
- Monetise risk to enable economic analysis
- Tailor modelling to the network and experience
- Model the effect of your planned programme of works
- Compare results across asset classes
- Align with industry best practice

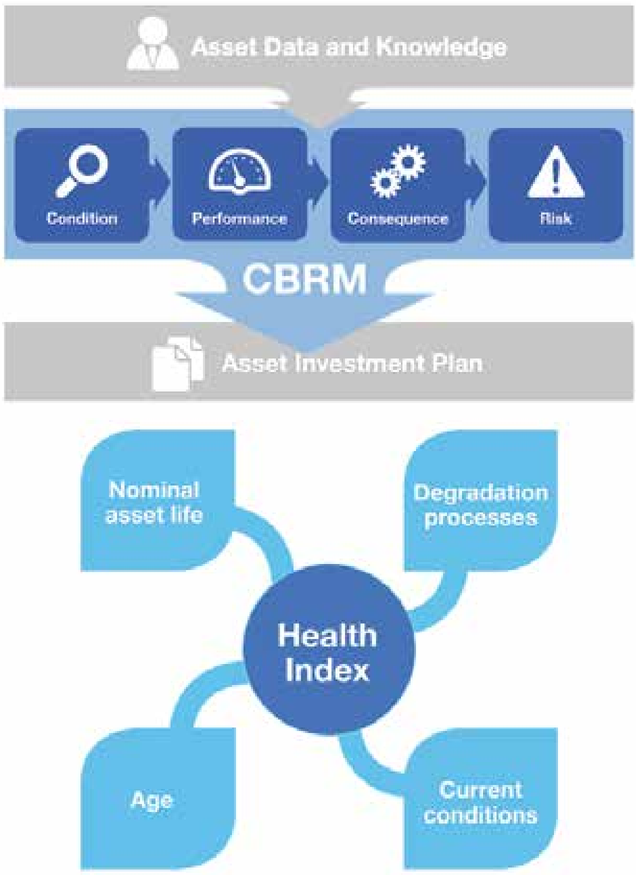


Figure 2.6: CBRM diagram

2.3 Asset management

This AMP covers a 10-year planning period, from 1 April 2024 to 31 March 2034. It provides our stakeholders with insights and explanations as to how we provide electricity distribution network and energy services in a safe, secure, reliable and sustainable manner that meets their expectations.

The AMP is a planning document that provides information on asset management systems, processes and practices, with a specific focus on development, maintenance and replacement plans for our electricity distribution network assets while also balancing cost, risk and electricity distribution network performance in accordance with our stakeholders' requirements.

The information within the AMP also informs our annual business and financial planning. This ensures sufficient resources are directed to deliver identified asset management needs, consistent with MainPower's overall corporate objectives. The AMP demonstrates our alignment with best-practice asset management processes. The content and structure serve to achieve the information disclosure requirements set out in the Electricity Distribution Information Disclosure Determination 2012.

2.3.1 MainPower's asset management objectives

As the community transitions to a low-carbon economy, the services the electricity distribution network provides will need to change. The services will need to enable widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. The services will also need to ensure open-access arrangements for consumers to allow them to transact over the network and connect any device they wish within acceptable safety and reliability limits. This means:

- the distribution network will rely on physical assets to convey electricity to consumers, as well as from consumer to consumer, or consumers to bulk supply points;
- consumers will be actively involved in the management of their energy acquisition, generation and consumption;
- the distribution network will provide network connections for multiple sources of distributed generation devices and other consumer-side devices;
- the distribution utility may not become involved in the transactions between consumers and other parties and may only be involved in balancing supply and demand on the network; and
- network stability will be managed by the EDB for a range of operating scenarios.

2.3.2 MainPower's asset management system purpose

The purpose of asset management at MainPower is to:
- specify the requirements for establishing, implementing, maintaining and improving MainPower's Asset Management System;
- cultivate a strategic asset management culture within MainPower;
- define the purpose and contents of key Asset Management System documentation under the Asset Management Framework;
- define the accountabilities and responsibilities for key documents and processes in the Asset Management System;
- describe the application of relevant external standards; and
- ensure the Asset Management System aligns with MainPower's requirements, other business management systems, company objectives and policies.

MPNZ BOARD-APPROVED POLICIES	RISK	ENVIRONMENT	ASSET MANAGEMENT
INTERNATIONALLY ACCEPTED STANDARDS	ISO 31000	ISO 14001	MPNZ BOARD-APPROVED POLICIES
	PROCESSES, PROCEDURES, WORK INSTRUCTIONS, GUIDES, INTERNAL STANDARDS		

Figure 2.7: Asset Management Standards

2.3.3 MainPower's Asset Management Policy

Our Asset Management Policy supports our corporate vision, values and strategic objectives. It provides a framework for asset management practices to consistently deliver safe, secure, and sustainable electrical distribution network services for current and future generations. The Asset Management Policy describes our commitment to asset management and our Asset Management Plan sets out how we implement this policy. We are committed to regular review of our processes and systems to ensure continual improvement. This Policy is supported by the Asset Management Implementation and Audit Guide that contains detailed deliverables of what is expected for each asset management element.

Underpinning everything we do are MainPower's values. They define who we are and what we strive to achieve through our operations. Figure 2.8 shows how our values impact day-to-day asset management operations.

- Ensure compliance with laws, regulation, standards, and industry codes of practice.
- Ensure consumer engagement and experience effectively informs asset management.
- Provide resources that ensure asset management objectives can be delivered.
- Contribute to a net-carbon zero energy future at lowest sustainable cost to consumers.
- Support environmental sustainability.

- Apply quality management systems and strive for continuous improvement and innovation.
- Apply industry best practice, systems, methodologies, and technologies.
- Apply performance monitoring and benchmarking against industry peers.
- Apply risk-based approach to managing our assets, balancing cost, performance, and risk.
- Ensure network growth delivers consumer requirements while facilitating sustainability.
- Understand and manage the physical and behavioural impacts of climate change on our network.

- Apply effective business systems and processes, roles, and responsibilities.
- Collaborate to drive strategic change within the industry delivering real value to our consumers and market efficiency through transparency.

- Manage competency and training.
- Optimise operational plans and activities and do it right first time.
- Deliver our Asset Management Plan

Figure 2.8: MainPower's asset management policy

2.3.4 MainPower's asset management system

The key elements of MainPower's asset management system are described in Figure 2.9 and Table 2.1 below.

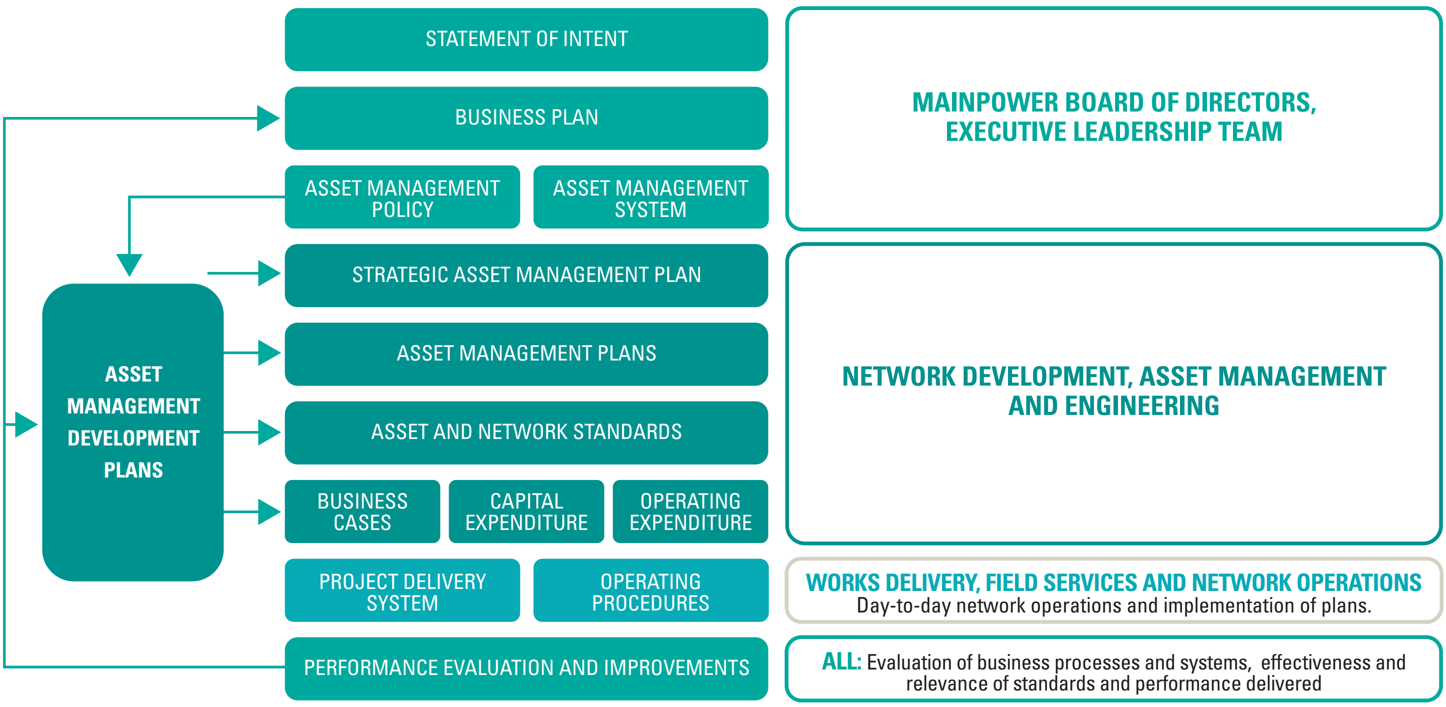


Figure 2.9: MainPower's asset management framework

System Components	DESCRIPTION
Statement of Corporate Intent	Presents the strategic direction and operational environment of the organisation.
Business Plan	Articulates the business goals and objectives that are aligned with the strategic intent of the organisation and how the business is going to achieve the goals.
Asset Management Policy	Defines the key principles, responsibilities and approach to asset management.
Asset Management System	System used to manage MainPower's assets.
Strategic Asset Management Plan	Optimises value by making appropriate trade-offs between risk, cost and performance.
Asset Management Plans	Detail MainPower's plan for managing its assets to deliver an agreed standard of service.
Standards	Documents that detail the quality or achievement of assets.
Business Cases	Used in project approval process to deliver works detailed in this document through a capital sanction process (this AMP document is not an authorised work programme).
Capital and Operating Plan and Expenditure Reports	Used throughout the year to monitor delivery costs against the original plan.
Project Delivery Systems	Used to govern and manage the delivery of projects.
Operating Procedures	Used to document the safe operation of plant and equipment.
Performance Evaluation	Reviews the performance of the asset management system, including service levels to consumers.

Table 2.1: MainPower's Asset Management System components

2.3.5 Asset lifecycle

MainPower has adopted a lifecycle asset management process structured on a total lifecycle cost of asset ownership. The framework has its foundation in the activities that occur over the lifetime of the physical asset (see Figure 2.10 and Figure 2.11).

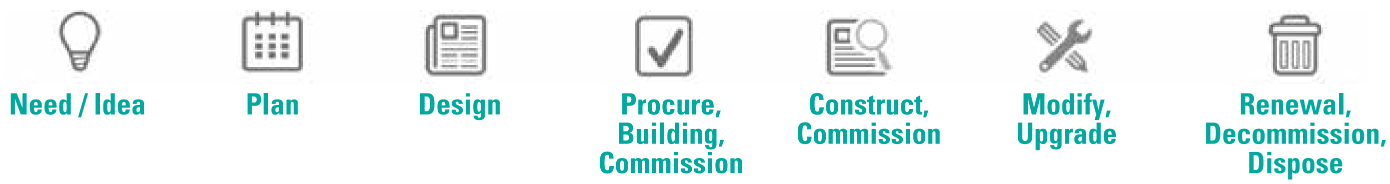


Figure 2.10: Asset lifecycle planning

The steps of the process are as follows:

- **Develop a need or idea:** The need or idea can come from anywhere within the business. It typically details a high-level view of the intent or requirement of a given project. Each idea is formulated by the project's sponsor, using a "sponsor's brief" document. Once the brief is written, a project is initiated and a project manager is assigned.
- **Plan a project:** The project plan sets out the specific requirements of the project. This includes a definition of the requirements, timelines, resourcing, procurement and risk. The project manager is responsible for the project plan and delivering the project against the plan. The project sponsor approves the plan and provides oversight throughout the project.
- **Design phase:** A completed design is a design that is informed by the requirements of the project, design criteria and standard design. We must complete the design; only then is the design fit for achieving the outcomes of the project. The asset manager must approve the asset before the design process introduces it. All assets on the MainPower electricity distribution network are approved by the asset manager.
- **Construct the asset:** The Service Delivery Team is responsible for project delivery, as detailed within the MainPower Project Delivery System. Later, the final step of "Practical Completion" can be issued only if the asset has a Fleet Management Plan, is entered into the computerised maintenance management system (CMMS) and has a maintenance schedule against the asset, and all asset data are reflected in our geographic information system (GIS).

- **Operate, maintain and monitor:** Asset criticality defines the level of maintenance. The treatment of the asset – in terms of maintenance activities (restoration or prevention) and/or critical spares – is defined in line with the criticality flowchart. Asset data, complete with template work orders entered into the CMMS and informed by rate cards, are used to develop annual resource planning (budgets, people, plant and equipment, and materials).
- **Modify and upgrade:** Assets are assessed against service levels. Sometimes this assessment highlights the need to modify or upgrade an asset. It is noted that assets can be upgraded due to changes in legislation, safe working procedures, etc. Instances also arise where existing assets are relocated based on changes of service levels.
- **Reneval, decommission or dispose:** Both an asset's condition (recorded in the Asset Health Indicator (AHI)) and its level of criticality inform the need for asset renewal, which is assessed against the cost and risk to the business.

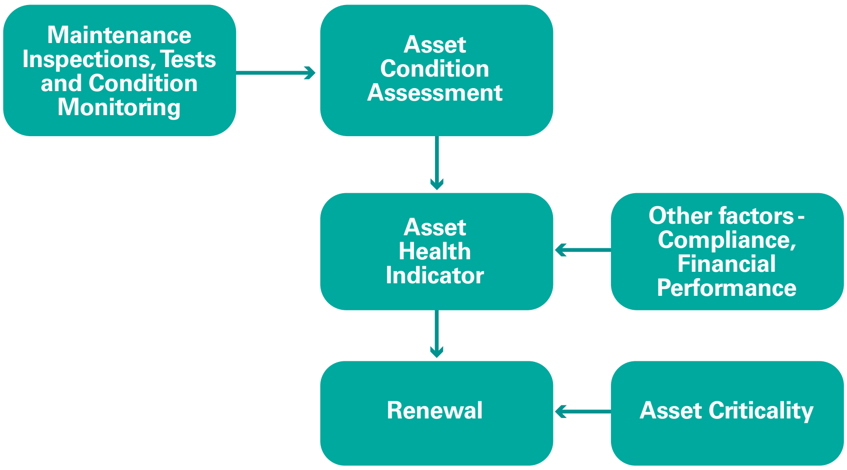


Figure 2.11: Maintenance process for asset renewal

2.4 Planning period

The AMP documents the likely development, maintenance and replacement requirements of the network and non-network assets over the next 10 years, from 1 April 2024 to 31 March 2034, with a focus on specific projects that have been identified for the next five years.

There is inherent uncertainty in AMP forecasts. Several factors contribute to this uncertainty, including pandemics and weather events. Our AMP forecasts are reasonably certain for five years. Except for potential large customer developments, including DG, our plan has some certainty for the remainder of the planning period.

2.5 Date approved by directors

This AMP was completed for asset management purposes in 2023 and was approved by the MainPower Board of Directors at their December 2023 meeting.

2.6 Stakeholder interests

Defining and understanding the needs and desires of our stakeholder groups allows us to structure our strategic objectives and define service levels in a way that is meaningful and relevant. Figure 2.12 shows our stakeholder groups.

CONNECTED CONSUMERS	COMMUNITY	OTHER STAKEHOLDERS	PARTNERS
Recipients of our services, including residential, small-to-medium businesses, large users, rural (farming) and individually managed consumers. Connected consumers are also preference shareholders.	People within the distribution area that are affected by our network, either in use or during installation and maintenance.	Customers with an interest in the operation of our organisation, including MainPower Trust, Government, regulators, district and regional councils, representative groups, contractors and suppliers, property developers and the media.	Participants in the electricity supply chain that help us meet our connected consumers' needs, including Transpower, electricity retailers, other distributors, electrical contractors and alternative technology providers.

Figure 2.12: MainPower's stakeholder groups

2.6.1 MainPower consumers and customers

Primarily, the link between MainPower's consumers and our customers is through our Use of System Agreement and Connection Agreement. Under Part 12A of the Electricity Industry Participation Code, the Use of System Agreement with our retailer customers is based on conveyance. MainPower's consumers are also our customers for the provision of lines services and this relationship is governed by our Connection Agreement. For the purpose of this AMP, MainPower also refers to our customers as "consumers".

2.6.2 Stakeholder engagement

We identify the expectations and requirements of our stakeholders through a wide range of engagement activities, including consultation, correspondence and online feedback via our website. Our other methods of identification are summarised in Table 2.2.

Stakeholder	How we identify the expectations and requirements of stakeholders
All stakeholders	• Consultation and correspondence
Connected consumers	• Consumer account managers • Consumer discussion groups • Consumer research (quantitative and qualitative methods) • Direct current feedback/interactions • Events (including the Annual Meeting) • Informal contact/discussions • Open days • Public meetings and information sessions • Submissions on discussion papers
Community, representative groups	• Direct current feedback/interactions • Forums and working groups • One-on-one meetings • Open days • Submissions on discussion papers
MainPower Trust (ordinary shareholders)	• Direct current feedback/interactions • Events (including the Annual Meeting) • Operational interface • Other engagement activities
Government	• Disclosure requirements • Submissions on discussion papers
Regulators	• Adherence to corporate policies • Disclosure requirements • Operational interface
District and regional councils	• Disclosure requirements

Stakeholder	How we identify the expectations and requirements of stakeholders
Contractors and suppliers	• Direct current feedback/interactions • One-on-one meetings
Media	• Briefing sessions • Forums and working groups • Media monitoring and editorial opportunities • Open days • Public meetings and information sessions • Sponsorship involvement
Transpower	• Operational interface • Submissions on discussion papers
Electricity retailers	• Direct current feedback/interactions • Industry collaboration • Informal contact/discussions • One-on-one meetings
Electricity industry	• Forums and working groups • Informal contact/discussions • One-on-one meetings • Open days • Participation in industry (including membership) • Public meetings and information sessions • Submissions on discussion papers

Table 2.2: How we identify the expectations and requirements of our stakeholders

2.6.3 Summarising the interests of our stakeholders

The expectations of our stakeholders are summarised in Table 2.3.

Stakeholder	Expectations
Connected consumers	• Accessibility – easy to contact provider when necessary • Consistency of service delivery (including response time) • Continuity of supply – keeping the power on • Future innovation • Health, safety and the environment • Price – keeping costs down • Quality – keeping flickering or dimming lights to a minimum • Restoration of supply – reducing length of time when power is off • Transparent communication (including outage information)
Community, representative groups	• Community focus • Corporate social responsibility • Engagement and consultation • Public safety around electricity
Other stakeholders MainPower Trust (ordinary shareholder)	 • Delivery of a secure and reliable power supply • Effective and efficient incident response • Future innovation • Health, safety and the environment • Maintaining shareholder value • Prudent risk management • Statutory/regulatory compliance

Stakeholder	Expectations
Government	• Appropriate investment in infrastructure • Delivery of a secure and reliable power supply • Future innovation • Health, safety and the environment • Industry collaboration
Regulators	• Contribution via industry consultations/submissions • Cost-reflective pricing methodology • Delivery of a secure and reliable power supply • Health, safety and the environment • Future innovation • Statutory/regulatory compliance
District and regional councils	• Appropriate investment in infrastructure • Collaboration on shared service upgrades • Contribute towards a vibrant and prosperous region • Contribution to planning via consultations/submissions • Delivery of a secure and reliable power supply • Engagement and consultation • Health, safety and the environment • Future innovation
Contractors and suppliers	• Effective contractor management • Health, safety and the environment
Media	• Effective relationship management • Timely access to information
Partners	
Transpower	• Appropriate investment in infrastructure • Collaboration and effective relationship management • Engagement and consultation • Health, safety and the environment • Transparent communication (including outage information)
Electricity retailers	• Continuity and security of supply • Effective systems and processes • Health, safety and the environment • Transparent communication (including outage information)
Electricity industry	• Collaboration • Future innovation • Health, safety and the environment • Industry participation • Information and knowledge sharing
Bankers and insurers	• Accurate and timely performance information • Confidence in Board and leadership • Good governance • Prudent risk management • Sufficient revenue to maintain asset efficiency and reliability

Table 2.3: What our stakeholders expect from us

We assess the performance of our electricity distribution network against what our consumers are telling us they want.

2.6.4 Managing stakeholder interests when they conflict

Where stakeholder conflicts arise, the priorities for managing the conflicts are ranked as follows:

1. Safety;
2. Compliance;
3. Service quality;
4. Risk management; and
5. Efficiency and effectiveness.

2.7 Accountabilities and responsibilities

Our electricity distribution network is managed and operated from our Rangiora office at 172 Fernside Road. Our ownership, governance and management structure are outlined in Figure 2.13.

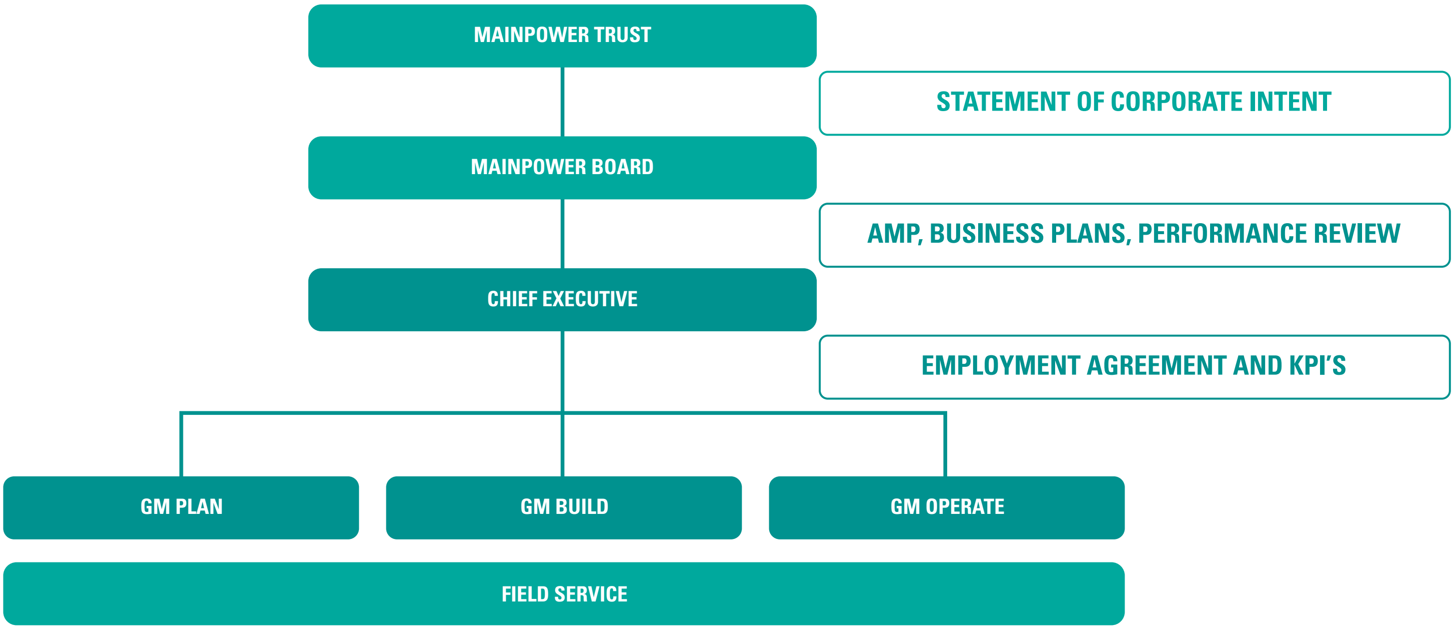


Figure 2.13: Organisational management structure

2.7.1 Ownership

We are 100% shareholder owned by the MainPower Trust, which holds shares in the Company on behalf of preferential shareholders. The Trust appoints the MainPower Board of Directors and agrees the Statement of Corporate Intent. They also provide input, on behalf of their beneficiaries, on matters of relevance to asset management planning, such as price, quality and performance.

The Trust also requires MainPower to measure and compare its performance against a selected sample of other EDBs in terms of profits, price, expenditure and electricity distribution network reliability.

2.7.2 Governance and executive leadership

2.7.2.1 Role of the Board

The Board is responsible for the overall corporate governance of MainPower. The Board guides and monitors the business and affairs of MainPower on behalf of both the Ordinary Shareholders, the MainPower Trust, to whom it is primarily accountable, and the Preference Shareholders of the Company (i.e. the Qualifying Customers in the region).

The Board's primary objective is to satisfy the shareholders' wish of enhancing shareholder value through a commitment to customer service and regional prosperity.

Customer service is measured in terms of both financial return and MainPower's ability to deliver excellence in electricity distribution system security and reliability, responsiveness to customers, quality and price competitiveness.

Regional prosperity is measured in terms of MainPower's role in leading and/or supporting regional initiatives for economic development.

The Board aims to ensure that MainPower is a good employer and corporate citizen.

2.7.2.2 Board responsibilities

The Board acts on behalf of, and is accountable to, the shareholders. The Board seeks to identify the expectations of shareholders, as well as other legislative and ethical expectations and obligations. These expectations and obligations are set out in the Board Charter, which is reviewed annually.

In addition, the Board ensures areas of significant business risk are identified by management and that arrangements are in place to adequately manage these risks.

To this end the Board will:

- provide leadership in health and safety and will ensure that employee and public safety remain at the core of the organisation so that it remains an integral part of MainPower's culture, its values and performance standards
- continue to monitor all legislation and regulatory change impacting on health and safety requirements and compliance and will ensure that they are complied with
- set the strategic direction of MainPower in consultation with management, having particular regard to rate of return expectations, financial policy and the review of performance against strategic objectives
- maintain an understanding of the electricity industry, and continue to monitor industry reform, security of supply, industry governance and Government intervention in order to identify the impact on MainPower's business
- monitor and understand the expectations and needs of the growing North Canterbury community
- remain informed about MainPower affairs in order to exercise judgement about management and its procedures
- identify risks and manage those risks by ensuring that MainPower has implemented comprehensive systems of internal control together with appropriate monitoring of compliance activities
- approve and foster a corporate culture that requires management and every employee to demonstrate the highest level of ethical behaviour
- appoint, review the performance of, and set the remuneration of the Chief Executive
- approve transactions relating to acquisitions and divestment, and capital expenditure above delegated authorities
- approve operating and development budgets, review performance against these budgets, and monitor corrective actions by management
- ensure the preparation of the Statement of Corporate Intent, interim reports and annual reports
- enhance relationships with all stakeholders.

2.7.2.3 Delegation

The Board delegates the day-to-day responsibility for the operation and administration of MainPower to the Chief Executive. The Chief Executive is responsible for ensuring MainPower achieves its business objectives and values.

The Board ensures that the Chief Executive and senior management are appropriately qualified, experienced and remunerated to discharge their responsibilities.

2.7.2.4 Codes and standards

All Directors, executives and staff of MainPower are expected to act with integrity and to promote and enhance MainPower's reputation with its various stakeholders.

Behavioural standards and accountabilities, the use of confidential information, trade practices, and health, safety and environmental management are set out in a range of formal codes, policies and procedures. These are subject to regular independent review to ensure they remain current and appropriate.

2.7.2.5 Conflicts of interest

All Directors and senior managers are required to disclose any specific or general interests that could be in conflict with their obligations to MainPower and its subsidiaries.

2.7.2.6 Board review

The Board will undertake a self-assessment of its performance and the performance of individual Directors on at least a biennial basis. The result of this review will be made available to the MainPower Trust.

2.7.2.7 Company Constitution

MainPower's Constitution sets out policies and procedures on the operations of the Board, including the appointment and removal of Directors. The Constitution specifies that the number of Directors will not at any time be more than eight nor less than four, and that one-third of the Directors will retire by rotation each year.

Non-Executive Directors of MainPower are appointed by the Ordinary Shareholders. The Board currently comprises six Non-Executive Directors.

2.7.2.8 Meetings

The Board meets 10 times a year to review, monitor, and initiate action in respect of the health and safety, strategic direction, financial performance and compliance of MainPower and its subsidiaries.

MainPower's Business Plan details matters that require Board consideration, including long-term strategic direction, operating and capital budgeting, and statutory and risk management. In addition to the scheduled meetings, the Board meets several times each year to consider specific opportunities and other matters of importance to MainPower. Annually, the Board takes the opportunity to debate and review its long-term strategic direction.

2.7.2.9 Committees

The Board has three committees, detailed below.

Safety, Health, Wellbeing and Environment Committee
The MainPower Board takes an integrated approach to managing health and safety. This is incorporated within the Risk Management Framework. The Safety, Health, Wellbeing and Environment Committee provides a concentrated focus on these high-priority areas, operating under a comprehensive charter that outlines the Committee's authority, membership, responsibilities, and activities approved by the Board.

Audit and Risk Committee
The Audit and Risk Committee operates under a comprehensive Charter, which outlines the Committee's authority, membership, responsibilities and activities approved by the Board.

Remuneration Committee
The Remuneration Committee's primary role is to advise the Board on performance reviews, remuneration policies and practices, and to make recommendations on remuneration packages and other terms of employment for Non-Executive Directors, Executive Directors and senior executives that fairly reward individual performance in relation to their contribution to MainPower's overall performance.

2.7.2.10 Risk management

The Board puts considerable emphasis on risk management, given the critical nature of this to MainPower's operations, and continually monitors the operational (including health and safety) and financial aspects of MainPower's activities and exposure to risk. "Risk Management and Compliance" is a permanent item on the agenda of the monthly meeting of Directors.
An annual review of the level and appropriateness of MainPower's insurance cover and regular reporting by management addressing the major areas of risk supports the Board's risk management process.

To fulfil its responsibility, management maintains appropriate accounting records and systems of internal control.
The Audit and Risk Committee oversees the Governance internal audit programme to ensure MainPower meets its statutory and legal requirements. The audit programme covers all levels of safety and business critical risks identified through the Risk Management Framework.

MainPower has developed a comprehensive Business Continuity Plan. This plan details the criteria and guidelines we apply to cope with a number of crisis scenarios. MainPower actively participates with the National Emergency Management Agency (Civil Defence) and other relevant agencies in order to test the plan for effectiveness.

2.7.2.11 The Asset Management Plan

The AMP serves to communicate to the Board the business' approach to asset management. Corporate objectives, expenditure, electricity distribution network and asset management performance are reported to the Board monthly.

2.7.2.12 Strategic Asset Management steering group

As part of our Network Transformation Roadmap we have also set up a Strategic Asset Management steering group. The purpose of the steering group is to oversee the strategic direction of asset management and enhance the link between the Board and asset management at MainPower.

2.7.3 Field services

All field services are managed both internally and externally. The work programme is assessed and where resourcing gaps are identified or where MainPower does not have the in-house capability, the works are outsourced. Typically, outsourcing is achieved via a Request for Proposal process. Costs are used to benchmark internal costs. The primary objective is to deliver the work programme detailed within the AMP while ensuring that MainPower benchmarks its service delivery against the market in terms of price and quality.

2.8 Overall AMP assumptions

2.8.1 Significant assumptions made

The following assumptions have been made in the preparation of this AMP.

- Residential subdivision activity will continue or plateau (and possibly reduce) during the planning period.
- Major industrial plants will maintain similar kW and kWh demand for the next five years.
- Small grid-connected DG will increase throughout the planning period, impacting financial growth but not causing significant electricity distribution network constraints.
- Existing external regulatory and legislative requirements are assumed to remain unchanged throughout the planning period.
- All projections of expenditure are presented in constant terms, as at 1 April 2024, without inflation.
- Transpower will continue to provide sufficient capacity to meet MainPower's requirements at the existing GXPs and will undertake additional investment required to meet future demand, as specified in the development plan.
- MainPower's existing corporate vision and strategic objectives will continue for the planning period.
- Neither MainPower's electricity distribution network nor the local transmission grid will be exposed to a major natural disaster during the planning period.
- During the planning period, our electricity distribution network will be exposed only to climatic (temperature, wind, snow and rain) variation that is consistent with our experience since the year 2000.
- Seasonal load profiles will remain consistent with recent historical trends.
- Zoning for land use purposes will remain unchanged during the planning period.
- EV-charging loads will not significantly affect electricity distribution network constraints within the planning period.
- All financial budgets when comparted with actual project costs will vary due to uncertainly in the supply chain, exchange rate fluctuations and inflation.

2.8.2 Sources of information

The principal sources of information relevant to this AMP are:

- MainPower's strategic planning documents, including the Statement of Corporate Intent and the Annual Business Plan and Budget
- MainPower's Asset Management Policy
- MainPower's Business Continuity Plan
- ongoing consumer surveys
- maximum electricity demand at each GXP
- regional population data and forecasts sourced from Stats NZ and the Waimakariri, Hurunui and Kaikōura district

2.8.3 Forecasting certainty

MainPower considers the following factors could lead to material differences in actual outcomes versus planned outcomes. However, as the AMP is updated annually, any differences would likely exhibit as a linear change (i.e. not a step change) and would be anticipated in advance.

Changes in demand factors can affect future development plans the most significantly. Growth that is higher than forecast brings forward the need for investment in additional capacity, security, reliability or increased load management, while growth that is lower than expected can sometimes allow development plans to be deferred.

Uncertainties within our demand assumptions include the following:

- The rate of growth in demand could significantly accelerate or decelerate within the planning period.
- Dry/wet years could affect irrigation demand.
- Significant land-zoning changes may be implemented within the region.
- Significant new loads may require supply increases.
- Large existing loads may reduce or cease demand.
- Consumers could change their requirements for reliability and/or their willingness to pay for higher/lower levels of service.

Changes in operational factors may require us to reprioritise or reallocate our planned operating expenditure in the short term and increase or decrease operating expenditure or renewals allowances in the medium term. Changes may include the following:

- The electricity distribution network could experience major natural disasters such as earthquake, flood, tsunami or extreme storm.
- Significant storm events could divert resources from scheduled maintenance.
- Regulatory requirements could change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.

We have assessed the level of certainty of forecasts relevant to different consumer groups within this AMP's planning period as shown in Table 2.4.

Timeframe	Location	Constraint	Proposed remedy
Year 1	Reasonable certainty	Reasonable certainty	Reasonable certainty
Year 2–3	Some certainty	Reasonable certainty	Reasonable certainty
Year 4–6	Some certainty	Little if any certainty	Some certainty
Year 7–10	Some certainty	Little if any certainty	None

Table 2.4: Planning certainty

2.8.4 Escalation index

Our input prices are subject to a range of cost pressures, including those that apply to skilled and unskilled labour, material components (e.g. copper, aluminium, steel), the NZD exchange rates and other inputs such as fuel. We have applied the Westpac Economics Forecast Summary Spreadsheet values for the purpose of converting our constant price forecasts to nominal terms, as given in Table 2.5.

Year	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Index	1.05	1.09	1.12	1.14	1.16	1.19	1.21	1.24	1.26	1.29

Table 2.5: Escalation Index based on Westpac Economics Forecast Summary Spreadsheet 03 November 2023

2.9 Sources of uncertainty

The following factors could lead to material differences in actual outcomes versus planned. However, as this AMP is updated annually, it is expected that any material differences would be anticipated in advance.

2.9.1 Demand factors

Changes in demand factors most significantly impact future development plans. Growth that is higher than forecast can bring forward the need for investment in additional capacity, security or reliability, while growth that is lower than expected can sometimes allow development plans to be deferred. Uncertainties within our demand assumptions include the following:

- Within each region, load patterns could change, resulting in a movement from summer to winter peaks or vice versa.
- Significant land-zoning changes may be implemented within the region.
- Dry/wet years could affect irrigation demand.
- Significant new loads may require supply.
- Large existing loads may reduce or cease demand.
- Customers could change their requirements for reliability and/or their willingness to pay for higher/lower levels of service.
- Significant distributed generation, greater than 10% of its connected substation capacity, may be commissioned within the network supply area.

2.9.2 Operational factors

Changes in operational factors may require us to reprioritise or reallocate our planned maintenance in the short term and increase or decrease maintenance or renewals allowances in the medium term. Changes may include the following:

- The network could experience major natural disasters such as an earthquake, flood, tsunami or extreme storm.
- Significant storm events could divert resources from scheduled maintenance.
- Regulatory requirements could change, requiring MainPower to achieve different service standards, health and safety standards, or design or security standards.
- Unforeseen equipment failure could require significant repair and possibly replacement expenditure.
- Asset management planning that is more detailed, undertaken over the next 3–5 years, could generate development and maintenance requirements that significantly differ from those currently provided for.

2.10 Systems and information management

The core of all MainPower's Asset Management is our CMMS. The CMMS adopted by MainPower is referred to as the "OneAsset" system. OneAsset is an enterprise resource planning (ERP) tool primarily designed to support financial reporting and operating assets management, through to works and human resources management.

2.10.1 Asset lifecycle management – maintenance and replacement

Preventative maintenance programmes are detailed in MainPower's Maintenance Standards. These are developed for all MainPower asset fleets. The Maintenance Standards are continually reviewed, based on the life and performance analysis of the asset fleets. The backbone of the analysis is asset data. The data (inspection, condition and defects) are collected when carrying out maintenance activities and inform asset health and replacement strategies. See Figure 2.14.

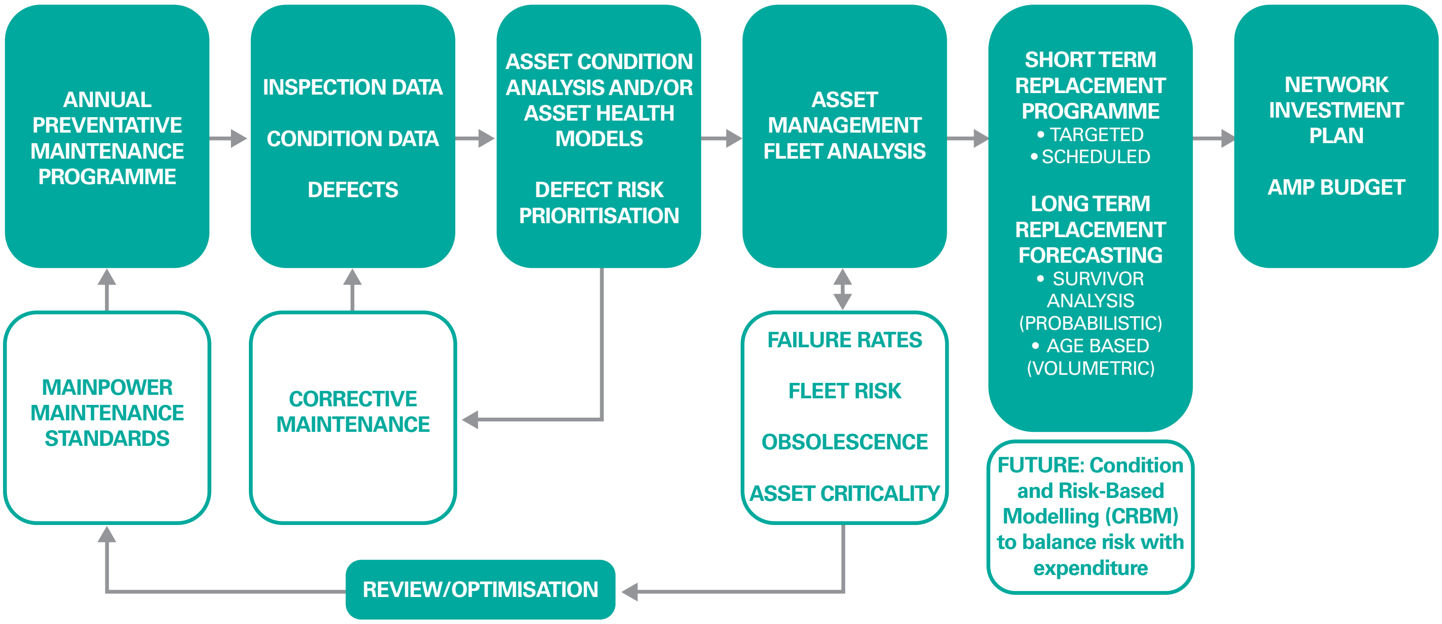


Figure 2.14: Asset lifecycle management

The asset data are collected and stored in several locations, such as the ERP, GIS and data warehouse systems. This currently presents a risk to the organisation in terms of the integrity of the data and the ability to make good asset management decisions. The aim is to develop a single source of the truth for all asset data within the ERP system, including the implementation of strategic asset management. Currently, renewals are informed primarily by defects and age. The future includes implementing a targeted scheduled replacement programme informed by asset condition, criticality and risk.

2.10.2 Limitation of asset data and improvements

MainPower holds good information on our assets. The focus in the future is to centralise all asset data, including vegetation, into a single source of information: TechnologyOne Enterprise Asset Management. A project to achieve this is underway and will provide the foundation for the automated logging of maintenance and condition assessment of all maintenance activities. All maintenance activities allow for asset data to be updated through inspections or routine maintenance.

MainPower has completed a review of our asset data, including consistency of data across multiple systems and the ability of data to support future strategic asset management. While the data currently supports MainPower's AMP and work programme, we aim to improve the quality and consistency of our data.

2.10.3 Electricity distribution network planning

The planning for electricity distribution network growth is informed by load, connection growth, connection of new technologies and customer projects. This change in capacity requirement is assessed against existing capacity, security of supply standards and reliability. At this point, a decision may be made to implement a tactical solution for increased capacity, such as reconductoring or voltage regulator deployment. Alternatively, a decision may be made to upgrade a GXP or zone substation, which is more expensive. The tactical upgrades are primarily used to defer capital expenditure that is more expensive. All capacity upgrades are referred to a capital-sanctioning process. The electricity distribution network planning process is illustrated in Figure 2.15 below.

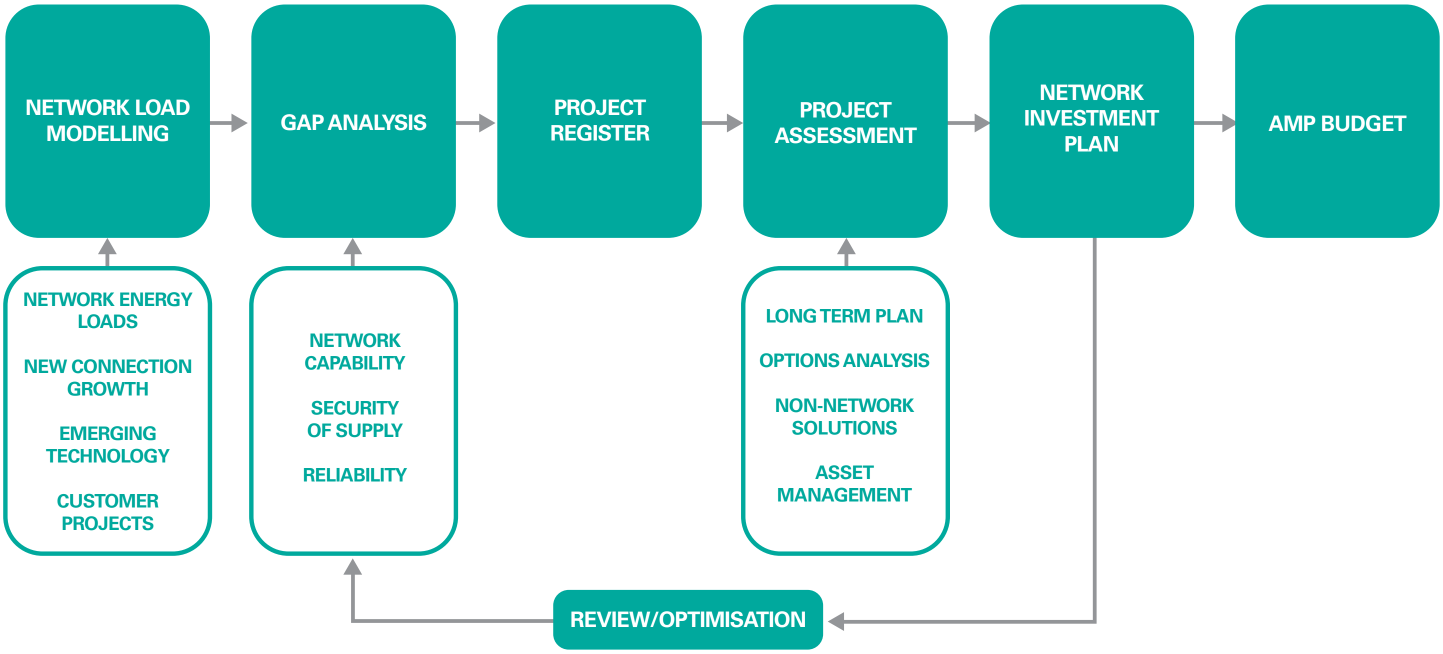
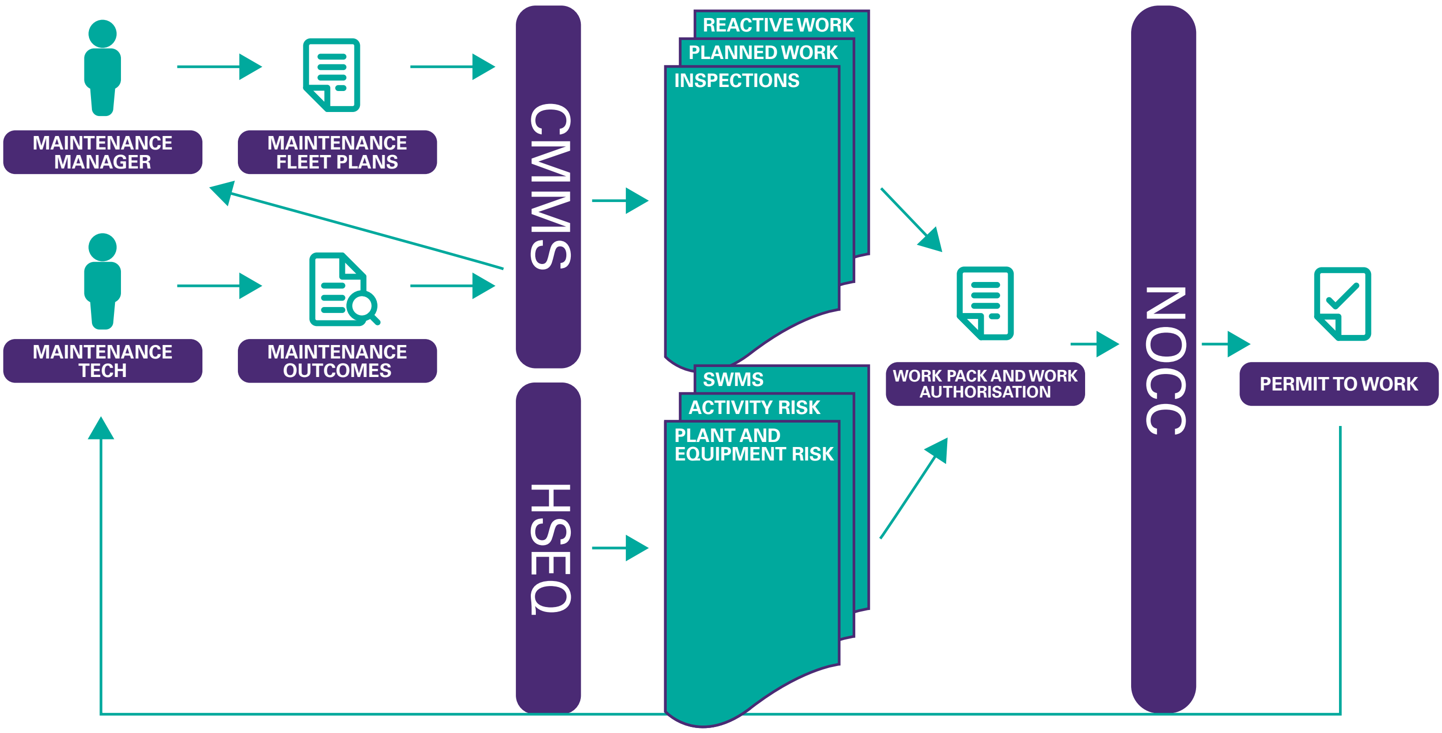


Figure 2.15: Electricity distribution network development

2.10.4 Maintenance Processes

The requirement to deliver maintenance on our assets is defined in MainPower's Asset Maintenance Standards. The standards are implemented within MainPower's CMMS ERP system. Figure 2.16 summarises the asset management workflow process, including the need to work within a controlled working environment, the issuing of authorisation, and the receiving of asset condition data that is used to manage defects and inform renewals.



Note. CMMS = computerised maintenance management system; HSEQ = health, safety, environment and quality; NOCC = Network Operations & Control Centre; SWMS = safe work method statement

Figure 2.16: Asset maintenance workflow process

2.10.5 Measuring electricity distribution network performance

MainPower maintains an ISO 90001-certified quality assurance programme and continues to develop, implement and internally audit the programme in accordance with this commitment. Relevant standards for asset management planning include design, purchasing, document and record management, and environmental management. MainPower maintains a document control system under this certification.

The ISO 90001 certification ensures annual review and continual improvement of the documentation systems.

Where asset management design and construction are outsourced, contractors must comply with our asset management processes, controls and documentation systems. All maintenance tasks and asset data collection are maintained within the MainPower CMMS against the applicable asset. Costs associated with the maintenance are linked back to the asset via the work order.

2.11 Communication and participation

MainPower communicates its asset management strategy, objectives and outcomes to stakeholders as outlined in Table 2.6.

Reporting from/to	Reporting type
MainPower Trust to consumers and the wider community	• Consultation on the Trust's Letter of Expectation to the MainPower Board • MainPower Trust's Annual Report and audited accounts
MainPower Board to MainPower Trust	• Statement of Corporate Intent • Company Annual Report, including Chair and Chief Executive's statements and audited accounts • Annual information disclosure • Twice-yearly presentation, including financial and operational performance
Chief Executive to MainPower Board	• Chief Executive's statement in the Annual Report, including narrative of the year's highlights • Monthly MainPower Board report, including progress on capital and maintenance programme • Monthly update on network performance and major incidents
General Manager Network Planning & Strategy to Chief Executive and MainPower Board	• Annual report on budget and major projects • Monthly report, including year-to-date performance and progress against budget • Individual reports on major projects • Daily updates on areas of concern, including health and safety
Managers	• Weekly direct reporting from team meetings • One-on-one discussion with direct managers • Daily updates during brief meetings, including health and safety updates • Monthly management accounting reports
Field Services Supervisors	• Weekly progress reports • Monthly meetings on progress to budget
External contractor to General Manager Field Services	• Weekly progress reports • Monthly meetings on progress

Table 2.6: Reporting on asset management

3. SERVICE LEVELS AND PERFORMANCE EVALUATION

MainPower's electricity distribution network and business service levels, and the performance achieved, are an integral part of the decision-making processes throughout the organisation. We are committed to listening to our customers and stakeholders and better understanding their needs. This allows us to monitor and improve the services we provide continuously, throughout our region, now and into the future. We use a range of engagement methods to find out what customers expect of MainPower and their vision for the future. We believe we have balanced legislative, regulatory and stakeholder requirements in our defined service levels. This section outlines how we engage with our customers, what they expect from us, and how this translates through to our service levels.

3.1 Customer engagement

We provide electricity distribution services to more than 44,000 homes and businesses across the Waimakariri, Hurunui and Kaikōura regions in the South Island of New Zealand. Types of consumers include residential, commercial, large commercial or industrial, irrigators, council pumps, streetlights and individually managed consumers (see Table 3.1). Partners include retailers as well as DG owners and operators.

Understanding customer expectations, monitoring, and improving the service MainPower provides are all vital if we are to establish and maintain trust and goodwill with our customers and stakeholders throughout the region. We do this by actively consulting with our customers via surveys conducted internally and by research agencies. This information is important to our forward planning, as the electricity industry is entering a time of transformation as emerging technologies change the way consumers use and manage energy.

Consumer type	Average number of ICPs	% of ICPs	Units delivered (GWh)	% of Units delivered
Residential	35,868	81.3%	302	48.7%
Commercial	6,414	14.5%	127	20.5%
Large commercial or industrial	42	0.1%	58	9.4%
Irrigators	1,466	3.3%	67	10.8%
Council pumps	207	0.5%	13	2.1%
Streetlights	111	0.3%	4	0.6%
Individually managed consumer	1	0.0%	49	7.9%
Total	**44,109**	**100.0%**	**620**	**100%**

Note. ICPs = installation control points; GWh = gigawatt-hours

Table 3.1: Electricity consumption and consumers, by consumer category

3.1.1 Customer engagement programme

MainPower undertakes a comprehensive suite of customer engagement initiatives every year to collect feedback and information from our customers across a variety of areas. See Table 3.2 below for more detail on MainPower's regular customer engagement.

MainPower Customer Engagement Programme			
Engagement type	**Frequency**	**Numbers**	**Purpose**
AMP Service Experience Survey	Ongoing	All customers who have interacted with MainPower are invited to participate at the conclusion of their job or request.	To gather AMP performance statistics on customers who have engaged with MainPower for customer-initiated work, including new connections, new power supplies or changes to power supplies. Measurements include: • engagement effort – how easy it is to do business with MainPower • staff friendliness – to ensure the engagement is proactive and results oriented • quality of work – to ensure we deliver a standard of work that is aligned with our consumers' expectations • timeliness – to ensure work is delivered in accordance with our consumers' expectations • communication – to ensure we communicate with our consumers proactively • staff reliability – to ensure our staff deliver services to our consumers as agreed • price – to ensure our pricing is fair.
Customer Pulse Survey	Annual	Minimum of 200 phone and 200 online survey completions.	To gather customer perceptions of MainPower. Same focus areas each year covering overall satisfaction, brand awareness, outage communications, community support and effectiveness of safety campaigns.
AMP Customer Engagement Sessions – World-Café Style	Every two years (alternates with AMP Future Networks Survey)	20–24 attendees per session (4–6 per group rotating around four stations). Three sessions held – Waimakariri, Hurunui and Kaikōura.	Receiving qualitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covering reliability, future technology, resilience and safety. Opportunity to include other topical subjects (e.g. pricing).
AMP Customer Engagement Survey	Every two years (alternates with AMP Future Networks Survey)	Minimum of 1,000 online responses.	Receiving quantitative feedback from residential, rural and commercial/business customers in each main region (Waimakariri, Hurunui and Kaikōura). Covering reliability, future technology, resilience and safety. Opportunity to include other topical subjects (e.g. pricing, environment and community sponsorships).
AMP Future Networks Survey	Every two years (alternates with AMP Customer Engagement Sessions and Survey)	Minimum of 1,000 online responses.	To gather information on topics related to future network planning (e.g. technology adoption). This information is used to help inform the AMP.
EDB Benchmarking Survey	Ad hoc	Around 800–1,000 responses.	To get an understanding of how MainPower is performing in core areas compared to other EDBs that choose to participate in the survey.

Table 3.2: MainPower customer engagement programme

3.2 What consumers have told us

According to the feedback from the FY23 surveys, MainPower customers have high satisfaction levels overall, in line with the results of previous years.

MainPower customers continue to have high satisfaction:

- 55% rated MainPower's performance and services as positive
- 91% rated their electricity as "reliable" or "very reliable".

Both results are consistent with previous years.

Key measures are back up after a slight decline in FY22. MainPower must continue this growth.

- After small decreases last year, satisfaction with the majority of MainPower's perceptions has remained stable or increased in FY23.
- While differences are not significant, satisfaction with price dropped to below half (45%) for the first time in FY23.

Recall of outages reached an all-time high in FY23. This reflects the more intensive maintenance programme MainPower had undertaken.

- Two-thirds (67%) of respondents could recall at least one outage in FY23.
- Outage recall was particularly high among rural residents and customers located in Hurunui.

However, notice of planned outages also reached an all-time high (95%). This aligns with MainPower's efforts to improve customer engagement in relation to outages, including when outages are changed or cancelled (acknowledging the retailer is not always able to communicate these changes to their customers). Other research projects conducted by the same research agency have found decreasing satisfaction levels in surveys across all industries. This, along with anecdotal evidence and the results of an environmental scan, suggests that there are levels of fatigue in the nation that may be reflected in satisfaction survey results. The continued stable nature of MainPower's high scores is a sign of success.

3.2.1 Consumers – performance and service

Customers remain highly satisfied with MainPower's performance and service, as demonstrated in figure 3.1.

- There have been no statistically significant changes in satisfaction levels since 2017.
- The "Net Positive Score" has bounced back to above +40, after a slight lull in 2021.
- Contrary to previous years findings, Kaikōura residents were found to have the highest satisfaction of all regions, with two thirds of respondents (66%) rating MainPower's performance and service positively.
- Hurunui residents were found to be the least satisfied (46%).

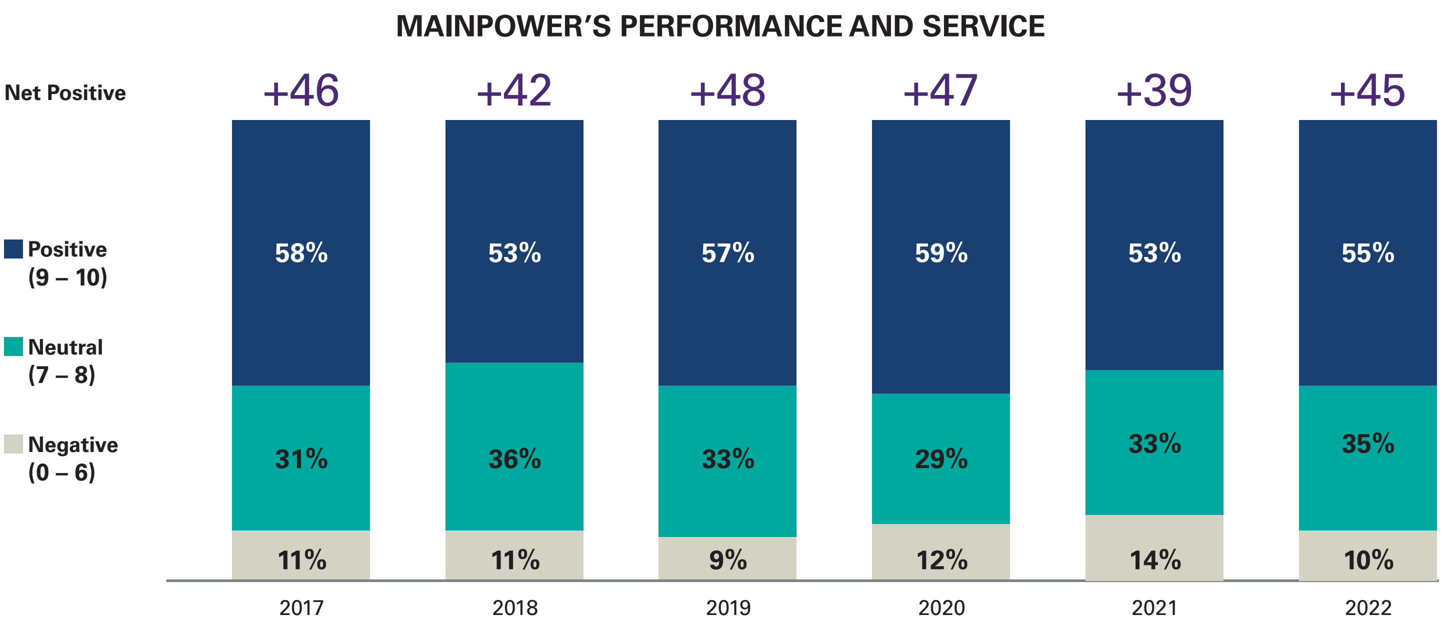


Figure 3.1: MainPower consumers' perceptions of our performance and service (Source: MainPower's Customer Pulse Surveys FY18–FY23)

3.2.2 Consumers – Reliability

High levels of satisfaction are driven by positive perceptions of reliability, see figure 3.2.

Perceptions of reliability continue to differ between regions and customer types.

- Customers in Hurunui are significantly more likely to think their power is "very unreliable".
- Customers located in Waimakariri and residential areas continue to be significantly more likely to think their power is "very reliable".

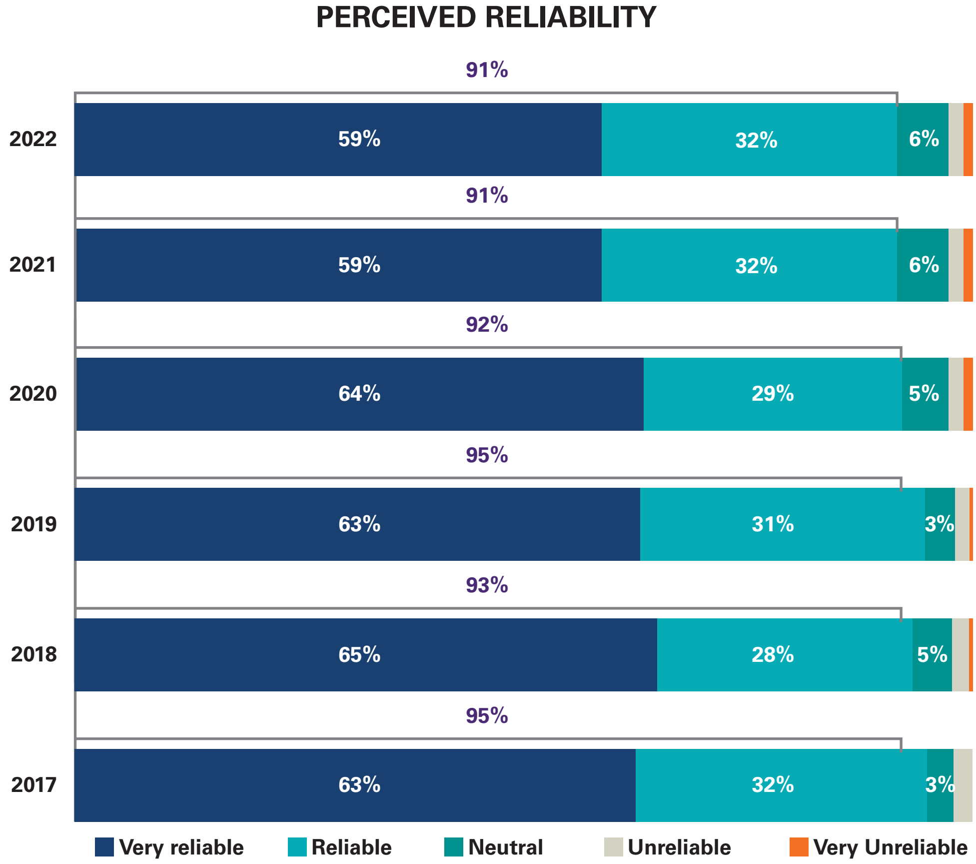


Figure 3.2: MainPower customers' scores for our reliability (Source: Customer Pulse Survey FY23)

3.2.3 Consumers – Supply continuity, quality, restoration and price

MainPower delivers strongly in all important service areas, except for price. Keeping costs down is perceived as vital, but satisfaction with price was low. See Figure 3.3.

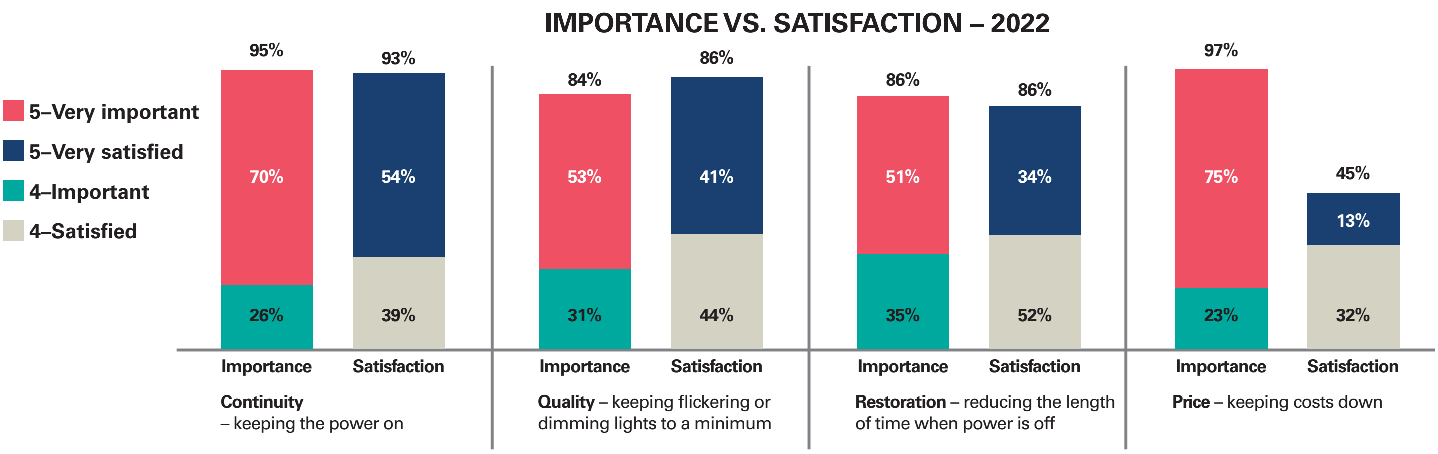


Figure 3.3: MainPower customers' scores regarding importance and satisfaction across service areas (Source: Customer Pulse Survey FY23)

3.2.4 Consumers – Safety messaging recall

Prompted recall of safety messages remains very high and is similar to previous years. See Figure 3.4.

- Kaikōura residents were significantly less likely to recall safety messages (79%) compared to other regions.
- Rural customers were slightly more likely to recall seeing messages about "No power? Call us first" (47%). MainPower has continued to meet its responsibility to provide relevant safety messages through a range of traditional and digital channels.

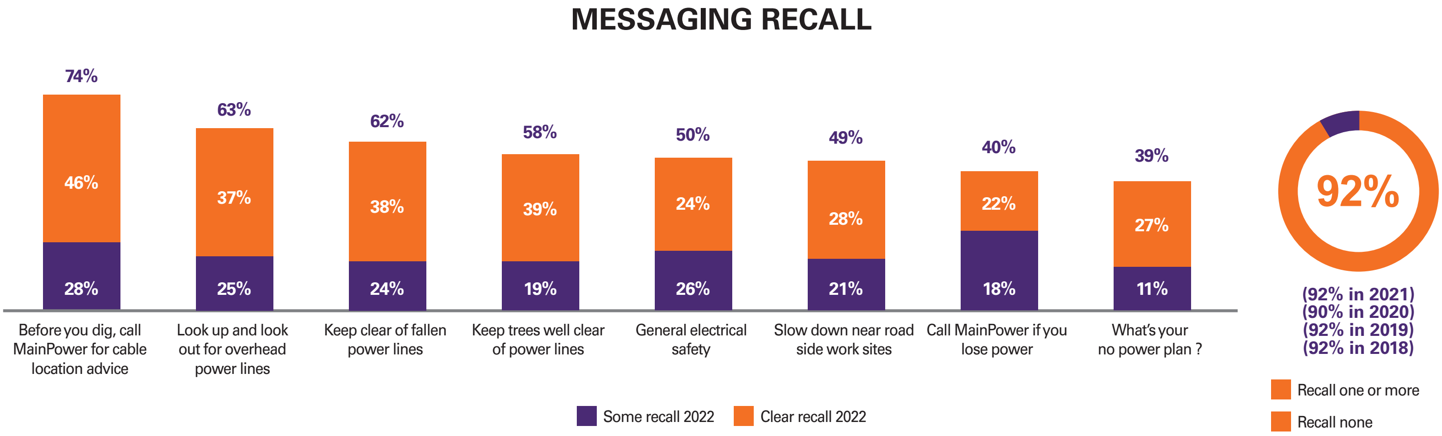


Figure 3.4: MainPower customers' recollection of safety messaging (Source: Customer Pulse Survey FY23)

3.2.5 Asset Management Plan customer engagement

In March 2023, MainPower conducted our AMP Customer Engagement Sessions covering key areas relating to the AMP, including reliability, resilience, future networks (future technologies), and environment. There were 20–24 attendees per session, who were divided into four groups:

- Group one: Residential customers
- Group two: Rural customers
- Group three: Commercial/business customers
- Group four: Mixed customers.

The sessions were held in three locations to ensure all regions were represented:

- Waipara (Hurunui)
- Rangiora (Waimakariri)
- Kaikōura.

3.2.5.1 'MainPower Money' exercise

Participants are asked to invest $1 million of fake 'MainPower Money' at the beginning of their session and again at the end of their session after learning more about the four key areas in Figure 3.5, and the changes in investment are recorded.

Figure 3.5: Four key areas for AMP Customer Engagement Sessions

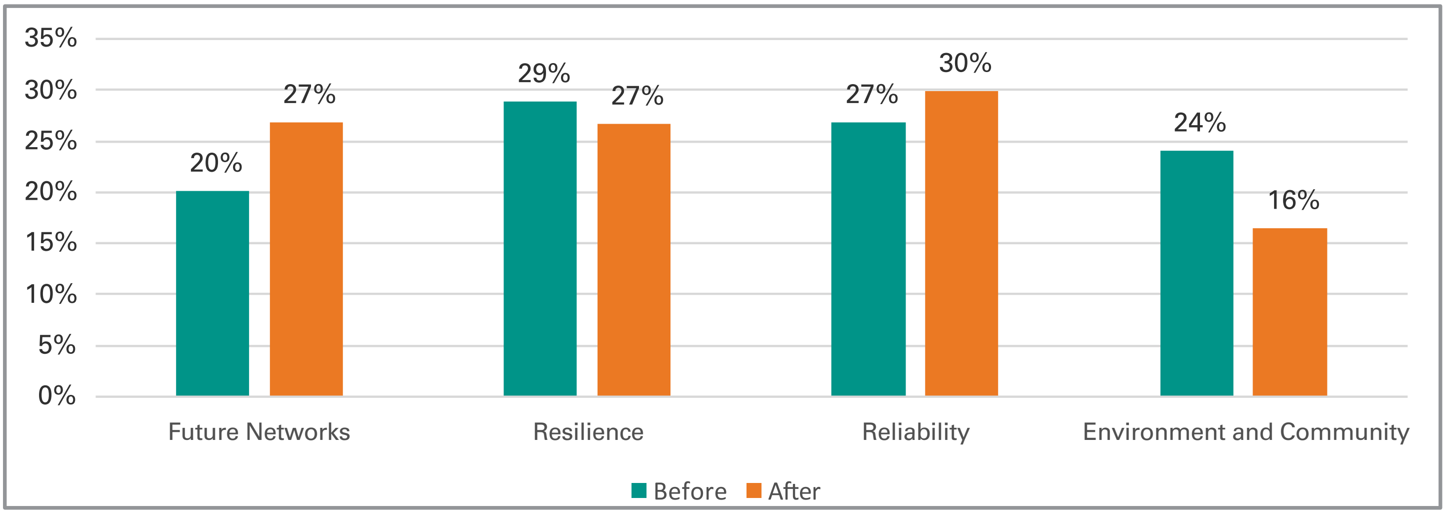


Figure 3.6: Results from the 'MainPower Money' exercise conducted at the AMP Customer Engagement Sessions in 2023

3.2.5.2 Reliability feedback

- Most customers in attendance would be comfortable with ~2 planned outages per year. Per installation control point (ICP), MainPower is currently at 0.8 for FY23.
- For those customers who have lived within the MainPower network for a significant amount of time, they explained that the reliability had improved for them in the last 10+ years.
- A need was expressed for more timely and improved communications about upcoming outages as retailers could not always be relied upon.
- Customers want to be told when there is going to be a change to a planned outage (e.g. time or date or if the outage is running late). Often these changes occur in timeframes that do not allow for retailers to contact their customers.
- Customers were pleased that as a result of previous engagement sessions, MainPower would be sending texts to a dvise of power outages. They believed this would alleviate some of the issues experienced.

3.2.5.3 Resilience feedback

- All customer groups were satisfied with the current resilience of MainPower's network and understood that there would likely be power interruptions as a result of a significant event (e.g. snowstorm or earthquake). However, the amount of time they could manage without electricity varied. Generally, customers expect power on sooner and are less tolerant of long outages (compared to 2019 AMP research).
- There was a strong tendency for the rural customer groups to be more resilient. They would be comfortable for longer periods without power than the residential and commercial customers, who tended to be less resilient and felt they would need power back on a lot sooner (however, this did depend on the type of business and industry they were in).
- Many elderly participants relied solely on heat pumps/electricity for heating and would struggle if power was off due to a significant event, especially in winter.
- Around 50% of commercial customers had back up no-power plans (e.g. generators, processes to follow in the event of a power outage).

3.2.5.4 Future technologies feedback

- Most of the customer groups showed an interest in solar power and electric/hydrogen vehicles. After further explanation there was also an increase in interest in peer-to-peer trading.
- Kaikōura was not interested in EVs due to location (range was an issue) and types of EVs available at present not being suitable for the terrain they may experience. They were more open to hydrogen vehicles.
- Wind turbines were of interest as long as they were not near the customers' properties. Customers believed wind energy could further support the reliability of the overall electricity supply in New Zealand and reduce the amount of coal imports.
- Customers expressed a strong desire for MainPower to be innovative, invest in innovative future technologies/R&D and to be a leader around innovation. Not 'bleeding edge' but 'leading edge' – a fast follower.
- Customers believed investing in enabling consumer choice around adoption of future technologies would have a very positive influence on the environment (this was reflected in the 'MainPower Money' exercise).

3.2.5.5 *Environment and community feedback*

- Generally, customers wanted MainPower to be proactive when it came to making positive environmental choices.
- Some customers wanted MainPower to provide incentives to encourage them to switch to electric options and make choices that would lower carbon emissions (e.g. solar, LEDs, EVs).
- Customers recognised MainPower's influence was limited given our industry; however, they would like us to be conscious of where goods are procured from and buy local where possible.
- Customers wanted MainPower to continue to support environmental initiatives through our sponsorship portfolio, including supporting smaller community groups undertaking work like pest control, tree planting, and protecting endangered species.
- Of the three regions represented, Kaikōura felt they weren't represented equally in sponsorship distributions.

3.2.5.6 *AMP customer engagement quantitative feedback*

After conducting the in-person world-café style sessions, a survey is sent to MainPower customers to gather quantitative feedback on the same topics. Key findings from the AMP Customer Engagement Survey are as follows.

- Over nine in ten respondents (92%) feel that it is very important for MainPower to be prepared for significant events. This is an increase from 89% recorded in 2022. This is most likely the result of an increase in the number of severe weather events that have affected New Zealand over the past 12 months.
- Over six in ten network customers (64%) believe that one to two planned outages per year is acceptable.
- Commercial customers have considerably lower satisfaction in MainPower's response to unplanned outages when compared to residential customers.
- The main opportunities for improvement include:
    - demonstrating to customers that lines charges are good value for money.
    - ensuring that there is sufficient communication with customers about work that MainPower is doing in their area, including power supply matters
    - making customers more aware about what work is being planned in their area and how the lines charges that they pay are contributing to network resilience and the support of local communities.

3.2.5.7 *Key findings related to the adoption of new technologies* ***(from AMP quantitative feedback)***

- A large proportion of customers (60%) believe it is important for MainPower to enable a low-carbon future in North Canterbury.
- Technology adoption is considerable and has improved over the past 12 months (LED lighting +13%, EV +4%, battery storage +2%). High upfront costs remain the main barrier to the adoption of new technologies.
- Electricity is the main source of heating used by over five in ten customers (55%).
- Rural customers, as well those in the Hurunui region, are the most likely to be using wood burners, which is higher than the proportion of those in these areas using electricity for heating.
- Just under seven in ten customers (67%) have LED lighting in their homes or businesses. Just over one in four (26%) use gas for hot water or heating.
- There is a significant uptake of new technologies when compared with the results in 2022.
- 76% of those who own an EV charge them at home. A further 6% charge their vehicles at work.
- The main reason customers give for being unlikely to purchase an EV is the cost (48%).
- Seven in ten customers who have solar panels also have an export/import meter installed.
- The main reasons customers give for being unlikely to install solar photovoltaic panels are the upfront costs being too high (43%), and that it takes too long to recoup the upfront cost (29%).
- 55% of customers do not have a back-up power supply.
- Significantly more rural customers and businesses have decided to purchase a back-up power supply.
- 9% of customers are likely to install a back-up power source in the next 12 months.
- The main reasons customers give for being unlikely to install a back-up power source are upfront costs (60%) and no need to have one (27%).

3.2.6 Asset Management Plan service experience survey

Customers who have interacted with MainPower are invited to participate at the conclusion of their job or request.

To gather AMP performance statistics on customers who have engaged with MainPower for customer-initiated work, including new connections, new power supplies or changes to power supplies. Measurements include:

- Communication – to ensure we communicate with our consumers proactively.
- Timeliness – to ensure work is delivered in accordance with our consumers' expectations.
- Staff friendliness – to ensure the engagement is proactive and results oriented.
- Quality of work – to ensure we deliver a standard of work that is aligned with our consumers' expectations.
- Website – to ensure the website application process is optimised for the user.
- Price – to ensure our pricing is fair.
- Engagement effort – how easy it is to do business with MainPower.

Please note, MainPower prefers to use an Engagement Effort measurement over the Net Promoter Score As customers do not have a choice as to whether they can change their lines company, we believe the customer effort question better reflects the satisfaction perceptions of the customer compared to the standard Net Promoter Score question.

Please see the FY23 AMP Service Experience results in Table 3.3 below. These satisfaction are measured on a scale of 0-10 (0 being very dissatisfied and 10 being very satisfied; for engagement effort 0 is very difficult and 10 is very easy to get the work completed or enquiry resolved).

	Network Services	Service Delivery	Vegetation	MainPower Overall	Suggested Target
Communication	7.92	6.15	6.65	6.91	7
Timeliness	7.98	6.10	5.74	6.61	7
Friendliness	8.39	7.55	7.20	7.55	7
Website	7.75	6.26	-	7.01	7
Price	-	5.41	4.95	5.18	5
Quality	-	7.27	-	7.27	7
Engagement effort	7.4	5.5	6.04	6.31	7

Table 3.3: AMP Service Experience results FY23

3.3 Maintaining performance indicators

MainPower periodically reviews its performance against its performance indicators in a Plan–Do–Check–Act cycle that is aligned with MainPower's accreditation to ISO 9001, as described in Figure 3.5.

Note. SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index

Figure 3.7: MainPower's performance indicator continuous improvement process

3.3.1 Inputs

These are based on:

- the customer expectations revealed in the customer engagement surveys (discussed earlier in Section 3.2)
- analysis and industry benchmarking across our peer group (to be discussed in Section 3.6.7).

3.3.2 Planning

Using the above inputs, MainPower's network development and asset management guidelines have been refined to include:

- Security of Supply Standard
- Asset Portfolio Strategies, including asset health (CBRM) models
- Project and Works Delivery Planning and Processes
- Network Operating Standards
- Network Architecture Standards
- Network Reliability Strategy.

3.3.3 Work programme

MainPower's asset management guidelines are used to inform a targeted AMP work programme and budgeting/resource planning, including:

- asset replacement/renewals
- reliability and security of supply-focused network reinforcement and major capital projects
- a refined and targeted network maintenance programme
- refined network engineering and design practices.

3.3.4 Performance monitoring

- Internal data is analysed to monitor historical service levels, including feeder reliability, root cause and common mode failure analysis, and predictive modelling is applied.
- Network service-level performance is continuously monitored, with analysis of network outages and monthly reporting of SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) indices to the MainPower Board against year-to-date forecasts, and specific investigations are conducted into the causes of major outages.

3.3.5 Analytics

Continuous improvement principles are employed to feed back the insights from the performance monitoring, data analytics and outage investigations into annual updates of MainPower's electricity distribution network development and asset management documentation. This is combined with other inputs to better understand, inform and refine future service levels.

3.4 Customer services practices – complaint management

3.4.1 Planning and managing customer complaint resolution

Our complaints process is documented within process flow software (Promapp) for all team members to access. All customer interactions are recorded and managed in MACK, MainPower's Salesforce CRM. As well as MainPower employees interacting with customers, MainPower also uses a third-party call centre service called CallCare to answer customer telephone enquiries.

The Promapp complaints process aims to provide guidance on how to process complaints submitted to the business and provide a solution to the customers that is fair and reasonable.

The following information is provided to staff via a Promapp complaint process guide.

a) Managing customer complaints
A complaint is defined as an expression of dissatisfaction made to or about a provider where a response or resolution is explicitly or implicitly expected. Complaints can be received over the phone, email, via the MainPower website, in a letter, or in person (e.g. verbally reported to field services while at a job site or if a customer visits the MainPower office).

The goal is for a complaint to be addressed or resolved at the initial point of contact, where possible. Following a resolution, a summary of the interaction entered is into MACK. If the complaint is not resolved during initial contact with the customer, it is reported to the business via MACK and managed via our complaint process.

A complaint investigation is managed by MainPower's Corporate and Customer Relations team. During the investigation key information about the customer and complaint is gathered, including any supporting documentation or images.

Customer complaints must be acknowledged, in writing, to the customer within two working days. The acknowledgement must also include a copy of the complaint resolution process and information about Utilities Disputes – an independent service that assists with complaint resolution.

Following the acknowledgement, MainPower aims to resolve the complaint within five working days. However, if further time is needed to complete a thorough investigation, the process does allow for up to 20 working days with an additional extension of 20 working days by mutual agreement with the customer. Following the investigation, a proposed resolution is approved internally prior to being presented to the customer. If the resolution is accepted by the customer, once the resolution has been processed, the complaint is closed. If the resolution is not accepted, then the complaint is placed in 'deadlock' and the customer is advised that they can submit a dispute to Utilities Disputes, if they would like to continue finding a resolution.

If Utilities Disputes accepts the complaint, they will manage MainPower and the customer towards an agreeable resolution.

3.5 Practices for new connections and altering existing connections

3.5.1 Approach to planning and management of new connections

3.5.1.1 New connections

New connections apply to situations where an electricity distribution network connection is already available at the property boundary, in the location where the connection will take place, with adequate capacity. If no power connection is available at the boundary, a separate process must be followed to extend the distribution network and install a new power supply (distribution network electrical infrastructure build). This process follows a different path and timeline and is not discussed at length in the following answers.

MainPower's website allows customers to access a range of information about MainPower's new connection process, including making online applications for new connections (offtake and injection connections). All new connection applications must be made online through our website. New connection applications are normally completed by electricians and/or DG installers who are experienced with the process, on behalf of the customer. MainPower's team of Network Services Representatives are available during business hours to assist customers and electricians with such applications in person, by phone, or by email.

Offtake-only connections are processed quickly using an integration between the website and our internal systems. The application only needs to be reviewed and approved, at which point the system generates a connection advice sheet that instructs the customer/electrician how to connect to the network. Here we provide specific advice intended to be read by the electrician, to avoid some common problems like connecting to the wrong number of phases, connecting to the wrong supply point, or failing to run cabling close enough to the supply point.

MainPower then updates the registry with the trading information for the ICP to be livened and advises the customer's chosen energy retailer. Once the energy retailer accepts the customer/new connection and advises the metering equipment provider (MEP), the livening agent undertakes the final connection, which allows the power to flow. Once MainPower has received the necessary information back from the livening agent to confirm the ICP is live, MainPower then updates the registry to show the ICP has been livened by the network.

There are many parties involved, which complicates the process and can lead to delays if one party fails to complete all their responsibilities in a timely way. This also means the overall timeframe for new connections can vary, although each party works quickly. Early new connection applications are important to ensure consumers are connected within a reasonable time. MainPower works with metering providers and livening agents to ensure this happens, and MainPower has contracted with all the willing livening agents in our area.

Injection connections, also known as DG connections, are more complex, and the processing time varies with the size and compliance considerations of the application. They can only be installed on ICPs that have already completed the above process as a "permanent" connection. Again, all applications must be made online, and assistance is available from our Network Services Representatives. MainPower processes the online DG connection application and confirms it meets the requirements of Part 6 of the Electricity Industry Participation Code. Conforming applications then receive a DG Approval Notice, which is sent to the customer and installer. The installer is subsequently required to supply MainPower with the necessary compliance paperwork and must send the energy retailer a copy of our notice, so they may upgrade the installation's metering to import/export metering at the correct point in the process. One common issue is DG being connected without following the necessary approval processes with the network. MainPower undertakes weekly and monthly checks of registry and billing information to identify those ICPs with DG installed but without a DG Approval Notice issued. In these situations, we seek retrospective compliance paperwork from the consumer/installer. The one group of DG connections we cannot check for is those where DG is physically installed but no application has been made either to MainPower as distributor or the consumer's retailer.

3.5.1.2 Alterations to existing connections

Alterations to existing connections generally follow the same practices as outlined above. Typical alterations to a connection include going from a temporary supply to a permanent supply, upgrading a supply to include DG, or decommissioning an ICP, which follows a different process to all the others explained above.

Decommissioning (permanently disconnecting an ICP from the electrical network) is only completed on request from the energy retailer. Upon request, MainPower dispatches an employee to site, removes the physical electrical connections to the installation, makes those connections safe, and removes the electricity meter. The electricity meter is returned to the MEP. MainPower will then update the registry to show the ICP has been decommissioned, advising the retailer.

3.5.2 Minimising cost to the consumer

MainPower aims to encourage a competitive commercial environment in our geographic region for services related to connection and livening. We have authorised a number of different livening agents and set few barriers to entry for new parties. We give customers a choice of livening agent when they connect to our network, and a choice of contractors if they require a network extension.

We actively encourage the use of local electricians whenever possible, in preference to MainPower doing work on-property. We allow a wide range of parties to access and work upon our electrical network connection points, without access costs, subject to a range of standardised safety measures.

MainPower charges consumers a relatively low fixed fee for new connections, which cover our immediate costs of connection. This fixed fee is most often met by the property developers when a subdivision is created (residential/commercial/industrial) prior to electricity consumers becoming involved. MainPower avoids charging consumers for modifying a connection or decommissioning a connection.

3.5.4 Commonly encountered delays and potential timeframes for different connections

Some of the common issues encountered that result in delays to new connections can be summarised as follows:-

- Where the distribution network must be extended to the prospective consumer's property boundary, timeframes vary greatly depending on the location, size, and complexity of the new power supply build. In these situations, the subsequent new connection process cannot be started until the network extension process has been completed.
- Lack of familiarity with connection process.
- Many parties are involved with the new connection process, which creates complexity and opportunities for any party to miss a step.
- Knowledge about the new connection process, including the number of industry participants (e.g. distributor, retailer, MEP), and the elapsed time required to complete a new connection.
- The livening agent and the MEP are not necessarily the same organisation, which can complicate the scheduling of new connection and livening activities.
- DG being connected without following the complete process and involving the network, resulting in delays to certain aspects of the process or connecting unapproved DG equipment.

New offtake connections typically take a minimum of 15 working days' notice to process from beginning to completion, across all parties.

DG connection applications are processed in accordance with the timeframes required by Part 6 of the Electricity Industry Participation Code. Typically, it depends on the size and complexity of the application, some take considerably longer. The time the DG installer requires to complete their aspects of the work varies, including providing the necessary compliance paperwork, which may arrive up to 20 days after the work is completed.

3.6 Notice of planned and unplanned interruptions

MainPower notifies planned service interruptions by sending an electronic file using the Electricity Information Exchange Protocol 5A (EIEP5A) format to energy retailers of planned service interruptions with at least 11 days' notice, who in turn advise the affected consumers. We also advise consumers who have an active New Zealand mobile phone number using Short Messaging Service (SMS) text communications. These are sent at the time the EIEP5A communication is sent, and again 24 hours before the planned service interruption is scheduled to begin. In situations where these normal processes are not viable, such as short notice outages, we usually email customers directly using their registered contact email and telephone any who do not provide any email address through their energy retailer. We do this at least 48 hours before the outage, in accordance with our Connection Agreement.

MainPower provides notice of unplanned service interruptions, after the fact in most cases, by providing information and a detailed map on our website for consumers to access. In special cases or for consumers with greater reliance on electricity, we occasionally communicate directly using email or phone calls to the affected consumers. In unique cases, such as a national energy or power shortage, we also use social media channels and radio for rapid message distribution. If we have adequate advance warning of the unplanned service interruption, which is not common, we may also follow the short notice outage process outlined in the paragraph above. We are delivering a project to provide SMS in the event of unplanned service interruptions in winter 2024.

3.7 Performance indicators

3.7.1 Reliability

MainPower's network reliability is measured by the frequency and duration of interruptions to consumers' electricity supply. Our reliability targets guide our investment decisions, with the aim of meeting both our consumers' expectations and the regulatory requirements.

MainPower's key network reliability measures are applied as determined by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, and include:

- **SAIFI**, which measures the average number of supply interruptions for each consumer during the year
- **SAIDI**, which measures the average minutes that a consumer is without power during the year.

These SAIDI and SAIFI measures include planned and unplanned interruptions with a duration longer than one minute on MainPower's sub-transmission and high-voltage networks. MainPower's consumers view network reliability as a top priority, and the surveys show that they are generally satisfied with the current level of reliability.

3.7.2 Voltage quality

When an unplanned network interruption occurs, we target commencing the restoration of supply within three hours, deploying our Network Operations and Field Services teams, who are available around the clock. Our Network Field Operators are based throughout the region, and we hold spares of strategic parts in our depots to reduce repair times.

3.7.2.1 Monitoring voltage quality on the low-voltage network

MainPower currently utilises a few methods to monitor voltage quality on the low-voltage network. Transformer monitors are used across the network to monitor low-voltage bus voltages and end-of-line voltages. We are further exploring low-voltage analytics tools based on smart meter data to better understand and monitor the capability of the low-voltage network. Product and data acquisition trials have been running over the past year and continue into FY24 to inform MainPower's longer-term low-voltage network strategy. We have a robust customer complaints process that begins further investigation where issues are identified.

MainPower is in talks with the meter providers to obtain smart meter data. The ability to access and use this data will be cost dependent.

3.7.2.2 Work on the low-voltage network to address known non-compliance

MainPower deals with known non-compliance on the low voltage network through the annual maintenance and replacement program. Reports of low voltage network non-compliance are recorded in the works management system and remediated via the maintenance program.

3.7.2.3 Responding to reports on voltage quality issues

MainPower actively monitors customer complaints. When an issue is reported, a Power Quality Analysis procedure is started. A Field Operator will visit the location to assess the network assets in the area and perform spot measurements and tests. If this is inconclusive, MainPower will install a logger at the ICP in question and observe the power quality data for any signs of issue that relate to the reported problem. Additionally, the smart meter data will be interrogated where available. From this data, MainPower can determine what is occurring and provide advice to the customer or a solution where appropriate. All complaints are logged in MainPower's CRM so they can be referred to for any future queries or ongoing issues.

3.7.2.4 Communicating with affected consumers regarding voltage quality issues

MainPower engages with any impacted customers as they raise concerns and communicates whenever work is required to mitigate an issue. This can include notification of a required outage, consultation around design solutions or ongoing communication about identifying any issues and underlying causes as an investigation proceeds.

3.7.2.5 Plans for improvement

MainPower is actively seeking access to power data from ICP smart meters. This will allow better visibility of the low-voltage network to identify problem areas and allow MainPower to focus reinforcement spending on rectifying these issues. Additionally, accurate load information from ICPs will better inform planning and design practices to ensure issues are found early and fixed. This requires access to smart meter data from meter providers at a reasonable cost.

3.7.3 Network restoration

When an unplanned network interruption occurs, MainPower targets a commencement of restoration to the supply within three hours. Our network operations and field teams have on-call staff available around the clock to respond to unplanned interruptions. Our field operations are based strategically throughout our region. With depots in Rangiora, Culverden and Kaikōura holding a variety of spare equipment to reduce response and repair times.

3.7.4 Resilience

Resilience involves the ability of MainPower and our network to anticipate, absorb and recover from disruptive and extreme events such as snowstorms and earthquakes. A resilient network minimises the number of consumers impacted by significant events. We recognise the need to balance the cost of installing backup and redundant systems with providing a reasonable level of service that has the capacity to recover rapidly from extreme events. We are exploring ways to better manage MainPower's network and business resilience in line with industry guidelines.

MainPower has invested in an ADMS to help provide better visibility and control of our network. We also see an opportunity to improve both network restoration and resilience performance further through improved network architecture aligned with our Security of Supply Standard (see Section 6.3 of this document) and enhanced remote sensing and switching capability throughout the network.

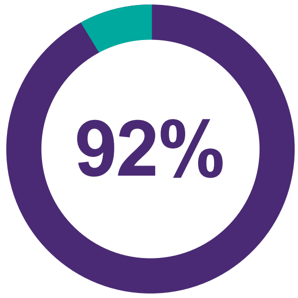
3.4.4 Health, safety and the environment

Our teams are committed to providing a safe network and healthy working environment across all our assets. MainPower promotes public safety around electricity throughout our region to help make sure our community is aware of our assets and activities. We take all practical steps to minimise risk and harm to the public, our people and our service providers, and we measure this in terms of the:

- Safety of employees and service providers
- Safety of the public.

Our objectives are to:

- Identify, manage and communicate risks associated with the workplace, the electricity distribution network and our business activities
- To ensure compliance with legislative requirements and industry standards
- To ensure that employees and field service providers have an appropriate level of training, skill and knowledge to carry out their work safely
- Provide safe equipment, plant and systems to ensure public and worker safety.



AWARENESS OF SAFETY MESSAGING

(90% in 2020)
(92% in 2019)
(92% in 2018)

We regularly monitor, review and report on our legal compliance obligations and risks. The main focus of this monitoring and reporting is to understand the compliance risks. Additionally, as part of the requirements for certification to ISO 9001, ISO 14001 and AS/NZS 4801, we must be able to demonstrate how we manage our legal requirements.

We design, construct, commission, operate and maintain the electricity distribution network and other company assets to ensure that they are safe, fit for purpose and do not pose a risk to health. We also participate in industry-related benchmarking of safety incidents to provide a basis for measuring our performance.

MainPower is committed to protecting and improving our environment, and we recognise our responsibility to strive for environmental sustainability. In addition to our business environmental sustainability drivers, our current network environment measures include the following.

- **Sulphur hexafluoride (SF6) gas:** This gas is used as an interruption medium in switchgear, and the Ministry for the Environment has set a compliance level of less than 1% annual loss, based on the total volume of gas on the network. MainPower is committed to minimising SF6 emissions, and we monitor and report on losses.
- **Oil spills:** Some assets on our network use oil as an insulating medium. We use a range of containment and mitigation solutions to prevent, or minimise the impact of, spills. Our annual target is zero uncontained oil spills across our network.

3.4.5 Physical and financial

It is important that MainPower continually assesses our asset management maturity against the requirements of the business and whether we are tracking to achieve the required maturity level. We also review overall organisational financial indicators and how we have performed in delivering the work programme. In addition, MainPower assesses performance against industry peers to ensure we are aligned with the industry using industry benchmarking.

All this is achieved through our processes for:

- Maintenance programme delivery
- Capital programme delivery
- Asset management maturity (using the Commerce Commission's AMMAT)
- Financial performance
- Industry benchmarking.

3.8 Performance indicators and targets

Performance targets for the 10-year planning period are shown in Table 3.4.

Service Measures and Targets														
Service Class	Performance Indicator	Performance Measure	Past Performance Targets		Future Performance Targets									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Reliability	SAIDI – System Average Interruption Duration Index *	Average minutes of supply lost per customer per year	280	272	265	257	250	243	236	230	224	218	213	208
	SAIFI – System Average Interruption Frequency Index *	Average number of times a customer's supply is interrupted per annum	2.04	1.98	2.01	1.96	1.90	1.85	1.80	1.75	1.71	1.67	1.63	1.59
	Feed reliability	None – forward indicator only												
	Unplanned interruptions restored within 3 hours	% of unplanned interruptions where the last customer was restored in less than 3 hours	No targets set (new)	80%	80%									
Health, Safety, Environment and Quality	Safety of workers	No safety critical injuries	None		None									
	Safety of public	No injuries to members of the public	None		None									
	SF6 gas lost	Gas lost as % of total gas volume	< 1%		< 1%									
	Oil spills	Uncontained oil spills	None		None									
Consumer Oriented	Engagement effort	Customer Pulse Survey Score, from 1 (very dissatisfied) to 5 (very satisfied)	> 2.5		> 3.5									
	Staff friendliness		> 4		> 4									
	Quality of work		> 4		> 3.8									
	Timeliness of service		> 3.5		> 3.8									
	Communication		> 3.5		> 3.8									
	Staff reliability		> 4		> 3.8									
	Final price		> 4		> 3.5									
Physical and Financial	Maintenance delivery	Maintenance programme delivery by budget	> 90%		> 90%									
	Capital delivery	Capital programme delivered by budget	> 90%		> 90%									
	AMMAT	Complete workstreams noted in AMMAT	> 90%		> 90%									
	Industry benchmarking	Assess ourselves against: · operating expenditure per ICP · capital expenditure per ICP · quality of supply (SAIDI and SAIFI) · non-network operating expenditure per ICP	< 75th percentile		< 75th percentile									

Table 3.4: MainPower's performance indicators and targets

**'Future performance targets' in this table are normalised. The Electricity Distribution Information Disclosure Determination is changing in 2025 and future AMP figures may be non-normalised.*

3.9 Performance evaluation

3.9.1 Network reliability

Our network reliability is measured using SAIDI and SAIFI indices averaged across the entire network (see Figure 3.). This provides us with the outage duration (time) and the number of outages that the "average" customer experiences. We analyse our network's quality of supply by causes, asset categories and feeder reliability, which helps to inform forward network-related projects and internal workstream improvements.

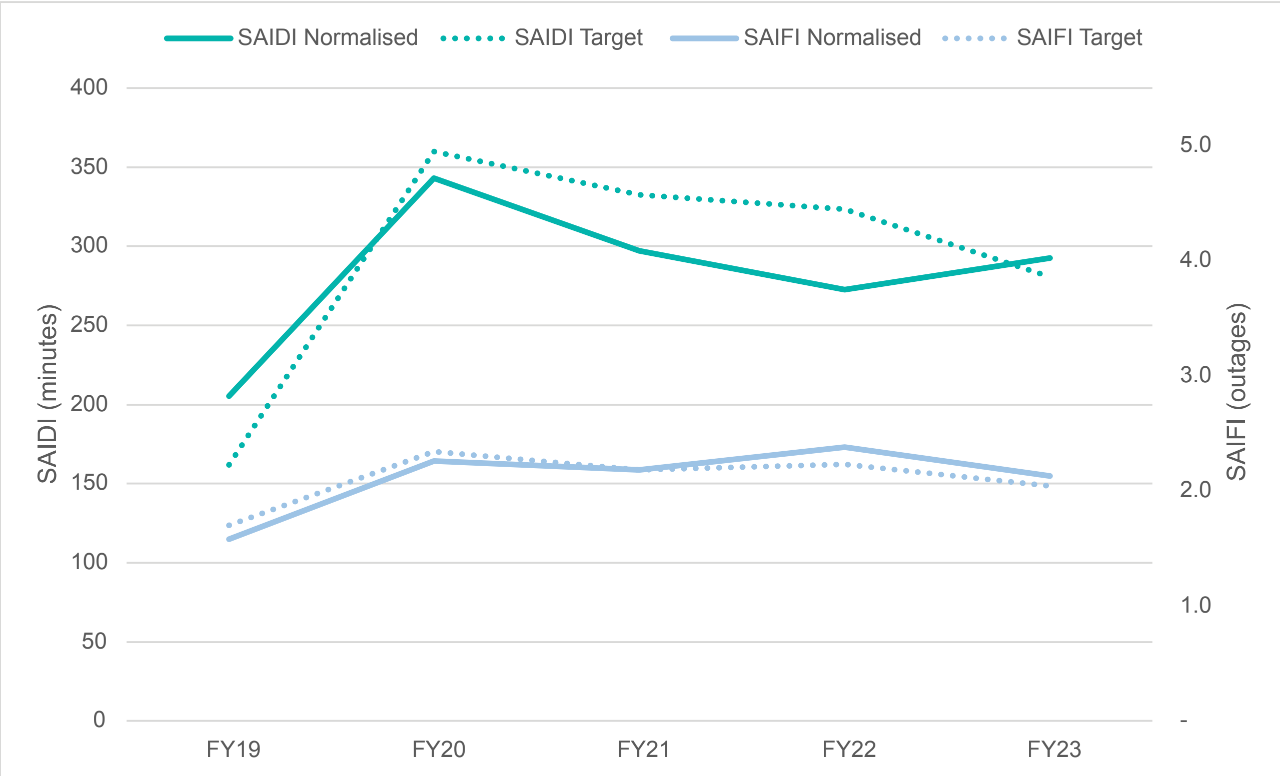


Figure 3.8: MainPower's network reliability SAIDI and SAIFI over 5 years (FY19–FY23)

MainPower's consumers view network reliability as a top priority and are generally satisfied with their current level of reliability. Examination of network performance over a five-year period indicates a step change in MainPower's network performance that has resulted in the occurrence of more outages, and with longer duration, than might have been expected from historical performance. To understand this trend, it is helpful to break down reliability into planned and unplanned events (see Figure 3.9 and Figure 3.10).

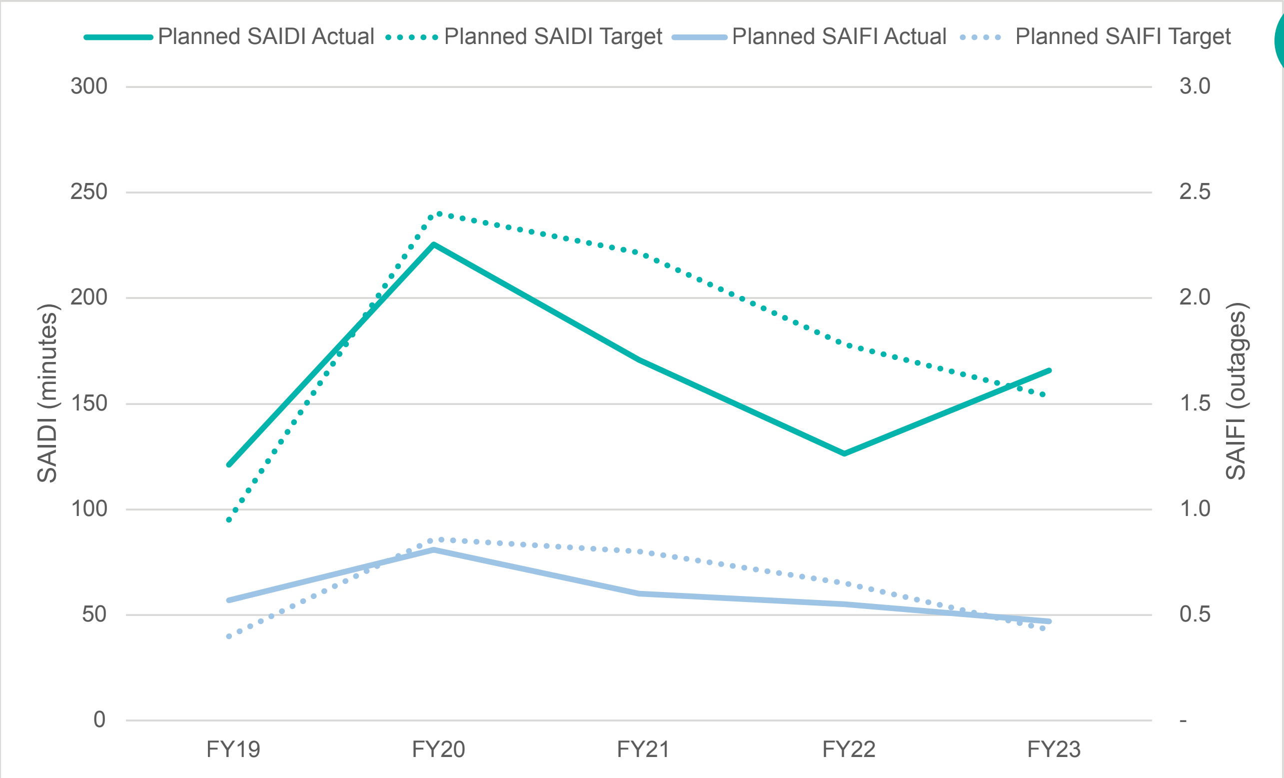


Figure 3.9: Network reliability – planned (FY19–FY23)

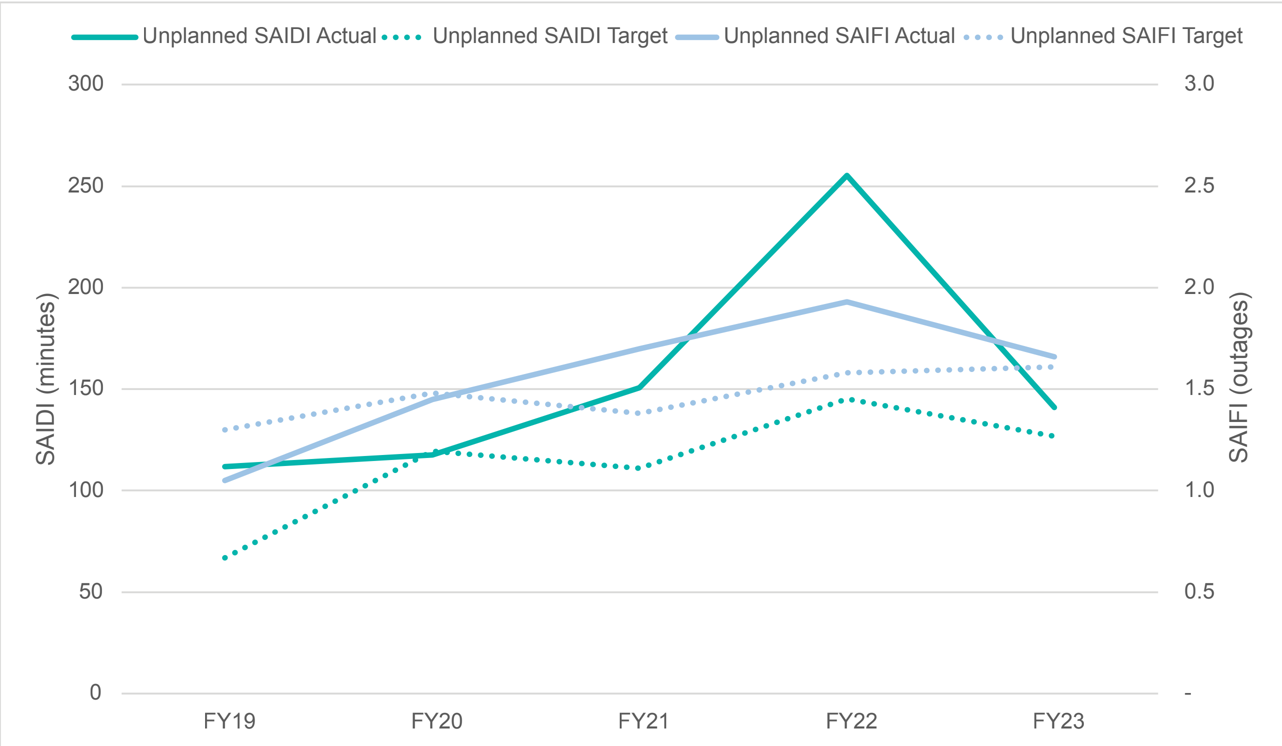


Figure 3.10: Network reliability – unplanned (FY19–FY23)

Figure 3. and Figure 3. show a reducing trend in planned outages in the last three years, and an increasing trend in unplanned outages. This shift in planned performance was brought about by improving work practices in line with the long-term asset management objectives. Actual outage duration and frequency for planned work was better than forecast in three of the four years, and in line with plan in the last reporting year. Fifty-seven percent of MainPower's FY23 Normalised SAIDI was attributable to planned works, reflecting our risk-targeted renewals programme and network architecture. Our network architecture is based on a rural, radial configuration with limited ability to supply consumers via alternative sources, which increases the impacts of unplanned outages.

The most significant drivers of unplanned reliability performance in FY23 were related to adverse weather events, followed by equipment failure and vegetation-related events. Unanticipated equipment or system failure events are fed into MainPower's asset management programme and analysed for improvement(s) to long-term asset management strategies. To better understand what contributes to unplanned electricity distribution network reliability, we analyse all outage data by cause, using outage statistics over time to reveal any underlying trends. We use a five-year rolling average across all outage categories (see Figure 3.). MainPower expects adverse weather events to increase in the future because of climate change. This is likely to also have an impact on "cause unknown" events, where high winds or debris can impact our predominantly rural network without leaving behind any obvious signs of interference.

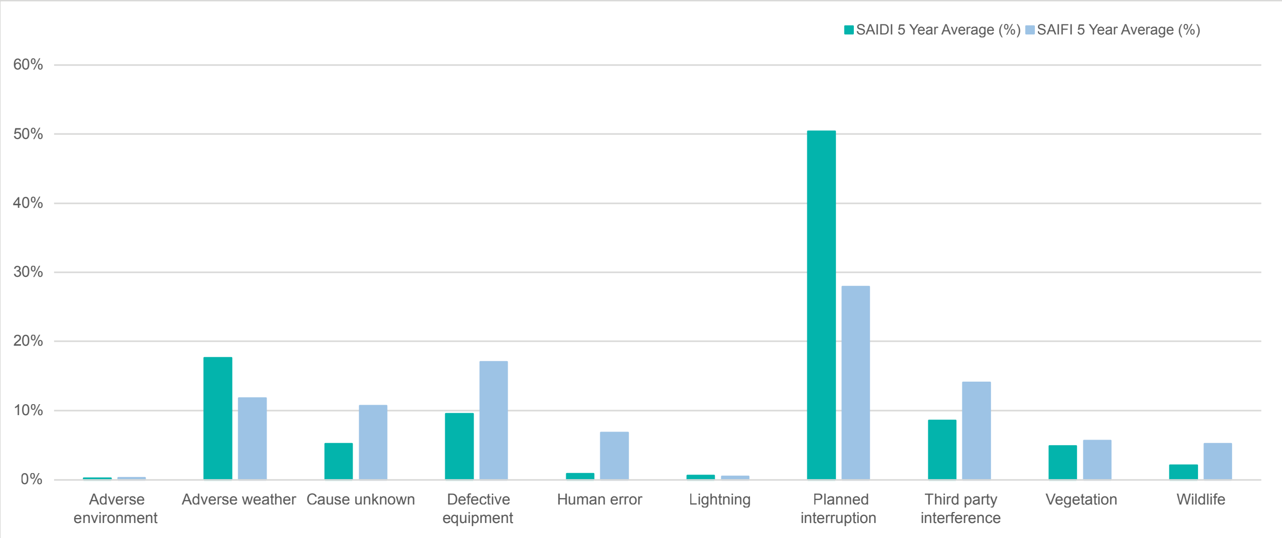


Figure 3.11: Network reliability, by cause (5-year rolling average, FY19–FY23)

While this analysis provides useful data on the overall contributors to deteriorating network performance, we know that trends can be affected by single events. Therefore, MainPower reviews the outages, by cause, over time. The results of this for FY19 to FY23 are shown in Figure 3.12 and Figure 3.13.

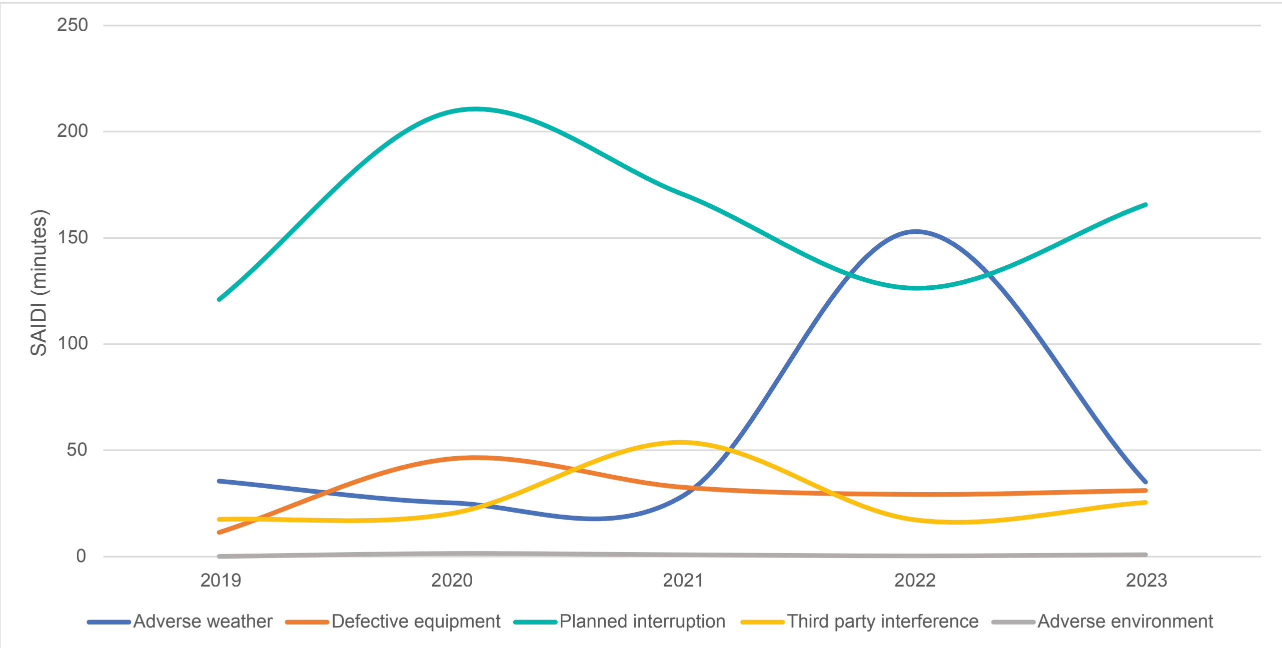


Figure 3-12: Network SAIDI, by cause (FY19–FY23)

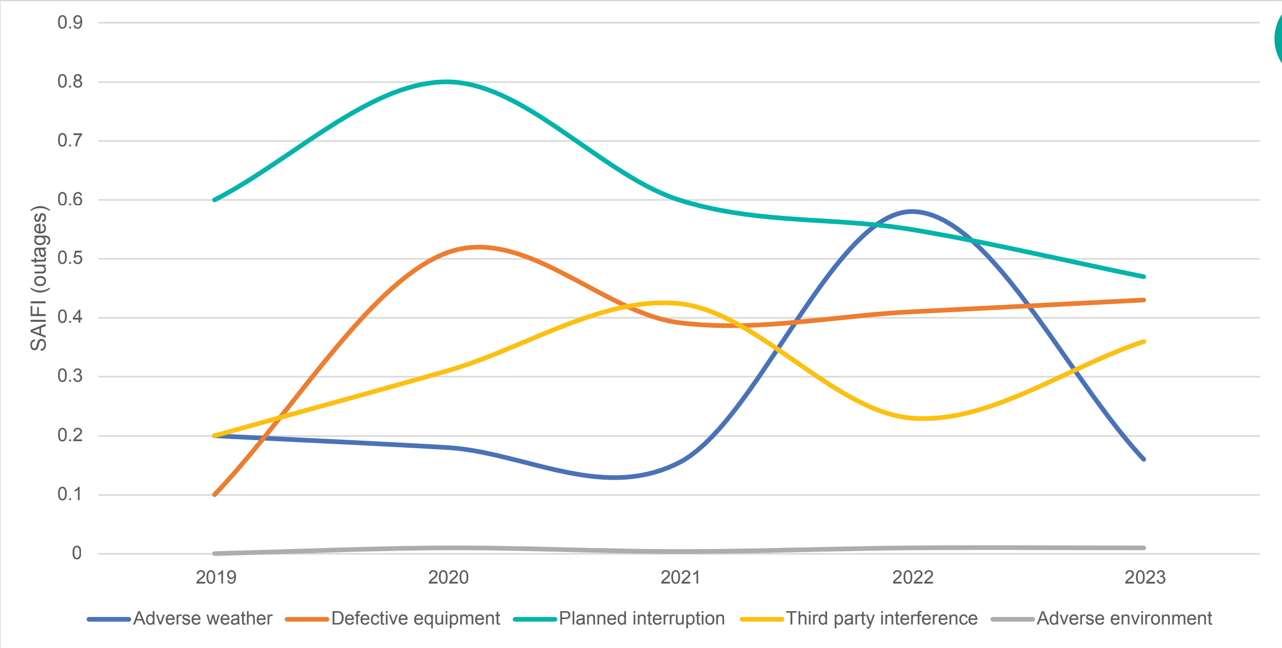


Figure 3.13: Network SAIFI, by cause (FY19–FY23)

The "adverse weather" category was impacted by a single significant event in September 2022.

It is important to include the real impact of outages on our network in the analysis to ensure root causes can be discovered and solutions implemented. Table 3.5 identifies the top contributors to outage duration (SAIDI) and outage frequency (SAIFI) over the 5-year period FY19 to FY23, in order of contribution.

Outage duration (SAIDI)	Outage frequency (SAIFI)
Adverse weather	Defective equipment
Defective equipment	Third-party interference
Third-party interference	Adverse weather
Cause unknown	Cause unknown
Vegetation	Human error
Wildlife	Vegetation
Human error	Wildlife
Lightning	Lightning

Table 3.5: A high-level analysis of the outages, by cause

The following Table 3.6 summarises the initiatives to improve network reliability.

Category	Analysis	Initiatives	Update	Target Date
Planned Works	MainPower has augmented its planned works programme to target fleet renewal and to improve network resilience. Additional outages are required to implement these improvements because of the radial nature of the network.	Implement a company-wide discussion and working group to identify continued areas of improvement for the approach to planned work.	Previous initiatives during the last three years have been effective at limiting the impact on the reliability of MainPower's total work programme. New initiatives are expected to improve on this foundation.	FY25-FY26
Defective Equipment	Reviewing defective equipment by asset class indicates that reliability is adversely affected by: • switchgear • ring main units (RMUs) • cable faults • insulators.	Work programme: 1. Upgrade programme for the Amberley, Hanmer and Hawarden zone substations within AMP period. 2. RMU replacement programme 3. Insulator and crossarm inspection programme 4. LiDAR1 aerial inspection pole maintenance programme 5. Line-tightening programme	• RMU replacement programme progressing. • Insulator and crossarm inspection programme underway. • Aerial inspection programme complete with forward annual programme underway. • CBRM models partially in use and under further development across other assets fleets.	FY25–FY26
Adverse Weather	Adverse weather events are increasing in frequency and rural radial feeders are exposed to windblown interference during storms.	LiDAR aerial survey to assist in identifying potential risks from vegetation, line clashes and latent pole-top failures to proactively inform the overhead distribution line maintenance programme.	Taking advantage of the ADMS roll-out for early identification of location and potential cause of outages, and for better management of repair activities during weather events.	FY25–FY27
Third-Party Interference	MainPower has a public advertising campaign to communicate the need to watch out for overhead lines. We also issue "High Load" and "Close" approach permits, including action plans where evidence suggests the terms and conditions under which the permit is issued can be ignored. Additionally, customers have 24-hour access to underground cable locations information via the online "beforeUdig" service.	Active watch: MainPower intends to monitor third-party interference and determine whether additional steps need to be implemented.	Third-party interference impacts have begun to decline. MainPower will continue the awareness campaign to ensure the trend continues in this direction.	FY25

[1] LiDAR (Light Detection and Ranging) is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances).

Table 3.6: Network reliability improvement summary

3.9.2 Feeder reliability

In addition to system-wide interruption cause analysis, we review our network reliability trends over five years at a distribution-feeder level. This helps us understand where parts of our network might be experiencing interruption frequency or duration that is higher than average. The graphs in Figure 3.14 and Figure 3.15 show that in the years FY19–FY23, the impact on reliability from the top five worst-performing feeders had started to decrease (see details in Table 3.7).

Figure 3.14: Top 10 feeders with highest cumulative unplanned SAIDI (FY19–FY23 average)

Figure 3.15: Top 10 feeders with highest cumulative unplanned SAIFI (FY19–FY23 average)

Feeder	Analysis	Initiatives	Target Date
S13 West	This feeder supplies southern Rangiora and Waikuku township from our Southbrook Zone Substation. Investigation into the feeder found it had urban and commercial loads that were being affected by interruptions mainly on the large overhead rural sections of the feeder. These interruptions mainly consisted of third-party interference (vehicle contact with assets) and defective equipment, resulting in a large outage area because of the size of the feeder with minimal downstream protection and isolation.	The undergrounding of part of this feeder, performing switching alterations to the feeder configuration to minimise single-interruption impact, and replacing the feeder protection equipment as part of our Southbrook Zone Substation rebuild. This was completed under the Southbrook 66 kV Substation Upgrade Major Project. Increasing the number of feeders out of this substation, and the areas they supply, will have a positive impact on reliability through reduced affected customer numbers for any given fault.	Completed as evidenced in reduction in unplanned SAIDI S13 five-year average feeder contribution.
H31	This feeder supplies the Hawarden township and the large rural area west of the township. The feeder is entirely rural overhead in construction. Investigations into the large SAIDI contribution found a large proportion of outages related to a windstorm in September 2022. The impact of this event was considerable across the network, especially in rural areas.	As the inclusion of this feeder in the high-impact list was largely related to a weather event that had a large impact on the entire network, the feeder will be monitored for ongoing contributions to SAIDI and SAIFI during weather events and action taken if the trend continues.	N/A
X54	This feeder supplies the Oxford township and a large amount of the surrounding rural area. This feeder is predominantly 11 kV rural overhead network. The September windstorm heavily impacted this feeder, along with a few incidents at the start of the feeder (including flooding and vehicle accidents) that impacted many customers.	Several projects in the 10-year plan will assist with alternative supplies for this feeder. They include feeder ties to other feeders supplied out of Swannanoa Zone Substation and Ashley GXP. It is expected these will minimise the impact of severe weather events on this part of the rural network.	FY32
SW66	This feeder supplies the West Eyreton region from our Swannanoa Zone Substation. This feeder is also a large rural overhead feeder that has experienced a high number of vegetation- and weather-related interruptions over the past five years. Although it is a rural feeder, this region is more densely populated than a typical rural feeder, and therefore interruptions have a higher impact, owing to the larger number of connections.	A project is underway to install an intermediate circuit breaker and reconfigure the feeder to minimise the number of customers affected by outages. We also aim to improve and target our vegetation management programme to prevent vegetation-related interruptions. Ongoing reliability of this feeder will be monitored to assess the effectiveness of the new configuration.	FY27 stage two completion
SW62	This is the main feeder supplying the rural area west of Rangiora. It is predominantly 11 kV rural overhead construction. Investigations into the feeder have revealed several outages with unidentified causes – the disproportionate number of vegetation- and lightning-related outages may be related to some of these unidentified causes.	Initiatives are currently underway to identify the root causes of a series of cause-unknown outages impacting this feeder. The separation of the feeder into smaller outage areas will also assist with identifying areas of concern and gathering information to identify root causes.	FY24-FY25

Table 3.7: Network feeder reliability improvement summary

3.9.3 Reliability analysis model

MainPower has been building a reliability analysis model to support the development of a more comprehensive understanding of our network reliability (see Figure 3.16). This tool allows analysis at an ICP level for both low-voltage and high-voltage outages, using data from our ADMS system.

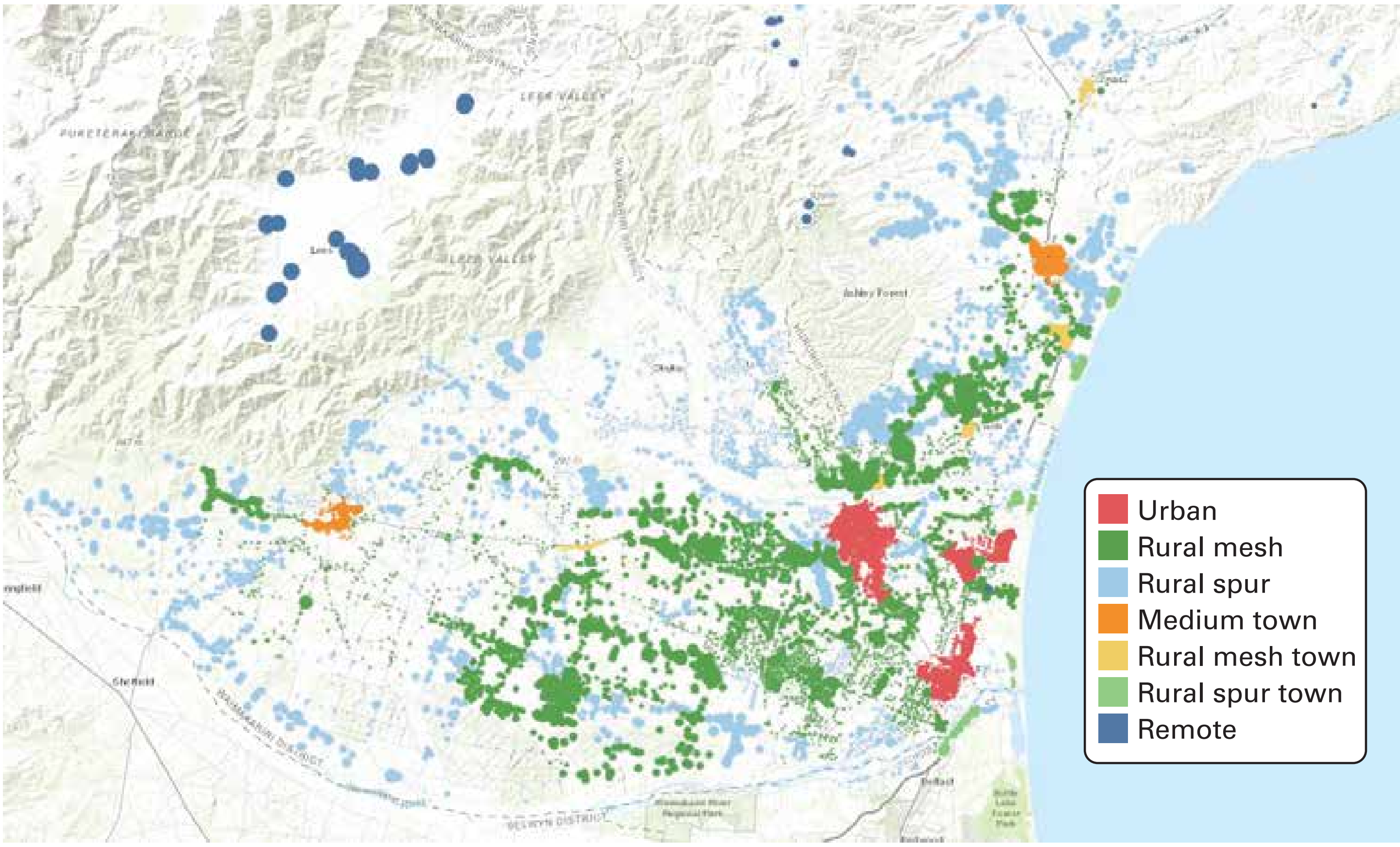


Figure 3.16: MainPower's reliability analysis model

In Figure 3.16 above, we have categorised ICPs using the customer classification shown in Figure 3.17 and geographical attributes to better understand and measure our network against expected levels of reliability. We see this as being a more customer-centric approach to reliability analysis, extending beyond aggregated feeder reliability levels. We intend to continue to develop this tool and use it to inform a more targeted approach to our investment in network reliability, alongside direct customer consultations.

This customer-centric approach to reliability should provide greater detail on the success of MainPower's operations through the eyes of our consumers. By stepping away from measurements based on system-wide averages and focusing on the impact to specific consumer groups and specific ICP locations, MainPower will be able to better understand if the expectations of our community and owners are being met.

It is well known that geographical area plays a significant role in the ability to supply power. Until now, the impact of this aspect on the reliability of power supplies in different geographical locations has largely been ignored through the SAIDI and SAIFI reporting as a system average. MainPower has now split consumers into groups based on their location in the network, which roughly translates to distance from a main supply. Figure 3.17 shows the approximate number of consumers in each group.

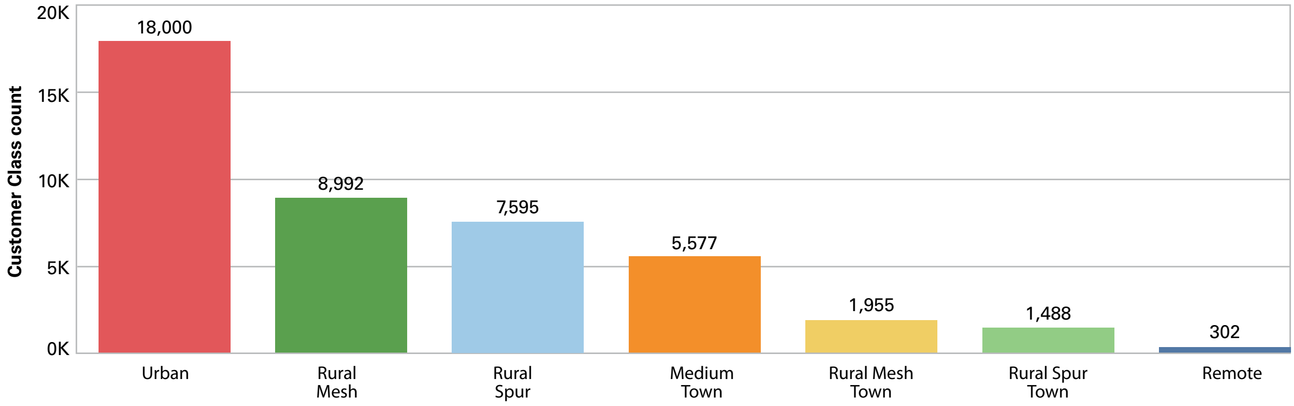


Figure 3.17: MainPower's connected consumers by classification group

One particular interest is the high number of connected ICPs at our urban centres such as Kaiapoi and Rangiora, and the low number of consumers connected in remote areas of the network. This breakdown of consumer groups can be used to show where the largest impact of network reinforcement and capital expenditure is likely to occur. The impact of outages on the MainPower network to each of these consumer groups is shown Figure 3.17. It should be noted that these figures are non-normalised and heavily impacted by large events, especially the remote consumers. With so few consumers in this group, a high result for a small number of consumers significantly lifts the average value.

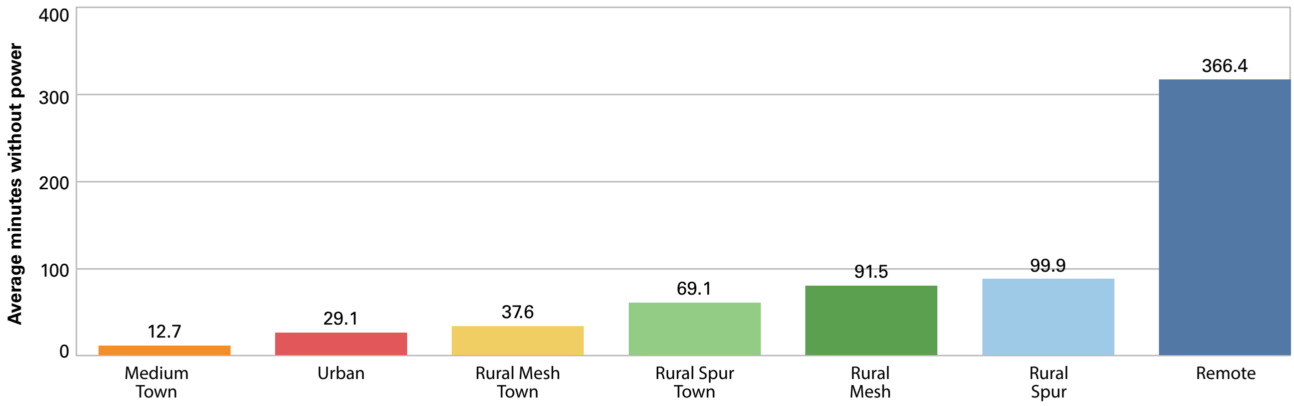


Figure 3.18: Average time spent without power for each classification group

The appearance of the graph in Figure 3.18 is an approximate inverse of the graph in Figure 3.17. This is due to the increased number of alternate supplies in denser areas, where the network naturally becomes meshed, and the increased number of consumers connected to these supplies that would be impacted by outages. This provides insight into where improvements can be found for both SAIDI and SAIFI, and where consumer engagement can be more targeted and relevant for the different consumer segments.

MainPower can assess both the network performance for specific groups against customer expectations and the network performance against the weighted average expectation. These comparisons can directly inform the long-term strategic goals and capital expenditure for reliability at MainPower.

The reliability dashboard also provides advantages to network planning and visibility, through the ability to view the network as individual ICPs geographically. This enables the planning team to examine outages in more depth than the previous "worst-performing feeder" analysis allowed. Figure 3 shows an example of the information display and the process.

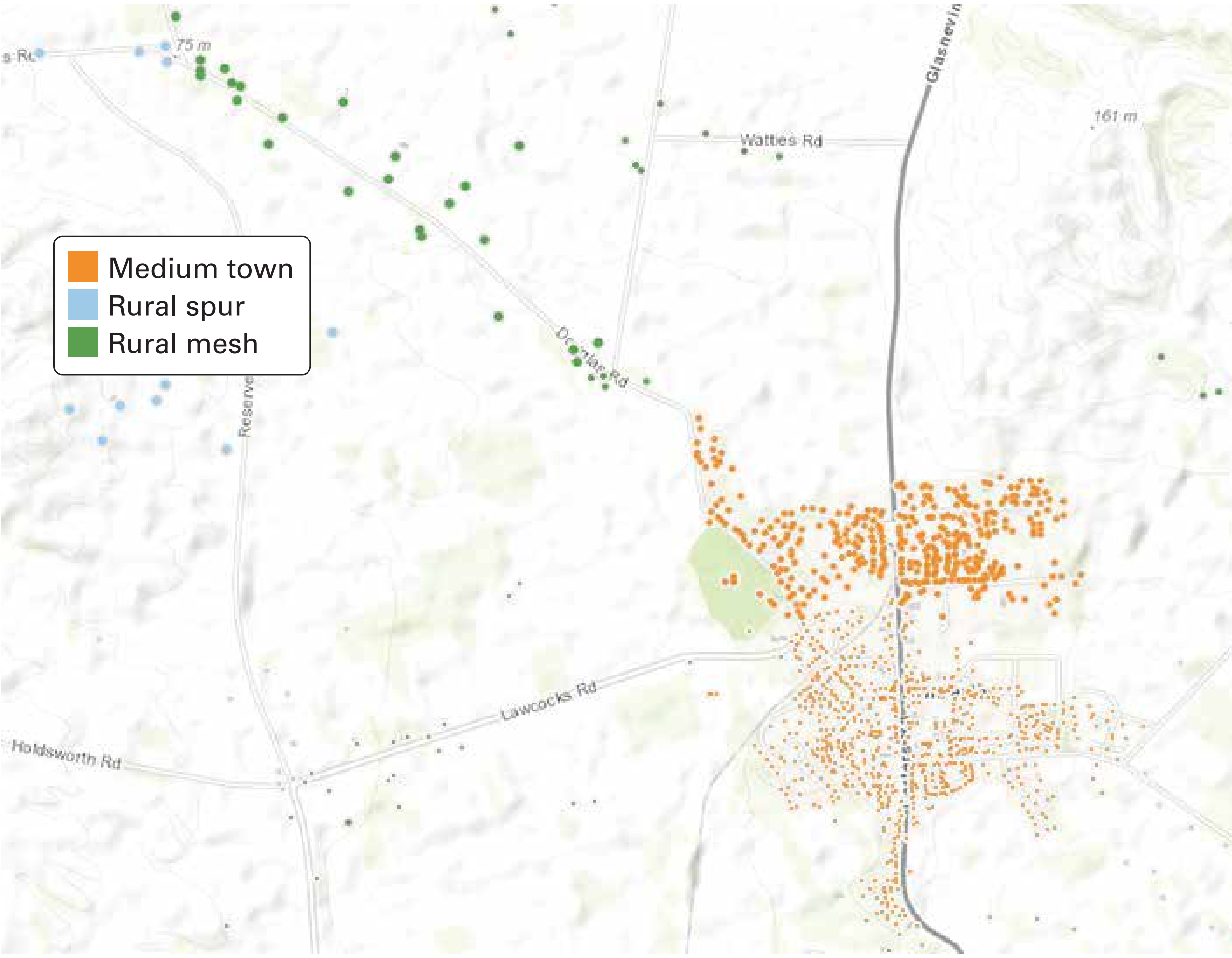


Figure 3.19: Example of ICPs coloured by classification group and sized by the total length of outages experienced

The various colours in Figure 3. show the different classifications of each ICP. In this case, the Amberley township is orange, representing the "medium town" category, and the areas outside Amberley are blue or green, representing "rural spur" and "rural mesh", respectively. The difference in performance between the northern part of Amberley and the southern part is obvious. This highlights an area of improvement for MainPower and indicates the importance of an alternative supply being made available to this part of the network. Additionally, the similar size of the dots in the rural areas and the town ICPs indicates that there may be some interaction whereby faults in rural parts of the network are resulting in outages for customers who are more urban. Again, this highlights an area that will benefit from further investigation and reinforcement. These issues have been resolved in this AMP work programme with identified projects resulting from these visualisations and analysis.

As shown above, taking a view of reliability that starts at the ICP and builds upwards to a system level, instead of looking back down from the system level, has significant benefits for the individual consumers and for MainPower's business through more targeted capital expenditure and better reliability outcomes.

3.9.4 Health, safety and the environment

We report all employee injury and public safety events through our Vault safety information management system (see Table 3.). In addition to employee and public safety monitoring, we have been process mapping our critical processes and identifying critical controls. MainPower also places significant emphasis on being an environmentally responsible company and complying with our responsibilities.

Personal Safety	FY23 Target	FY23 Actual
No safety critical injuries	0	0
No injuries to members of the public	0	0
SF6 loss (% to total gas volume)	< 1%	< 1%
Uncontained oil spills	0	0

Table 3.8: Health, safety, environment and quality evaluation (FY23)

3.9.5 Consumer oriented

Monitoring and improving service delivery is vital if we are to establish trust and goodwill with consumers and maintain our reputation with our stakeholders. While our customer satisfaction scores have continued to improve over time, we recognise that additional improvement is required in some areas. New baseline targets have been established in FY22 after redeveloping the survey to better align with the business' "Plan–Build–Operate" model (see Table 3.3 and Table 3.9).

Category	Analysis	Initiatives	Target Date
Engagement Effort	MainPower is aware that consumers interact with MainPower for different reasons and that the systems that support individual interactions are at varying stages of integration and maturity.	In 2021, MainPower moved to a "Plan–Build–Operate" model. This resulted in several changes to the teams delivering customer-initiated work. As these teams continue to settle into their new structures and processes, we expect to see further improvement in engagement effort scores. High demand for services is also putting pressure on existing resources.	FY24
Timeliness of Service	The respondents of this survey were only those who had engaged with MainPower regarding customer-initiated work. The results confirm the challenge faced when balancing work required to deliver the AMP alongside fluctuating customer-initiated works.	A business realignment was undertaken in FY21–FY22 to improve efficiency and communication internally between functions, to enable improved responsiveness to customers. However, the demand for these services is still high, impacting timeframes. As these teams continue to settle into their new structures and processes, we expect to see further improvement in timeliness and communication, particularly in relation to customer-initiated work.	FY24
Communication	Communication in this instance refers to communication regarding customer-initiated work. We recognise that with MainPower's high workload this year, there have been communication challenges.	The following initiatives are currently addressing this issue. • Process mapping of all existing processes and procedures related to customer-initiated work, and finding opportunities for improvement, is underway. • The Service Delivery Team is completing a CRM system development to align the system with their processes. • The Service Delivery Team has introduced service-level agreements to define appropriate timeframes for response to customers.	FY24
Staff Reliability	Customers indicate that MainPower staff are responding to their needs more consistently compared to FY21.	We believe that setting expectations early with customers (e.g. service-level agreements introduced with the Service Delivery Team for customer-initiated work) and keeping them informed about progress relating to their jobs on a timely basis will further support perceptions of reliability.	FY24
Final Price	MainPower recognises there is value in providing more consistent pricing to customers in relation to customer-initiated work. There is always a challenge when pricing customer-initiated work, as it is a payment that is not often associated with instant gratification, given the nature of our business. The COVID-19 pandemic and other external factors, including the war between Russia and Ukraine, have caused significant supply constraints and the cost of materials has increased. This has been reflected in MainPower's pricing rate cards.	MainPower reviews the pricing rate card regularly to ensure alignment with the current market. MainPower is also undertaking a review of our Network Extension, Upgrades and Capital Contributions Policy to ensure it is fair, sustainable and able to be consistently implemented.	FY24

Table 3.9: Customer rating of our performance measures and initiatives to improve them

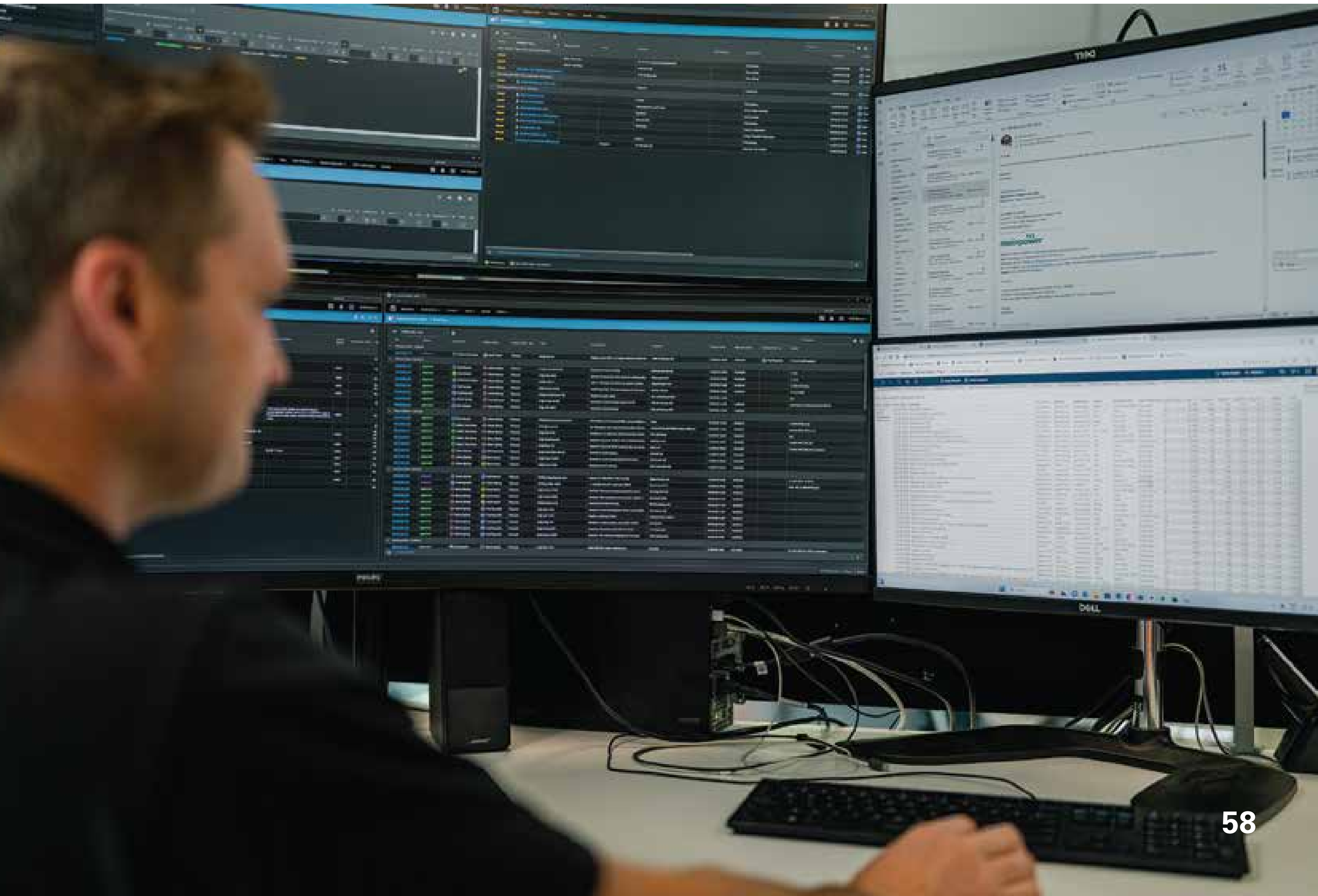
3.9.6 Physical and financial

3.9.6.1 Maintenance

MainPower has delivered on its safety critical maintenance throughout FY23. The works also included asset data collection, which enabled MainPower to assess overall asset portfolio health, as detailed in Section 7. Expenditure was within the performance target for the year (see Table 3).

Class	Description	Status	Update
Maintenance	Overhead inspections	Complete	N/A
	Zone substations	Complete	N/A
	Kiosks	Complete	N/A
	Transformers	Complete	N/A
	Switchgear	Complete	N/A
	Secondary systems	Complete	N/A
	Underground assets	Complete	N/A
	Network property	Complete	N/A
	Reactive	Complete	N/A

Table 3.10: Maintenance programme summary



3.9.6.2 Capital programme delivery

Capital expenditure finished above target for FY23 as MainPower has continued to deliver on the asset expenditure programme, which is informed by asset condition, criticality and the relevant security of supply standard (see Table 3.12). This work programme refinement will be reflected in elevated levels of capital expenditure in upcoming years.

Class	Description	Status	Update
Major Projects	Southbrook Substation Upgrade Stage 3	Complete	FY24
	Cheviot to Kaikōura Sub-transmission Line Upgrade	In progress	FY25-FY26
	Hanmer Subtransmission Upgrade	In progress	FY25-FY29
	Amberley Zone Substation 33 kV Upgrade	In progress	FY24–FY27
	Coldstream Zone Substation	In Progress	FY25-FY27
Reinforcement Projects	Amberley Reserve Road Link	Deferred	FY26
	Reinforce Swannanoa SW63 & SW66 Stage 2	In Progress	FY27
	Fernside Reconfiguration	In Progress	FY27
	Mandeville Area Voltage Improvements	In Progress	FY26
	Kaiapoi K7 Feeder Split	In Progress	FY25
	Kaiapoi Island Road Upgrade	In Progress	FY25
	Reinforce X52 Burnt Hill	Complete	
	Greta – Cheviot 22kV Link	Deferred	FY29
	Amberely Beach Alternative Supply	Deferred	FY29
Renewals	Overhead Assets, replace 710 units	Complete	100% complete*
	RMU, replace 10 units	In Progress	40% complete*
	Distribution Transformers, replace 29 units	In Progress	100% complete*
	Low-voltage link box, replace 10 units	In Progress	100% complete*
	Low-voltage switchgear units, replace 10 units	In Progress	50% complete*
	Service Boxes, replace 50 units	In Progress	84% complete*

Table 3.11: Capital programme summary (FY23)

3.9.6.3 Financial performance

The following Table 3.13 compares actual revenue and expenditure to the previous forecasts that were made for the FY23 disclosure year.

Expenditure on Assets	Forecast ($000)	Actual ($000)	% variance
Consumer connection	6,000	12,845	114%
System growth	3,246	1,692	(48%)
Asset replacement and renewal	11,575	10,668	(8%)
Asset relocations	–	–	–
Reliability, safety and environment:			
Quality of supply	1,152	236	(79%)
Legislative and regulatory	–	54	–
Other reliability, safety and environment	1,584	1,332	(16%)
Total reliability, safety and environment	**2,735**	**1,622**	**(41%)**
Expenditure on network assets	**23,556**	**26,826**	**14%**
Expenditure on non-network assets	3,359	2,631	(22%)
Expenditure on assets	**26,915**	**29,457**	**9%**
Operational Expenditure			
Service interruptions and emergencies	1,000	969	(3%)
Vegetation management	1,000	983	(2%)
Routine and corrective maintenance and inspection	4,361	4,083	(6%)
Asset replacement and renewal	–	2	–
Network operational expenditure	**6,361**	**6,037**	**(5%)**
System operations and network support	9,700	10,497	8%
Business support	4,200	4,341	3%
Non-network operational expenditure	**13,900**	**14,838**	**7%**
Operational expenditure	**20,261**	**20,875**	**3%**

Table 3.12: Financial performance FY23

Category	Analysis
Customer	Contestable in nature and above target, due to greater than expected demand for new connections.
Expenditure on Assets	Aligned with planned budget and planned units of replacement. System growth projects were delayed by constraints in project resources that delayed the detailed design work for major upgrade projects. Asset replacement and renewal expenditure was below budget, impacted by works to support strong consumer growth.
Operational Expenditure	Maintenance, both planned and reactive, was completed in the reporting year.

Table 3.13: Financial performance analysis

3.9.7 Industry benchmarking

The objective of benchmarking is to observe and understand how MainPower is performing as an organisation when compared with other EDBs. MainPower benchmarks itself against the seven network businesses listed in Table 3.15 based on ICP density (± 2.0).

Organisation	ICP/km	ICPs
Alpine Energy	7.7	33,269
Buller Electricity	7.3	4,757
Eastland Network	6.5	25,775
Horizon Energy	9.6	25,081
Network Waitaki	6.9	13,201
Marlborough Lines	7.8	26,630
MainPower NZ	8.3	43,131
Top Energy	8.1	33,263
Median	**7.7**	**26,203**

Table 3.14: Benchmark organisations (data from the Commerce Commission electricity distributers information disclosure data)

3.9.7.1 Network operating expenditure

MainPower's network operating expenditure, which includes planned and unplanned network maintenance and fault response, was lower than the peer group average during the 2022 financial year (see Figure 3.20). This reflected MainPower reviewing the asset management practices that were detailed in the last AMP. Expenditure is expected to increase to above the peer group average as MainPower implements its revised asset management practices.

Figure 3.20: Benchmarking – Network operating expenditure per ICP

3.9.7.2 Non-network operating expenditure

Non-network operating expenditure, which includes corporate, business support, asset management planning and network operation, is similar to the peer group average (see Figure 3.19). This reflects MainPower's focus on improving asset management maturity and the development of robust and effective business processes.

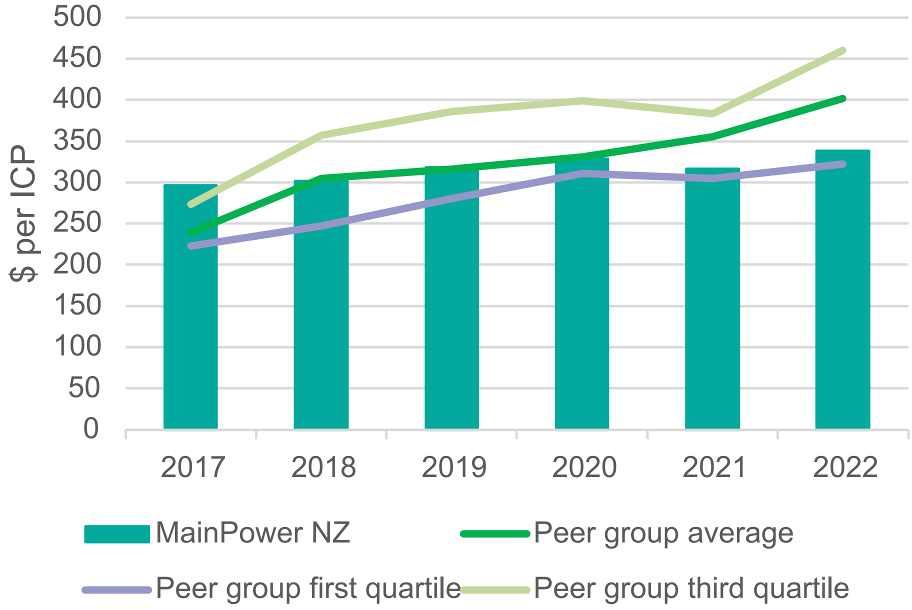


Figure 3.21: Benchmarking non-network operating expenditure per ICP

3.9.7.3 Capital expenditure on network assets

Capital expenditure is the cumulative expenditure required to deliver network requirements, including:

- capacity
- security of supply
- asset replacement and renewals.

MainPower's capital expenditure on network assets is influenced by the completion of a new zone substation project, and an increase in the number of consumer connection requests. This has resulted in third quartile capital expenditure per ICP performance (see Figure 3.22). Going forward, this is expected to remain at sustained levels owing to works required to deliver security of supply, network reliability, an increase in consumer connection requests and an increase in MainPower's replacement and renewals programme.

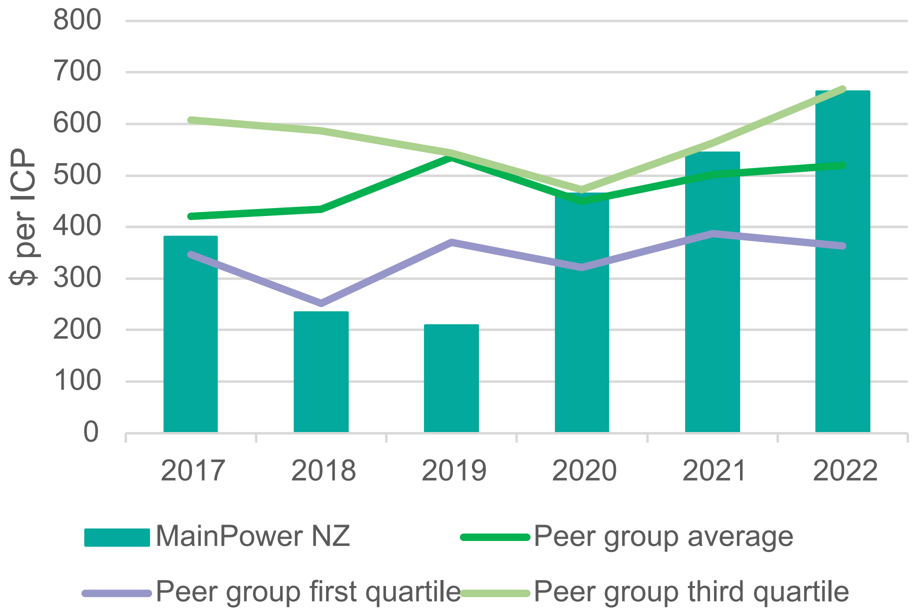


Figure 3.22: Benchmarking network capital expenditure per ICP

3.9.7.4 Reliability

MainPower's network reliability remains within the industry peer group average. However, forecast SAIFI and SAIDI is trending lower, with SAIFI at or about peer group average and SAIDI trending towards the 25th percentile of the peer group over the longer term (Figure 3.23 and Figure 3.24). Reliability initiatives have been identified to address quality of supply for MainPower in the future and return it to historical norms.

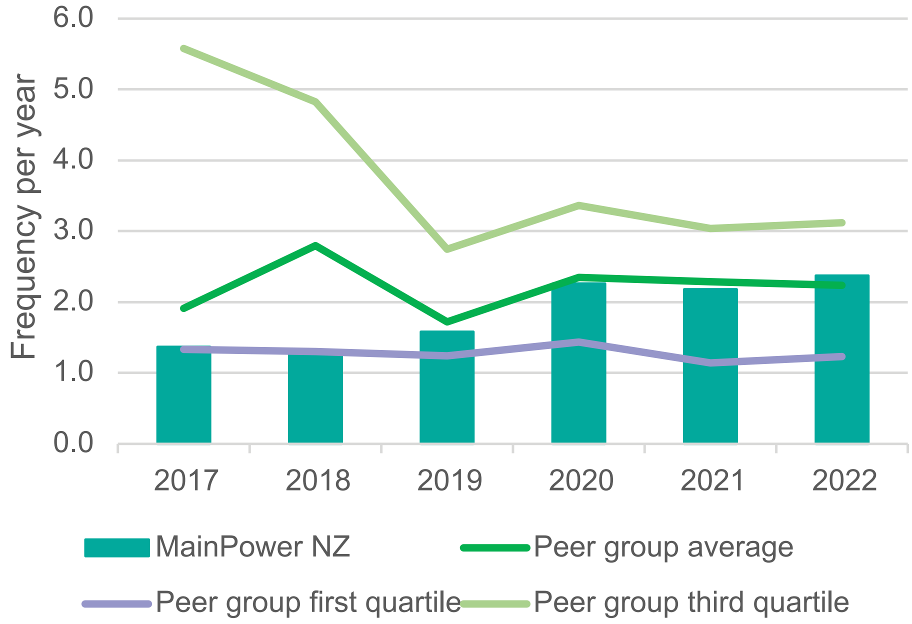


Figure 3.23: Normalised SAIFI benchmarking

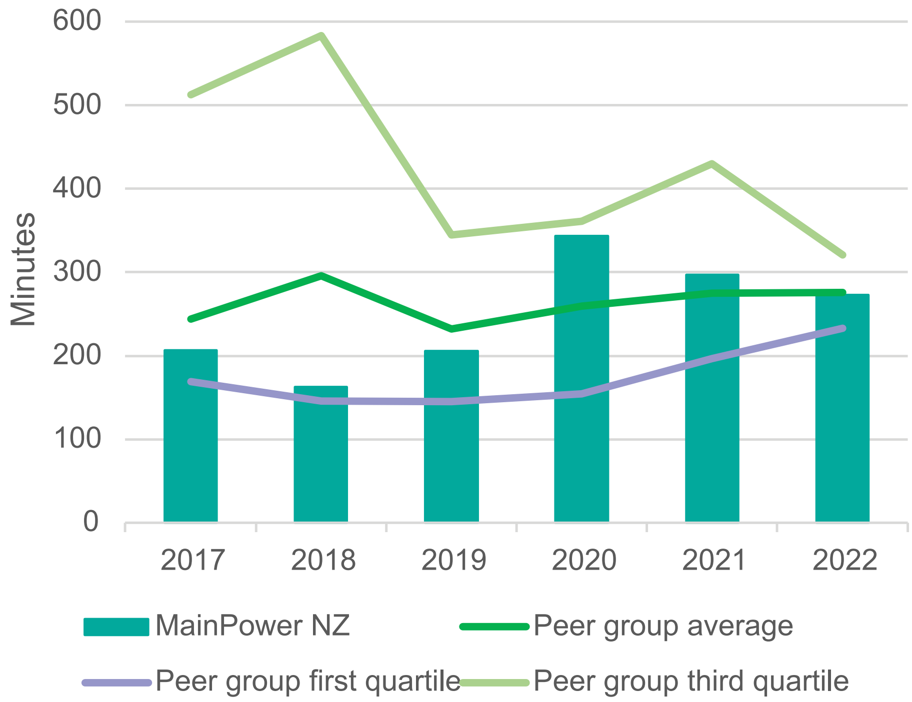


Figure 3.24: Normalised SAIDI benchmarking

3.10 Changes in forecast expenditure

A change in forecast expenditure that may materially affect performance definitions is not expected within the reporting year. Any instances where expenditure may affect network performance in the future will be reported and the internal response will be defined and implemented.

4. RISK AND THE ENVIRONMENT

4.1 Our approach to risk

Protecting the public, our team, our service providers, and the environment from the inherent risks posed by our electricity distribution network sits behind everything we do. Our Asset Risk Management programme is structured to incorporate these elements of public, personnel and environmental protection into a programme that ensures continuity of electricity supply, efficient protection of network assets, and protection of shareholder and commercial interests while ensuring that MainPower continues to meet its service-level targets.

MainPower recognises that risk management is an integral part of good governance and best management practice and has adopted the principles of risk management as detailed in AS/NZS ISO 31000:2018 Risk Management – Principles and Guidelines (see Figure 4.1).

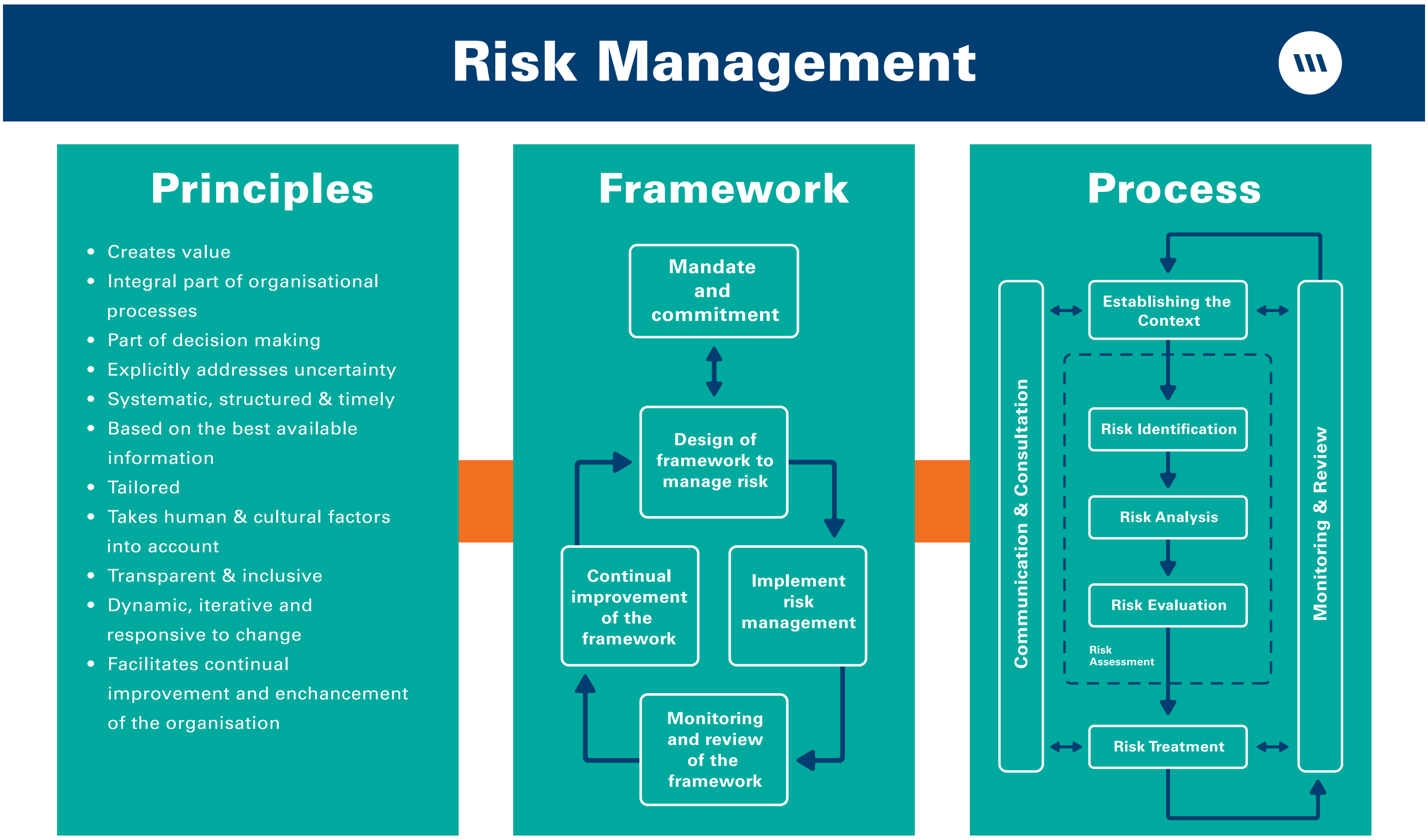


Figure 4.1: Risk Management Framework (drawn from ISO 31000:2018)

Asset risks are identified from asset management studies, risk registers, industry forums, incident analysis, audits, inspections, field observations, site-specific safety plans and safety observations, and are captured in an online platform that is used to manage and report on risks, criticality levels and control measures.

"Bow tie" diagrams are developed to visualise the risks and provide a means to qualify and communicate the control measures that manage each risk. Bow tie diagrams are also used to support investigating incidents, critical tasks and managing safety and business critical risks (see the next section).

A customised risk matrix is used to assess and quantify the likelihood and consequence of individual risks and define the auditing requirements and effectiveness of each of the control measures.

Compliance is assured through measured compliance reporting of critical control observations, carried out by all staff and captured in MainPower's online platform.

The Chief Executive has ultimate responsibility and accountability for ensuring that risk is managed across MainPower. The Chief Executive and Executive Team provide leadership, agree the strategic direction and risk appetite, and promote a health and safety-oriented culture to ensure the best outcome for MainPower, our people and the community.

The MainPower Board actively considers risks during strategic and tactical decision-making processes (as do all levels of management), as well as determining the level of residual risk appetite they are willing to accept.

A key priority of MainPower's Strategic Plan is to strengthen the links between critical risks, critical processes and incidents, focusing on prevention and reduction. Essential to this process is having a clear understanding of what our safety and business critical risks are, and providing assurance that controls are effective.

4.1.1 Critical risks

Critical risks are defined as anything that has the actual or potential to cause death to employees, contractors or members of the public; cause significant property damage; or cause MainPower to be severely impacted as a business.
MainPower has identified 10 safety critical risks and five business critical risks relevant to our business via a collaborative approach. Each risk has a risk control plan (bow tie) in place that is owned by a member of the Executive Team and is reviewed at least annually.

The bow tie methodology that MainPower uses for risk management offers an excellent visual tool for illustrating risk, providing a direct link between controls and management systems, highlighting areas where controls are weak, assisting with incident investigation and ensuring critical controls do not "fall through the cracks".

Figure 4.2: MainPower's critical risks

4.2 Environment and sustainability

MainPower takes an integrated approach to managing, delivering, and continually improving the environmental aspects of our business activities, services and products.

Using the United Nations Sustainable Goals as a foundation, we have identified three key areas where we believe we can make the most difference: prosperity, people and planet. These strategic areas form the basis of our Sustainability Management Plan.

MainPower is committed to:

- reducing waste
- using reusable and refillable products
- rethinking how we do things (changing to more sustainable products)
- using a greener supply chain (through prequalification)
- enabling electrification (low-voltage monitoring)
- supporting renewable energy (hydro, wind and solar)
- prioritising energy efficiency (LEDs etc)
- engaging with our community
- supporting inclusion, diversity and equity
- reducing carbon emissions
- repurposing materials (e.g. cable drums and power poles).

Our sustainability strategy considers the energy trilemma of finding balance between energy reliability, affordability and sustainability and its impact on everyday lives. We plan to achieve this by:

- reviewing the implications for the speed and direction of energy transition
- enabling low-carbon energy to drive innovation, economic recovery, and positive image
- accelerating digitalisation opportunities in energy and the new challenges of resilience.

Figure 4.3: Environment and sustainability

4.3 Network risk assessment

MainPower considers network risk within its Asset Management and Network Planning Framework, including:

- high-impact low-probability (HILP) events
- physical risk to GXPs, zone substations, transmission and distribution systems
- meteorological hazards – storms, floods, snow, wind, and lightning and resulting wildfires
- national grid emergencies
- cybersecurity and terrorism
- pandemics.

MainPower has an ongoing initiative to assess the impact of HILP events and network resilience in coordination with local authorities across North Canterbury and Civil Defence Emergency Management (CDEM) agencies.

4.3.1 High-impact low-probability risks

MainPower uses the bow tie risk methodology to analyse and demonstrate causal relationships in high-risk scenarios, and to identify the assets at threat from HILP events, namely:

- 66 kV and 33 kV sub-transmission systems
- zone substations.

While the frequency of meteorological events such as wind, flood and snowstorms far exceeds that of earthquakes, it is the consequences of earthquakes that most threaten our assets. MainPower has examined the risk of earthquake in its bow tie studies and identified escalation measures and response plans to manage these situations.

The effects of climate change are being considered, and summary findings are detailed in Section 4.6. Sea level rise along the east coast is not expected to cause major disruption to the electricity network in the AMP planning period. Table 4.1 presents a high-level assessment of HILP events on the network.

	Risk																
Asset	**Hurricane/Windstorm**	**Snow**	**Lightning**	**Flooding**	**Storm surge (coastal)**	**Tsunami**	**Drought**	**Heatwave**	**Wildfire**	**Earthquake**	**Landslide**	**Volcanic Eruption**	**Geomagnetic storm**	**National grid failure**	**Terrorism**	**Cyber incident**	**Pandemic**
66kV & 33 kV Sub-Transmission System	M	H	L	M	L	L	L	I	H	H	H	L	I	M	H	H	L
Zone Substation	L	L	M	L	L	L	L	I	M	M	L	L	I	M	H	H	L

Note: L = low impact, M = medium impact, H = high impact, I = assessment in progress.

Table 4.1: Assessment of HILP risks

4.3.1.1 Sub-transmission systems

MainPower is reassessing the sub-transmission and distribution network for HILP events. This work is being undertaken in conjunction with CDEM agencies.

Natural hazards of flood, windstorm, electrical storm, snowstorm and tsunami to the sub-transmission and distribution system are considered in Table 4.2. The information was sourced from external publications such as the Canterbury Regional Council Natural Hazards in Canterbury report, which has been reviewed against network design criteria.

Hazard	Observations	Likelihood/Consequence
Flood	• The risk to overhead lines from flood hazard is limited, even in a 100-year flood event. • Damage is isolated, resulting from landslips and/or subsidence or damage to individual poles sited within the normal course of a river. • A 500-year flood event would result in extensive flooding of some urban areas and subsequent damage to ground-mounted distribution equipment.	Likelihood: Possible Consequences: Major
Windstorm	• Damage to overhead lines is routinely caused by high winds. • Historically, this has resulted in minor and isolated damage. • Our design criteria meet or exceed the requirements for a 50-year return period event, as set out in AS/NZS 7000:2016. • The most severe winds are winds from the north-west (these occurred in 1945, 1964, 1975, 1988 and 2013). • The peak wind speed of 193 km/h recorded in August 1975 exceeded the 100-year recurrence interval. • Average recorded wind speeds in Christchurch approach 45% of design speed on 54 days a year and 66% on 3 days a year. • Canterbury has recorded four significant tornado events in the last 25 years, none of them located in our distribution area.	Likelihood: Possible Consequences: Catastrophic
Electrical storm	• Most parts of Canterbury have few electrical storms. • Over the plains, fewer than five thunder days, on average, occur each year, with the highest frequencies occurring between September and March. • Near the Southern Alps, 20 thunder days, on average, occur each year, with the highest frequencies during April and May. • Zone substations, transformers and communications equipment are protected with lightning arrestors.	Likelihood: Moderate Consequences: Unlikely
Snowstorm	• Canterbury occasionally experiences weather events that deposit heavy, wet snow on overhead lines. • Higher inland areas can be subject to ice build-up with coincident wind loading, which places high loads on overhead infrastructure. • Isolated sections of overhead lines may be exposed to a risk of avalanche.	Likelihood: Unlikely Consequences: Major
Wildfire	• This can cause damage and destruction to the overhead network infrastructure. • Can cause particulate accumulation on power lines and insulators.	Likelihood: Rare Consequences: Catastrophic
Earthquake	• Liquefaction can cause equipment foundations to fail. • Power line foundations can fail, causing loss of supply. • Underground conductor failures can cause loss of supply. • Repairs can be hampered by access restrictions. • Stock resupply limitations can occur because of transport issues.	Likelihood: Unlikely Consequences: Catastrophic
Landslip	• Remote sections of sub-transmission networks may be exposed to landslip, causing loss of supply.	Likelihood: Unlikely Consequences: Major
Tsunami	• While the occurrence of a tsunami is uncertain, this hazard is a realistic possibility for Canterbury, particularly at the mouth of the Waimakariri and Ashley Rivers, at Leithfield Beach, Motunau, and at Kaikōura where the narrow continental shelf and presence of submarine canyons makes this area particularly susceptible, especially Goose Bay and Oaro. • Most overhead lines are not generally exposed to this hazard.	Likelihood: Rare Consequences: Minor

Table 4.2: Hazard identification for sub-transmission and distribution systems

4.3.1.2 Zone substations

We have developed natural hazard exposure limits for our zone substation assets, using a weighting factor for the strategic importance of individual sites. This weighting is based on asset value, peak load and the capability to switch load away from the substation. The two measures used to define risk factors and risk priorities are:

1. risk factor = probability (years recurrence) × consequence (% damage)
2. natural hazard exposure = risk factor × weighted strategic importance.

This assessment has identified earthquake hazards as the greatest risk to zone substations.

Flood hazards for zone substations are not rated as significant, owing to the location and/or the resilience of design of a substation in a 1-in-500-year flood event (i.e. the likelihood that a 500-year flood event will occur in any given year). Other meteorological hazards have comparatively high probabilities, but the consequences for these assets are generally moderate.

4.4 Resilience of the network

MainPower is taking part in a pilot programme to model network vulnerability to hazard events and climate change using nationally accepted impact assessment modelling tools. The outputs from this vulnerability assessment will inform MainPower's resilience planning and the Network Regional Plans.

Network resilience is supported by the following documents and plans.

- Asset Management Policy: This describes our commitment to:
  - asset management, setting out our commitment to complying with regulatory requirements and industry standards
  - our consumers
  - ensuring we are resourced to deliver on our asset management objectives.
- Risk Management Plans: We have developed risk bow ties for our critical risks and defined the escalation control measures to manage critical events and reduce their consequences.
- Incident Response Plans: These are aligned with New Zealand's Coordinated Incident Management System (CIMS), which is key resources for our response to major incidents or events.
- Participant Rolling Outage Plan: This sets out the actions that MainPower will take to reduce consumption in the event of an emergency being declared by the System Operator.
- Security of Supply Standard: This defines the level of service that is required of the network to meet normal demand under contingency events, such as equipment failure or serious incident.

4.5 Risk mitigation, practices and plans

4.5.1 Risk mitigation measures

Maintaining our network is a key priority and includes a scheduled programme of planned works, as well as a defect management programme.

MainPower is moving to a CBRM approach, based on the Electricity Engineers' Association (EEA) Asset Health Indicator Guide and Asset Criticality Guide, in combination with CBRM principles from the United Kingdom. This allows us to use condition data, attribute data and probability of failure to develop asset health ratings for our assets which, when combined with asset criticality, allows us to optimise asset portfolio investment and target our highest-risk assets.

4.5.2 Activity, plant and equipment risk

All critical activities required to operate and maintain the network – including plant and equipment – are risk assessed using bow tie methodology. These are living documents and are reviewed after events, where new risks have arisen or controls have been added or removed.

At MainPower, critical controls are deemed effective when they are:

- implemented (i.e. there is a process in place and people are trained)
- applicable to the hazard and independent (i.e. not reliant on other controls)
- reliable (i.e. function consistently)
- monitored and audited.

Risk controls are monitored through inspection programmes and "critical control observations", with key performance indicators set for people leaders and executive leaders across the business.

All critical risks are formally reviewed on an annual basis, in addition to ongoing incident and risk reviews.

4.5.3 Business continuity plan

Our Business Continuity Plan is incorporated into our Incident Management Plan (see the next section), which is designed to minimise disruption after a critical event. We have identified our critical business activities and processes, and the types of events that can interrupt them.

The plan has assessed critical risks arising from:

- disruption of electricity supply during a natural disaster
- disruption of electricity supply from a major supplier (e.g. Transpower)
- climate change impacts (e.g. rising sea level, extreme flooding, extreme change in temperature, significant weather events, wildfire)
- disrupted systems and shortage of staff during a pandemic
- legislative non-compliance
- risk of fire to our assets or work undertaken within the network area.

4.5.4 Using an Incident Management Plan to respond to disruptive incidents

The Incident Management Plan guides our response to any disruptive incident that has a serious impact on our people, operations, services and reputation. The plan outlines how we will strategically and operationally manage our response so that we can prevent or reduce the impact and can continue to deliver those functions and services that are critical to our business.

Part of our response has been to adopt an Incident Management Framework, which outlines how we respond to, and operate in, any disruptive incident. The framework is based on New Zealand's CIMS and covers the 5 Rs – Reduction, Readiness, Response, Recovery, Review (see Figure 4.4).

Simulations are practised at least twice per year, with additional training exercises facilitated across the Incident Management Team to increase competency.

Figure 4.4: New Zealand’s Coordinated Incident Management System: Five Rs

4.5.5 Liaising with Civil Defence Emergency Management agencies

As a “Lifeline Utility”, we are obliged under the law (including the Civil Defence Emergency Management Act 2002) to ensure we can continue to function, even potentially at a reduced level, during and after an emergency, and that we have plans available to ensure continued operation. We are also obliged to participate in developing the CDEM Strategy and CDEM Plans, and to provide technical advice to the Director and CDEM Groups as required.

As noted earlier, some of our recovery plans will activate once predetermined triggers are met.

4.5.6 Using insurance practices to minimise the impact from loss of, or damage to, our assets

We maintain an insurance programme with an objective to cost-effectively minimise the impact to MainPower from any loss of, or damage to, our assets. We currently operate three insurances that are relevant to risks in our network operation, for:

- public liability
- materials damage on stations, including zone substations, load plants and contained structures
- ground-mounted transformers.

It is not cost effective to insure the remaining sub-transmission and distribution systems with external providers. MainPower maintains a self-insurance fund to cover those network assets that cannot be insured cost effectively. The amount of insurance is reviewed regularly and held in a self-insurance fund.

4.6 Climate change

Our electricity assets are vulnerable to changes in climate and extreme weather events. The impacts of climate change are already being observed in the frequency and severity of storms in recent years resulting in extensive damage to MainPower's network and significant disruption to our customers. Table 4.3 summarises the physical and behavioural risk to assets due climate change.

Threat	Risk	Risk Treatment
Severe weather, wind speed and storms	• Asset damage caused by increased wind speeds and vegetation.	• Vegetation management, including an increase in tree scoping from 5 yearly to 2 yearly. • Use LiDAR technology for the management clearances. • Digital Twin technology for the modelling of increased windspeeds. • Increase community awareness of risks through our website, radio and community pages.
Wildfire	• Asset failure due to asset location in wildfire zones.	• Review loss of supply impact to consumers because of asset failure due to wildfire.
Rising sea levels/ex-treme flooding	• Assets failure due to flooding in low lying areas or susceptible to new flood zones. • Stranded assets due to shifts in the population.	• Conduct a review of asset locations in low-lying and coastal areas.
Changing supply/demand (Behavioural) trends	• Change in electricity consumption due to climate change, influenced by temperatures, consumes use of low carbon technology, carbon prices.	• Develop and implement network transformation road map that supports consumer engagement, use of pricing signals to manage network constraints.

Table 4.3: Risks related to climate change and their treatment

5. MAINPOWER'S NETWORK

5.1 Description of MainPower's electricity distribution network

MainPower's electricity distribution network extends from Kainga, Stewarts Gully and Coutts Island north of Christchurch City, through the Waimakariri, Hurunui and Kaikōura districts, up to the Puhi Puhi Valley north of Kaikōura, and inland to Lewis Pass.

The geographic extent of the network is represented in Figure 5.1, with each blue dot representing a consumer connection.

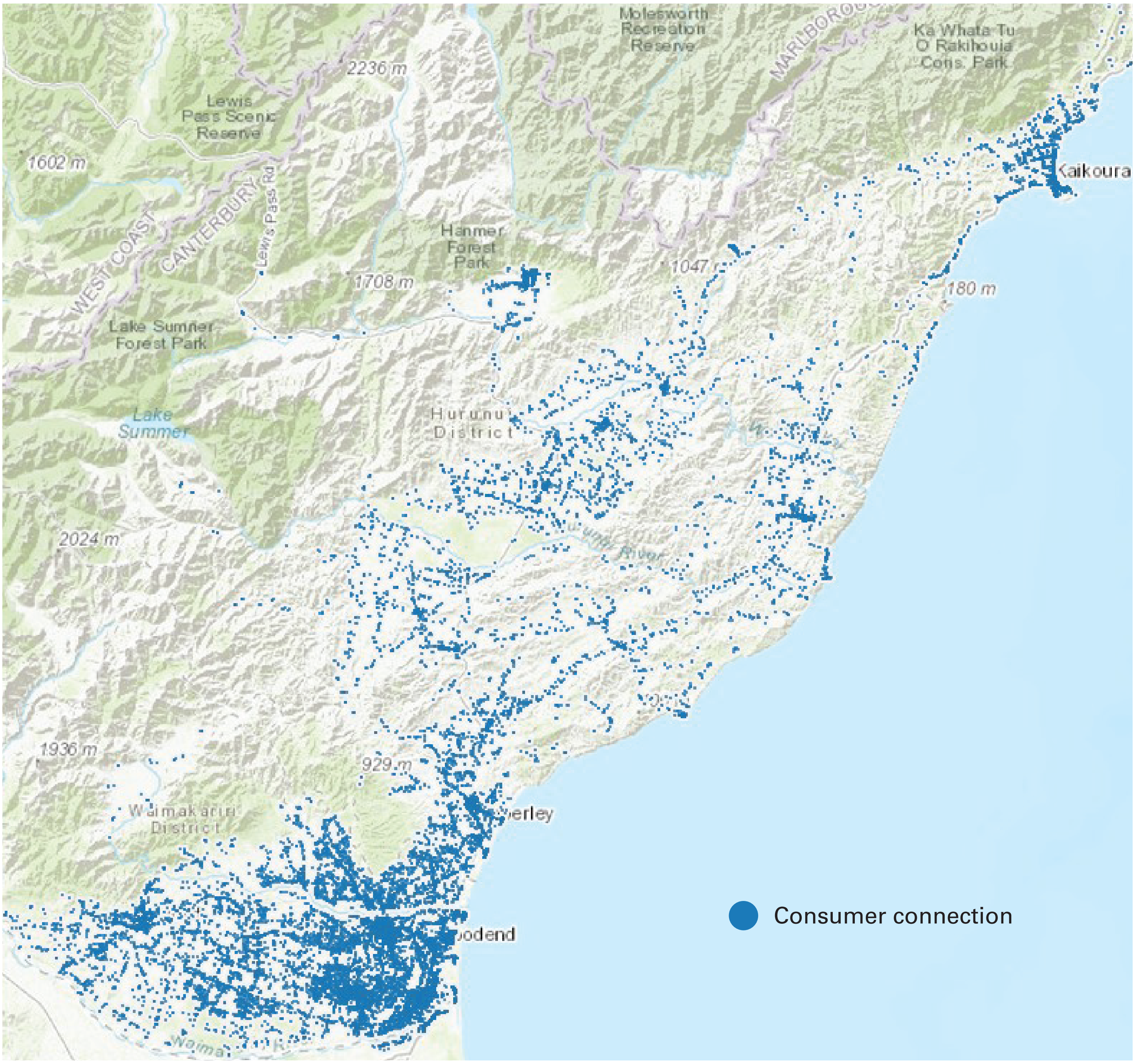


Figure 5.1: MainPower's electricity network consumer geographic distribution

5.1.1 Large consumers

Our large consumers are:

- **Daiken NZ medium-density fibreboard mill at Ashley:** The Daiken mill is supplied from the Ashley GXP via four 11 kV feeders, which provide reasonable levels of security. The Daiken controllers can disconnect power supply during emergencies, and maintenance is scheduled to coincide with Daiken maintenance programmes or times of low production.
- **Hellers meat-processing plant at Kaiapoi:** The site has undergone rapid growth, and the total load can be switched between two 11 kV feeders. Hellers has also installed a backup generator for critical supply during emergencies.
- **Sutton Tools NZ Limited tool-manufacturing plant in Kaiapoi:** This plant can be supplied from either of two 11 kV supplies from the Kaiapoi switching station, and one of these can also be swapped to an independent backup feeder.
- **McAlpines sawmill at Southbrook:** Recently, this mill has been transferred onto a new high-security dual-feeder-supplied switchboard, which has reduced the risk of power interruptions to the site.
- **McAlpines Mitre 10 Mega at Southbrook:** This site has an alternative 11 kV feeder.
- **Belfast Timber Kilns at Coutts Island:** This plant is connected near the end of a rural 11 kV spur line. No alternative supply is available at the site. Line maintenance is scheduled to coincide with plant maintenance programmes.

We also have several large supermarkets and other commercial businesses located in Rangiora, Kaiapoi and Kaikōura. The transformers for each of these sites are part of ringed feeders with RMUs, allowing alternative switching of supply in the event of a fault on one feeder.

5.1.2 Load characteristics

The following Table 5.1 trends the peak demand and timing of zone substation loads.

Substation	FY21 (MVA)	FY22 (MVA)	FY23 (MVA)	Peak
Southbrook	27.4	31.7	37.8	Winter
Swannanoa	15.1	15.0	15.7	Summer
Burnt Hill	15.5	14.1	14.8	Summer
Amberley	5.4	6.0	6.8	Winter
Mackenzies Road	1.8	2.3	2.0	Summer
Greta	1.4	1.4	1.5	Summer
Cheviot	3.5	3.4	3.4	Summer
Leader	1.5	1.5	1.4	Summer
Ludstone Road	5.7	5.8	6.2	Winter
Mouse Point	14.5	15.6	15.7	Summer
Hanmer	4.2	4.8	4.8	Winter
Lochiel	0.1	0.1	0.1	Summer
Hawarden	3.8	3.6	3.6	Summer
Kaiapoi GXP	31.6	32.2	34.6	Winter

Table 5.1: MainPower network load characteristics

5.1.3 Peak demand and total energy delivered

Table 5.2 trends the key system measures of the network.

System Measure	2021	2022	2023
Peak load	127.6 MW	123.5 MW	122.4 MW
Energy entering the system	666 GWh	662 GWh	656 GWh
Energy delivered	626 GWh	624 GWh	620 GWh
Loss ratio	5.9%	5.8%	5.4%
Load factor	60%	61%	61%
Average number of ICPs	42,117	43,130	44,108
Zone substation capacity (base ratings)	132 MVA	143 MVA	136 MVA
Distribution transformer capacity	580 MVA	588 MVA	599 MVA
Circuit length lines	5,165 km	5,170 km	5,198 km

Table 5.2: System Measures

	Average Number of ICPs		
Consumer Group ICPs	2021	2022	2023
Residential	34,087	35,451	35,868
Commercial	6,241	5,868	6,414
Large commercial or industrial	44	42	42
Irrigators	1,427	1,452	1,466
Council pumps	203	206	207
Streetlights	114	110	111
Individually managed consumer	1	1	1

Table 5.3: Key MainPower network statistics

5.2 Network configuration

5.2.1 Transmission network configuration

The 220 kV South Island transmission network is owned and managed by Transpower New Zealand Limited. Four 220 kV circuits supply Transpower's Islington Substation from the Waitaki basin, with double-circuit and single-circuit tower lines from Tekapo, Ōhau and Benmore following different routes to Islington. A single-circuit tower line also connects Livingston and Islington.

MainPower's distribution network is supplied via five Transpower GXPs from the 220 kV and 66 kV transmission circuits out of Islington (see Figure 5.2). Table 5.4 provides a summary of the GXP substations in the North Canterbury region.

Figure 5.2: Transpower's North Canterbury transmission grid

GXP	Description	
Kaiapoi	Transformer Capacity	76 MVA
	Firm Capacity	38 MVA
	Peak Load	29.5 MW
	Configuration	Two 38 MVA 66/11 kV three-phase transformers
	Supply to MainPower	Eight 11 kV circuit breakers
Southbrook 66 kV	Supply to MainPower	Four 66 kV circuit breakers (Swannanoa, Burnt Hill, Southbrook × 2)
Ashley ASY011	Transformer Capacity	80 MVA
	Firm Capacity	40 MVA
	Peak Load	13.9 MVA
	Configuration	Two dual-rated 40 MVA 66/11 kV three-phase transformers.
	Supply to MainPower	One transformer normally feeding five 11 kV circuit breakers supplying the rural area. One transformer normally feeding four 11 kV circuit breakers for the Daiken plant (which produces medium-density fibreboard).

GXP	Description	
Waipara **WPR0331 and 0661**	Transformer Capacity	160 MVA
	Firm Capacity	80 MVA to the 66 kV bus
	Peak Load	14.0 MW total at 66 kV, 7.9 MW at 33 kV
	Configuration	Two 80 MVA 220/66 kV transformers directly connected to the Islington–Kikiwa 220 kV circuits – the 66 kV supply from these transformers feeds a single 66/33 kV dual-rated 10/16 MVA three-phase transformer.
	Supply to MainPower	Two 33 kV and one 66 kV feeder circuit breakers and one 66 kV load plant circuit breaker.
Culverden **CUL0331 and 0661**	Transformer Capacity	60 MVA
	Firm Capacity	30 MVA to the 33 kV bus
	Peak Load	21.9 MW
	Configuration	Two 30 MVA 220/33 kV transformers directly connected to the Islington–Kikiwa 220 kV circuits – a 10/20 MVA 33/66 kV transformer rated at 13.09 MVA with no fans has been installed to supply 66 kV to Kaikōura.
	Supply to MainPower	33 kV via two feeder circuit breakers and cables, 66 kV feeder circuit breaker.

Table 5.4: Description of each GXP

5.2.2 Sub-transmission configuration

The locations of Transpower's GXPs supplying our network, along with MainPower's zone substations and 66 kV and 33 kV sub-transmission circuits, are shown in Figure 5.3.

Figure 5.3: MainPower's sub-transmission network

5.2.3 Distribution configuration

MainPower's distribution system is largely rural, with many long radial spurs. The 11 kV and 22 kV distribution is approximately 90% overhead-line network. The only areas of significant underground reticulation are Rangiora and Kaiapoi, where 11 kV reticulation is approximately 90% underground.

5.2.4 Distribution substations

As our high-voltage distribution network is predominantly overhead, most distribution substations are pole mounted. In rural areas, distribution substations are typically pole mounted for transformers up to 200 kVA and ground mounted above 200 kVA, although many irrigation consumers require their high-voltage spurs to be underground, with ground-mounted distribution substations. Pole-mounted transformers are protected with expulsion drop-out fuses and low-voltage high rupturing capacity (HRC) fuses where practicable.

The main urban areas have largely underground distribution with ground-mounted substations. Most substations located in residential or rural areas are located on private property within easements or on land purchased by MainPower. Our distribution substations consist of a range of construction types and designs, as outlined below:

- **Building substations:** These are large buildings or rooms of poured concrete, with stucco exteriors. They were generally built with exposed overhead 11 kV bus-work, but most have been changed to more modern ground-mounted RMUs. They are ideal locations for automated switchgear.

- **Kiosks:** These are smaller, predominantly front-access steel kiosks housing the transformers and switchgear. RMUs are used with an 11 kV HRC fuse protecting the transformer. The box design allows for a maximum transformer size of 500 kVA; however, these have to be de-rated because of reduced cooling. Low-voltage panels are typically the open-style Lucy HRC fuses, but many of these have been replaced with DIN standard switchgear.

- **Mini-sub:** These are mini-substation packages with RMUs in every second substation and air-mounted fuses in the remainder.

- **Outdoor transformers:** More recently, outdoor transformers with cable boxes and separate front-access outdoor cabinets have been used to allow for the use of low-voltage panels. This design affords more flexibility for a wider range of switchgear, changes in transformer size, better accessibility, and for the full rating of the transformer to be used.

5.2.5 Low-voltage distribution configuration

Approximately 70% of our low-voltage network is underground, typically located in the larger urban areas. Cables are typically terminated in plastic service boxes above ground, with larger link boxes used to create tie-points between substations, where practicable, increasing security of supply.

Overhead low-voltage systems are located in smaller townships and rural areas to enable cost-effective supply to a number of consumers from one transformer. Most overhead low-voltage conductors are bare conductor or covered copper.

Almost all new low-voltage reticulation since 1990 has been underground. Conversion to underground reticulation is the preferred replacement strategy for old low-voltage lines, where this can be justified economically.

5.3 Overview of assets, by category

5.3.1 Sub-transmission

The sub-transmission system is a mixture of 33 kV and 66 kV circuits on hardwood poles, with newer lines predominantly constructed using concrete poles, with a few short-cabled sections.

5.3.2 Zone substations

Network assets are housed within zone substation buildings or on zone substation sites, including power transformers, circuit breakers, disconnectors and projection systems.

Zone substation transformers above 1 MVA capacity have on-load tap-changers to regulate the bus voltages, with loads typically kept below the manufacturer's ratings. These transformers have been subject to normal and typical urban and commercial load curves and cyclic loading.

5.3.3 Overhead distribution

Historically, large numbers of hardwood poles were used on the overhead network. Larch poles impregnated with creosote were used in the late 1950s through to the 1960s, in combination with hardwoods. Treated Corsican pine poles were used from 1973 and concrete poles were also purchased from the mid-1970s. The main pole types used today are H5-treated radiata pine and pre-stressed concrete.

During the past 12 years, many lines have been converted from 11 kV to 22 kV by changing the insulators. This has largely been undertaken in rural areas experiencing high growth in irrigation demand and dairy conversions.

5.3.4 Underground distribution

Most of the high-voltage underground cables are either 95 mm2 or 185 mm2 aluminium, although more recently, 300 mm2 aluminium cables have been used for major urban feeders or to supply distribution switching stations. Smaller sizes are being used for rural customer spurs.

5.3.5 Distribution substations

Most customers are supplied from primary distribution substations at voltages of 11 kV or 22 kV. A small number of customers are supplied from single-wire earth return systems operating at 6.6 kV or 11 kV, and a very small number of remote customers from distribution transformers on the 33 kV sub-transmission system. However, as this arrangement constrains the operation of the sub-transmission system, they are progressively being removed.

Substations are either ground mounted outdoors or within an enclosure, or pole mounted. As our distribution area is mainly rural, most substations are pole mounted. Most recent designs have used mini-subs, micro-subs or the Pegasus Modular configuration, using a stand-alone transformer with high-voltage and low-voltage cable boxes and a separate shell for the high-voltage and low-voltage switchgear.

MainPower has more than 7,500 distribution transformers, which come from a variety of manufacturers, including Tyree, ABB, Astec, Tolley and Wilsons. Large quantities of transformers were purchased between 1967 and 1973 because of the growth in the distribution network at this time. Many of these were in the 10 kVA to 30 kVA range.

5.3.6 Distribution switchgear

There are several different types of circuit breakers and reclosers on the system, including bulk oil, SF6 and vacuum types. All circuit breakers purchased since 1995 are remote controllable.

Most of the air break switches installed between 1950 and 1980 were Canterbury Engineering types 955, DA2, DA27, NL7 and NG10. More recently, Schneider's integrated spar-mounted air break switches and Electropar EPS2 switches have been used. Sealed switches are replacing critical air break switches and almost all are remote controlled.

During the 1970s and 1980s, ABB's SD range of oil RMUs were used, followed in the 1990s by increased use of air-insulated Holec MD series (Magnefix) switchgear. The Holec Xiria sealed air-insulated range has also been used since year 2000.

5.3.7 Load control

We employ Landis+Gyr SFU-G and SFU-K ripple injection plant using Decabit code for load control and tariff switching. The plants operate at an injection frequency of 283 Hz, and all plants are GPS synchronised.

Most of the receiver relays are in new smart meters or are Zellweger/Enermet RM3, installed between 1993 and 1997. The remainder are the later Landis+Gyr RC5000 series, while more-recent purchases are RO3-type relays.

5.3.8 Streetlights

Most street lights are controlled by ripple relays located at local low-voltage distribution substations, where the relays receive a signal by ripple injection initiated from a light-level sensor. Dedicated street light supply cables loop around several lights from each control point. A small number of lights are controlled from local photocell sensors. Street light relays are modern and reliable, with extremely low reported failure rates

5.3.9 Supervisory control and data acquisition

MainPower implemented and deployed the Open Systems International Monarch ADMS in FY20.

MainPower's first Supervisory Control and Data Acquisition (SCADA) system used remote terminal units communicating with Conitel protocol, and these have now either been completely changed to more modern DNP3 remote terminal units or slaved to more modern remote terminal units on site. All remote sites now communicate via the DNP3 protocol. Work is proceeding on new field devices with remote communication facilities. We are committed to using the latest distribution automation technologies to improve system performance and fault response times.

5.3.10 Communications

Our voice and data radio equipment has migrated to new systems during the past eight years and operates reliably. Tait voice radios and Mimomax data radios are currently employed. During 2016, "lone worker" and "worker down" functions were added to the voice radio platform via the use of portable radios working through the base vehicle radio.

5.3.11 Protection and metering systems

All modern zone substations use Areva, SEL or Siemens digital electronic protection systems. Older substations have GEC electromechanical relays, which are still reliable but have limited setting ranges and functionality. Several individual relays in these substations have been replaced in conjunction with circuit-breaker replacements. We also own high-voltage metering systems for several large users, including the Daiken medium-density fibreboard plant and McAlpines' timber-processing plant.

5.3.12 Power factor correction plant

While MainPower has no system power factor correction installations of its own, the Daiken medium-density fibreboard plant at Ashley has two 11 kV capacitor banks. Transpower has also installed power factor correction for voltage support on the 66 kV bus at Southbrook.

5.3.13 Property and buildings

MainPower owns substation buildings, offices, administration buildings and operational buildings. All our buildings are managed by MainPower's Service Delivery Department and maintained by internal and external resources.

5.3.14 Assets owned at transpower grid exit points

MainPower owns metering and communications equipment at Transpower GXPs that connect to our network. These monitor load for load management and revenue metering. All have Ion-type meters, installed after year 2000. MainPower's ripple injection plants are located in Transpower GXPs at Waipara, Ashley and Kaiapoi. We also have SCADA and local service equipment associated with load control at these sites.

5.3.15 Mobile substations and generators

We have invested in a mobile diesel generation plant to assist with reducing the number of planned interruptions. The plant is rated at 275 kVA. The generator has been fitted on a tandem-axle truck along with the transformer, protection systems and connecting leads. The generator is used during planned work to maintain the supply to customers, and it has enough capacity to supply the average load of an urban transformer kiosk. Alternatively, it can be connected to overhead lines at 11 kV or 22 kV, supplying up to 100 customers. We also have a 500 kVA generator for use with low-voltage customers. This is often large enough to supply small subdivisions during maintenance.

5.4 Network of the future

A network of the future enables the widespread use of local generation sources connected to the network at multiple points, with associated two-way power flows. It also ensures open-access arrangements for consumers to allow them to transact over the network and to connect any device they wish within acceptable safety and reliability limits. In addition:

- It relies on physical assets to convey electricity, as well as from consumer to consumer, or consumer to bulk supply point.
- Consumers are actively involved in their energy acquisition, generation and consumption management.
- It provides network connections for multiple sources of distributed generation devices and other consumer-side devices.
- The distribution utility may not become involved in the transactions between consumers and other parties, nor in the balance between supply and demand.
- Network stability is managed by the EDB for a range of operating scenarios.

5.4.1 Network Transformation Plan

More work is required to achieve distribution system integrator status. This work is summarised in Table 5.5, including how we are tracking to complete these workstreams.

Objectives	Description	Description	Status
Consumer Insights	Understand consumer motivations and behaviours to determine: 1. the impact on distributed energy resource deployment and consumption patterns 2. new load requirements	• Low-voltage monitoring strategy • Understand distributed energy resource deployment through scenario planning • Understand new loads • Understand new DG	• Trial low-voltage monitoring deployed • ADMS reports on ICP outage basis • Using and further developing scenario based planning • DG support for Kate Valley and Mt Cass Windfarm'
Managing Uncertainty	• Stay abreast of technology developments and update the EDB industry • Update this roadmap to remain relevant	Continuous monitoring	Ongoing
Open Network Framework	Access to the electricity distribution network by existing and new consumers and traders to connect and operate any equipment they desire (specifically distributed energy resources and new loads) with appropriate consideration of: • cost of access • network operation and system security • standard equipment • standard access arrangements	• Enable distributed energy resource trading • Trial distributed energy resource and demand response for network support • Establish MainPower flexibility framework.	Currently reviewing how distributed energy resource and DG can be contracted differently, taking advantage of an intermediary as opposed to a pricing tariff, which is the existing method.
Standardise Technical Arrangements	• Provide consistent method of connection of any equipment (distributed energy resources or appliances) across all EDB areas • Ensure equipment complies with approved standards to minimise its impact on the electrical power system	• Standard distributed energy resource connection standards • Equipment standards • Network engineering • Cyber security and autonomous distributed energy resource	Already engaging with other EDBs to support consistent agreements, equipment standards and asset management practices
Network Operation, Monitoring and Stability	Ensure the stability of the open network through deeper monitor-ing of the network and improved planning techniques	• Low-voltage monitoring and visibility • Understand impact on network stability of multiple distributed energy resources	• Low-voltage monitoring remains a work in progress • Roadmaps are developed to deliver: - power flow management - state estimator - Volt-Var, and compensation - fault location isolation and service restoration
Build EDB Capability	• Understand networks in greater depth, their ability to host distributed energy resources, congestion, and contracting for network support • Ensure working understanding of regulations and obligations	• Procurement and contract for services management • Asset management maturity	• Contestable customer connections and network access for third parties are developed and implemented • Maturity improvements include upgrades to MainPower ERP and the implementation of CBRM models

Table 5.5: Network Transformation Plan

6. NETWORK DEVELOPMENT PLANNING

Network development planning is a significant focus for MainPower within our Asset Management Framework and processes. Given the changes already identified and the ways MainPower's network is predicted to be used in future, the current traditional distribution network approach of demand-based, deterministic development planning will no longer meet the future needs of our consumers – both current and new market participants.

The underlying elements and influences of these changes from the perspective of an EDB are:

- significantly greater integration between DG, transmission, and energy storage on the network, together with increased interaction with active traditional consumers
- new technologies producing variable power sources, two-way power flows and new demands that are already creating serious challenges on networks internationally
- the impact of new commercial parties, models, and business platforms, working through both the distribution network and the "internet of things" but impacting on the use of the network
- a growing focus on energy communities, peer-to-peer trading, and local markets
- the impact of non-linear loads, such as rapid EV chargers, on standard network infrastructure and the ability to manage the significant demand peaks and power-quality issues these introduce at the low-voltage distribution level
- the potential for use of separated distribution micro grids where these are the most economical solution when considering renewals or new supplies
- the national transition to a low-carbon economy.

The above can be summarised as highlighting the need to move from the traditional passive distribution network to an active network that has more dimensions.

In response to this, MainPower is continuing to re-evaluate and evolve its network development-planning methodology. In simplistic terms, we see the need to move from the traditional distribution network approach of demand-based, deterministic planning to scenario-based planning. To achieve this, new skills and systems will be required. We are actively engaged in identifying how these requirements will be met through learning from the experiences of others (both locally and internationally) and by participating in the results, learnings and tools being made available from industry working groups such as the Electricity Networks Association and EEA. This evolution of our network development approach will help us better understand the range of capacity and energy service requirements the network will need to provide.

We also recognise that this new future for distribution networks offers increased opportunities for non-network solutions (where economically viable) and for existing and new market participants to provide energy solutions. MainPower recognises the need to identify these opportunities in a timely manner to facilitate the market response and potentially seek providers of non-network solutions.

Although we are evolving our network development-planning processes to accommodate the above changes, our network development plans are primarily driven by safety, security of supply, resiliency, reliability and compliance requirements – these will evolve to include the future requirements for the North Canterbury region.

The following section identifies the current deterministic planning process, with some innovation based on our thinking about the future and early movements to a new model of network development planning.

6.1 Project prioritisation

A risk-based approach is applied to establish project prioritisation, in combination with other factors such as:

- compliance and safety
- meeting service obligations and targets as defined by our consumers
- cost–benefit analysis
- options analysis.

In general terms, development projects are prioritised as follows:

- addressing compliance, health, safety and environmental issues
- consumer-driven projects for new connections or upgrades
- providing for load growth
- meeting consumer service levels.

Prior to the commencement of each planning period, potential projects for the following 10 years are identified. Inputs to the prioritisation process include:

- determining the primary driver for the project
- impact on consumers if the project does not proceed, or if it is deferred
- seasonal requirements
- cost and funding implications
- alternative non-network solutions
- planning uncertainties.

6.2 Security of supply classification

The following sections describe how we define security of supply classifications for zone substations and distributed connected loads.

6.2.1 Zone substation security

Zone substations are classified for security according to Table 6.1.

Substation Class	Substation Load Type	Targeted Duration for First Transformer, Line or Cable Fault	Targeted Duration for Bus or Switchgear Fault
AAA	Urban or industrial load > 10 MW peak or 30 GWh annual consumption	No interruption	No interruption for 50% and restore the rest within 2 hours
AA	Urban load > 2 MW peak or 6 GWh annual consumption	45 minutes	Restore 75% within 2 hours
A1	Predominantly rural and semi-rural loads totalling > 1 MW	Isolation time	Repair time
A2	Predominantly rural and semi-rural loads totalling < 1 MW	Repair time	Repair time

Zone Substation Classification Descriptions:

AAA Supply is uninterrupted in the event of the outage of one major element of the sub-transmission network. Load can be transferred to other substations without interruption by switching on the network, if necessary, to avoid exceeding ratings.

AA Supply may be lost in the event of the outage of one major element of the sub-transmission network. Supply can be restored within 45 minutes by switching at the sub-transmission or distribution level.

A1 Supply may be lost in the event of the outage of one major element of the sub-transmission network. Supply can be restored by switching after the faulted element is isolated.

A2 Supply may be lost in the event of the outage of one major element of the sub-transmission network. Supply cannot be restored until the faulty element is repaired or replaced.

Table 6.1: Security of supply zone substation restoration times

6.2.2 Distributed load classifications

Distribution loads are classified according to Table 6.2.

Classification	Description
L1	Large industrial (> 5 MW/15 GWh of industrial load)
L2	Commercial/Central business district (> 5 MW/15 GWh of commercial load)
L3	Metropolitan (> 2 MW/6 GWh of urban mixed load)
L4	Rural (predominantly rural and semi-rural areas)
L5	Remote rural

Table 6.2: Security of supply load types

6.2.3 Security level

Network configuration is arranged so that the security criteria shown in Table 6.3 can be met, subject to technical and economic feasibility.

Load Type	Security Level
L1	After a fault is located, supply can be restored to all but the isolated section in 1 hour. The isolated section shall be limited to 500 kVA, unless it is a single consumer with a load in excess of this.
L2	After a fault is located, supply can be restored to all but the isolated section in 2 hours. Restoration of supply via low-voltage connection is acceptable here. The isolated section shall be limited to 750 kVA, unless it is a single consumer with a load that is in excess of this.
L3	After a fault is located, supply can be restored to all but the isolated section in 3 hours. The isolated section shall be limited to 1.5 MVA or 4.8 GWh.
L4	After a fault is located, supply can be restored to any section of the feeder with a load exceeding 1.5 MVA or 4.8 GWh in 4 hours.
L5	After a fault, supply may remain interrupted until repairs are completed.

Table 6.3: Distribution load security level

6.3 Use of standard designs

Standard designs are used to achieve, and are aligned with, MainPower's asset management objectives. Standard designs exist for all MainPower overhead structures. Work is currently being undertaken to further standardise our engineering solutions. Standard designs are identified through:

- total cost of ownership
- economies of scale
- compliance
- service levels
- security of supply
- safety.

6.4 Strategies for energy efficiency

MainPower has a focus on improving the energy efficiency of our network through reducing losses (where reasonably practical), placing a high value on efficiency parameters when purchasing new equipment, and on education programmes to improve demand-side management.

All conversions from 11 kV to 22 kV will cause a replacement transformer to be installed that meets the new Minimum Energy Performance Standards. Additionally, we consider loss capitalisation when purchasing transformers. As a company, MainPower actively promotes energy efficiency in the community through consumer education and our community sponsorship programme (insulation and energy efficiency solutions). We are actively engaging with our consumers and assessing demand-side management concepts regarding emerging technologies and consumer behaviour.

6.5 Network planning

6.5.1 Overview

We use the term “growth and security” to describe capital investments that increase the capacity, functionality or size of our network. These include the following four main types of investments:

- **Major projects** – involving sub-transmission, zone substation or GXP works.
- **Network reinforcement** – focused on the distribution network such as feeder capacity and voltage upgrades, security (N-1) reinforcements, distribution substation and transformer upgrades, and low-voltage reinforcement.
- **Future network** – investments to support the transition towards an open-access network, including network monitoring, communications, power-quality management and flexibility services.
- **Reliability and automation** – includes network automation projects to help manage the reliability performance of our network; currently integrated within our major projects and reinforcement projects programme.

6.5.2 Regional demand trends

Our network demand-forecasting process forecasts demand at Transpower’s North Canterbury GXPs and MainPower’s zone substations over the next 10 years.

When developing demand forecasts, several key inputs are applied, including:
- population and household projections obtained from Stats NZ
- local district schemes and community plans
- notified changes in land use designations
- known commercial, residential and industrial developments
- historical electrical demands
- non-network solutions (such as demand management and flexibility services)
- historical extreme movements in temperature and rainfall where this affects peak demand
- expected commercial developments
- emerging technology adoption, such as EVs.

Our network continues to undergo steady growth, as shown by both ICP and population growth in Figure 6.
The consistent growth shown in the network is mainly due to:
- steady residential subdivision activity in Amberley, Kaiapoi, Pegasus/Ravenswood, and Rangiora
- commercial development in Rangiora and Ravenswood

Growth in each area of our network varies because of changes in demographics and regional characteristics. The map in Figure 6.2 indicates annual ICP growth rates, by planning area, for MainPower’s network region.

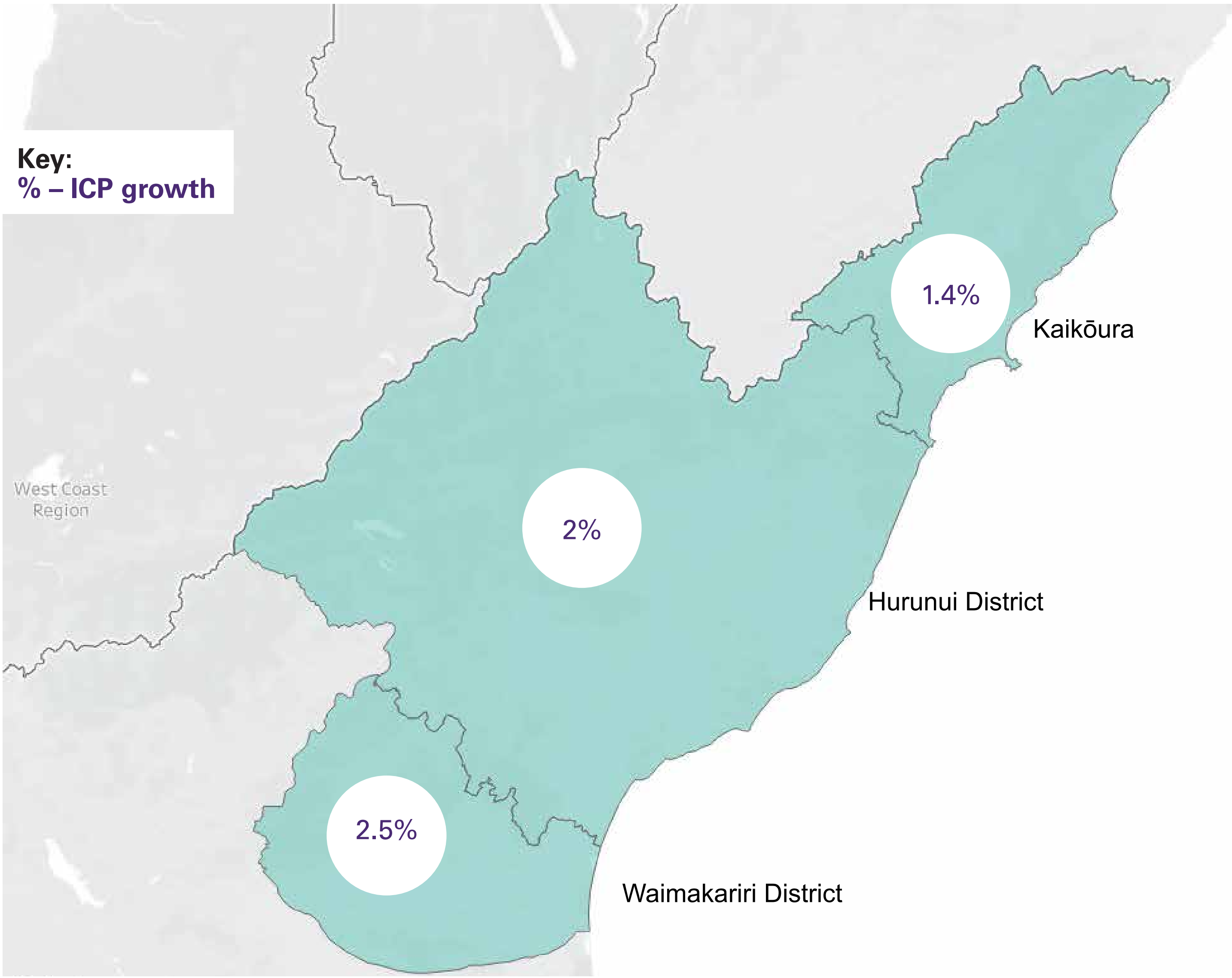


Figure 6-1: Annual ICP and population growth rates by planning area

6.5.3 Reliability

The number and duration of service interruptions are of primary interest from the consumers' point of view, as specified in Section 3 of this document. MainPower uses reliability statistics and targets to identify if and where system improvement is needed. We select development options based on the lowest whole-of-life cost to provide target reliability outcomes.

6.6 Network development planning

Our network development is informed by our future planning scenarios, our ability to meet defined levels of service and performance, and standard design implementations, which are a function of:

- system growth (capacity)
- decarbonisation and distributed energy resources
- security of supply
- reliability
- resiliency.

We use options analysis to consider alternative development and engineering solutions.

When selecting a solution, we consider cost and sustainability.

Figure 6.1 shows our process for network development planning and capital investment, and how we ensure our investment programme supports our asset management objectives.

Figure 6-2: Network development planning process

6.6.1 Future scenarios

We have developed three scenarios to understand the potential impacts of regional change and decarbonisation on expected network loads. These scenarios use historical data and regional growth information to develop foundational growth projections to then overlay decarbonisation scenarios to understand the possible impacts for each network region. These scenarios provide us with a view of possible energy futures, allow us to monitor how we are tracking against the scenarios, and ensure alignment with our investment pathway.

The scenarios summarised below relate to a low-carbon future as our region grows and transitions to more renewable energy.

- Scenario 1 – Optimised Energy System: Continuation of base energy growth with high technology adoption and support for whole-of-system coordinated energy management across the energy system. High levels of electrification, offering flexibility solutions to extract value in distributed energy resources with ability to dynamically manage network peaks and match load with lowest cost generation. Requires a high degree of coordination across the full energy system and provides ability to leverage the capability of artificial intelligence (AI) for system optimisation.
- Scenario 2 – Smart Sustainable System: Continuation of base energy growth driven by regional development, with consumers embracing a smart, low-carbon energy transition and balanced adoption of technology, including use of distributed energy resources and flexibility (demand response) services to support New Zealand's decarbonisation journey. Electrification of transport and renewable generation follow New Zealand Government targets.
- Scenario 3 – Un-coordinated Rapid Growth: Increase in regional development resulting from increasing population and commercial investment in the region, combined with more aggressive regional decarbonisation. Low support for use of smart technologies or flexibility services (such as grid-connected batteries and distributed energy resources) resulting in growth contributing to network peaks without coordination or ability to centrally manage.

Our staged approach to scenario-based planning is initially focused on defining and monitoring inputs and assumptions to further develop and refine our scenarios, which we will then apply to our network and establish investment requirements for each scenario and will ultimately inform our strategy and long-term investment plan.

6.6.2 System growth (capacity)

We must ensure there is sufficient capacity available to meet network system growth. This is provided in conjunction with our existing demand-side management capability and use of flexibility services.

We follow a process of monitoring existing loads on the network, forecasting network energy requirements and assessing this against our network capability and Security of Supply Standard to establish the areas where we may experience a shortfall in capacity at a defined security level.

We plan to implement and monitor more extensive security performance indicators to show the capacity available across the network at each security level.

6.6.3 Power-quality compliance

One of the key criteria for distribution development planning is power-quality compliance, such as voltage. Voltage performance is monitored by SCADA using field voltage measurements, load flow analysis, manual voltage checks (under normal and abnormal configurations) and investigations into consumer complaints about power quality.

Voltage regulators are used at 11 kV and 22 kV to assist in maintaining the voltage within the statutory voltage limits. Zone substation voltage regulators are generally set to control in the 100–102% band of nominal voltage at sites with 1.25% control steps. With line drop compensation, voltage regulation is set to control within the 11,000 V to 11,300 V band. Line drop compensation is rarely used because of the large consumer spread along the distribution lines.

Field voltage regulators generally have 0.625% control steps and are set to operate in the range 10,900 V to 11,000 V.

Systems are generally designed to have less than 10% total voltage drop to the network connection point to allow for additional voltage drop when the system is being supplied in an abnormal configuration (e.g. during an equipment outage). In normal operating configurations, this also allows for the bus voltage to be reduced by 1% to facilitate a higher penetration of DG.

6.6.4 Security of supply

Security of supply is the ability of the network to meet normal demand under contingency events, such as equipment failure. The more secure the network, the greater the ability to continue to provide supply during a contingency or to perform restoration from a fault or series of faults.

Note that security of supply differs from reliability. Reliability is a measure of how the network actually performs and is measured through indices such as the number of times supply to consumers is interrupted.

6.6.5 Forecast impact of distributed generation and demand-side management

All demand forecasts take into consideration the impact of existing DG connections and proposed DG sites known to MainPower through engagement with our consumers. This includes energy-efficiency initiatives, with the major contributor being irrigation schemes converting to piped irrigation. Our load-forecasting process considers the impact of the Demand-Side Management scheme that MainPower already employs.

Figure 6.3 and Figure 6.4 show the growth of small DG sites (< 1,000 kW capacity) distributed within the network. The connection rate is increasing slowly. On average, approximately 476 kWh of generation is exported per kW of capacity.

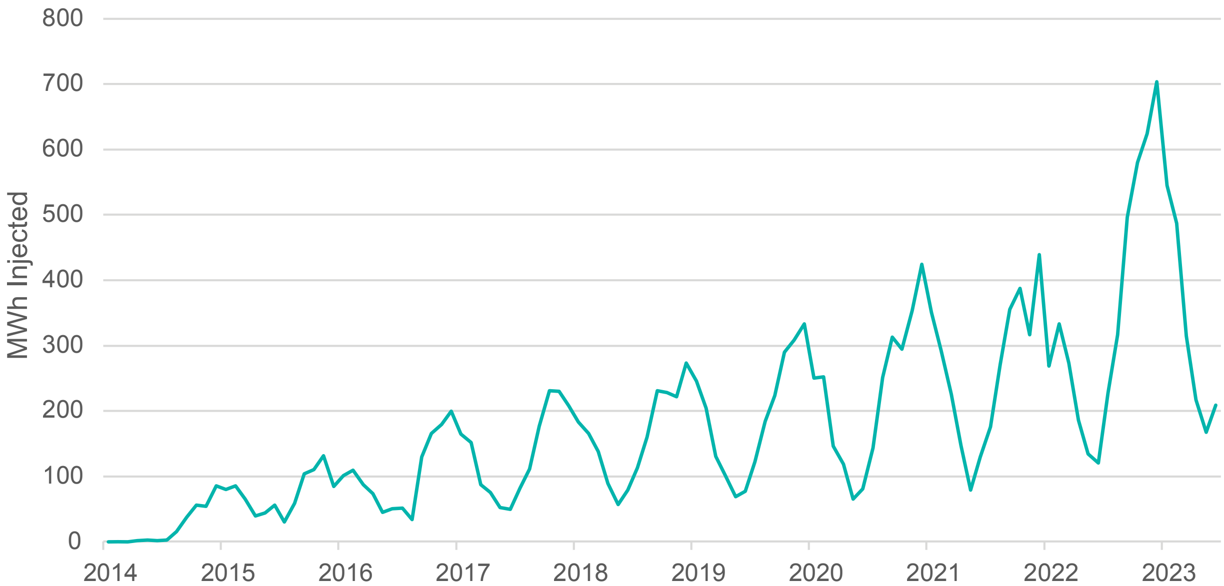


Figure 6-3: Power supplied by distributed generation sites with capacity less than 1,000 kW

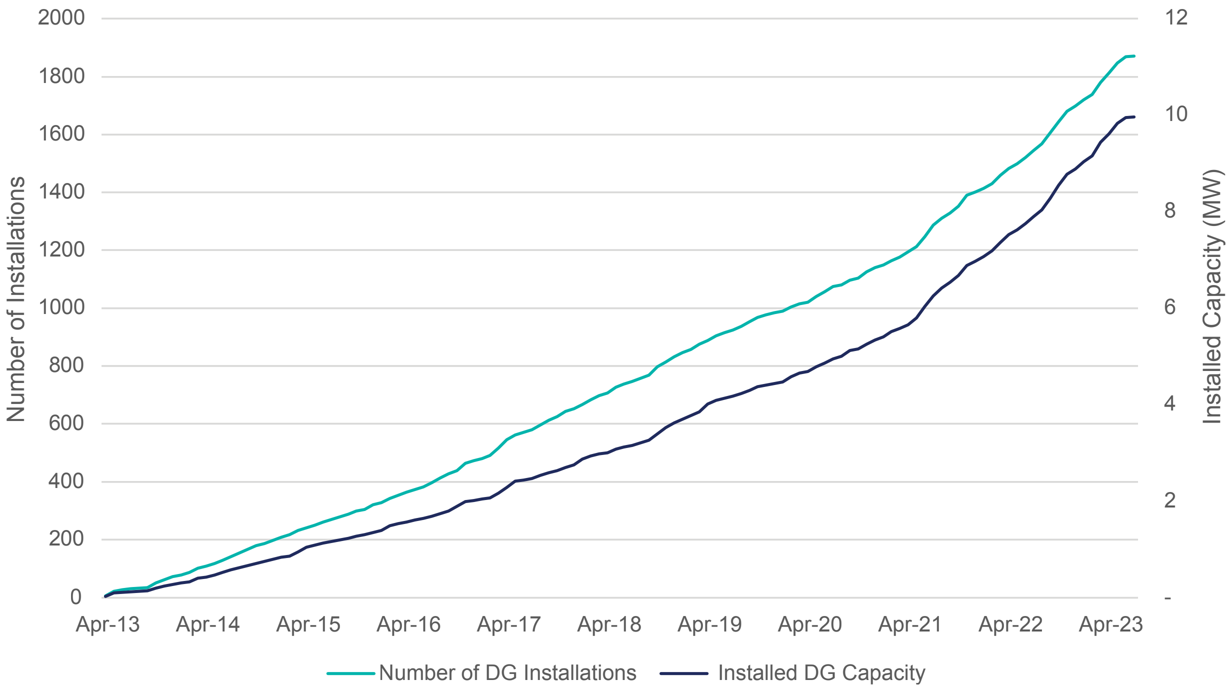


Figure 6-4: Distributed generation installations on MainPower's network (individual size less than 1 MW)

6.6.6 Impact of new connections on network operations or asset management priorities

6.6.6.1 Assessing the impact of new demand, generation or storage

Measuring the scale and impact of new demand
MainPower observes substation peak measurements to quantify total network load and generation. These coincident peaks are used to forecast energy needs in our community and to reinforce the network as and where appropriate. Measurement of specific point loads can be done with installed low-voltage monitoring equipment. This is typically reserved for areas of the network that MainPower is aware are becoming heavily loaded and distribution transformers may need to be upgraded.

Growth forecasting is completed using a range of information, from historical demand figures to council-estimated population growth and new technology (e.g. EV) uptake rates. These factors are brought together to give an indication of the expected network growth.

MainPower currently does not forecast or assess the impact of generation or energy storage. As load forecasting gets more mature, it is expected that both factors will be taken into consideration.

Taking account of the timing and uncertainty of new demand, generation and storage capacity

MainPower uses scenario planning to estimate the impact of variable uptake rates of EVs and population growth. The underlying model assumes correct council predictions for population growth and EV uptake targets to assess the required network growth rates. From there MainPower builds scenarios around this base case to define faster or slower growth.

MainPower currently does not plan for unknown future large point loads or utility scale generation connections due to the uncertainty inherent with this process.

Taking account of other factors (e.g. network location of new demand, generation and storage capacity)

MainPower uses regional population figures to determine the expected population growth in the three council regions within our network area. This provides a baseline expected growth that needs to be accounted for. Beyond this, MainPower relies on applications for connection and council planning/consenting information to determine likely areas of significant future growth. For large point loads and utility scale generation, MainPower will begin planning after the application has been received as these types of connections are typically applicant funded.

6.6.6.2 Assessing and managing the risk to the network posed by uncertainty regarding new demand, generation and storage capacity

MainPower uses load forecasting tools with scenario planning to minimise the likelihood of unexpected demand increases. This forecasting is used to assess the timing of significant network upgrades to ensure they are completed before issues arise. The suitability of load forecasts are regularly monitored to ensure any significant load or generation changes in the network are captured.

MainPower does not currently forecast or attempt to anticipate new generation or storage on the network as this is likely to result in increased costs to our customers.

6.6.7 Innovation practices

6.6.7.1 Innovation practices planned or undertaken since the last AMP

As MainPower is an exempt EDB under the Commerce Act, we do not identify innovation projects as defined by the Commerce Commission. We do, however, undertake the following innovative projects to ensure our customers are getting the best outcomes.

- **Low-Voltage Network Visibility** – MainPower is actively working to secure access to low-voltage smart meter data to create better visibility and understanding of our low-voltage network. This data can be used in conjunction with the third-party software platforms to provide this visibility and understanding. The platform also offers the ability to identify locations with distributed energy resources connected, including EVs. The knowledge provided by this platform, and smart meter data, will allow MainPower to better prepare the low-voltage network for increased distributed energy resource penetration and enable us to identify and rectify any power quality issues much faster.

- **SINCAL Integration** – MainPower has integrated our GIS with SINCAL, our network modelling and load flow software. This provides MainPower with an entire network model, down to the distribution level, which is used to simulate the impact of network changes, load growth patterns and new loads/generation on the network. This allows us to direct funding at the weakest areas of the network to ensure the best service levels for consumers.

- **Weather Data Integration** – MainPower is working with providers of weather and climate data to better inform fault response and reliability investigations. By having weather data in real time and forecasting, MainPower will be able to better plan resources for storm response and identify any reoccurring weather phenomena that result in outages on certain parts of the network that currently have no identified cause.

6.6.7.2 Desired outcomes of any innovation practices, and how they may improve outcomes for consumers

All innovation projects undertaken by MainPower strive to increase network visibility to minimise long-term capital expenditure. This improves outcomes for consumers through lower energy costs and potentially increased rebates. Additionally, the network visibility will enhance MainPower's ability to target weaker network areas with reinforcement spending resulting in easier facilitation of customer energy choices, whether it be EVs, DG or any other new technology.

6.6.7.3 Measuring the success and making decisions regarding innovation practices

For a new project to be successful it must provide more economic benefit to our customers than it costs them to implement. MainPower will commence a project when it makes operating, controlling or observing the network simpler, easier or safer. A scope will be written with specific deliverables and expected outcomes or improvements from each project and a trial undertaken. If this trial fails to meet the expectations laid out in the scope, MainPower will discontinue the project. If the scope is met, MainPower will move forward with the project.

6.6.7.4 How the decision-making and innovation practices depend on the work of other companies

MainPower relies on both internal resource and third parties to provide innovative solutions to identified problems. When looking at network reinforcement projects, MainPower will consider non-network solutions and, where appropriate, will go out to market for these.

In relation to the identified innovation projects above, MainPower has utilised internal resources where available to determine the best outcomes. Following this, third parties are engaged to offer solutions to the identified problems. MainPower relies on these third-party companies to provide data and software to be used internally for better network visibility and decision making.

6.6.7.5 The types of information used to inform or enable any innovation practices, and the approach to seeking that information

MainPower is actively seeking ICP smart meter data to improve network visibility and investment decision making. The current approach to seeking this data is to talk directly to the smart meter owners and attempt to enter commercial agreements for access to this data.

MainPower is also seeking weather data from NIWA to better plan resource allocations around storm events and to find trends in weather and outages. This will inform network reinforcement work to improve customer reliability.

Data is a key asset to MainPower and will continue to grow in importance. As a result, MainPower invests in the data capture, storage and management where appropriate and justified to get the best returns for our customers.

6.7 Long-term sub-transmission network strategy

MainPower has developed a long-term sub-transmission strategy to help inform and align future investment (see Figure 6.5). This long-term strategy targets the following key objectives.

- Enable and support regional growth.
- Provide an appropriate security of supply.
- Facilitate continuous improvement in network reliability.
- Standardise sub-transmission and distribution assets.
- Facilitate consumer-driven technology adoption.

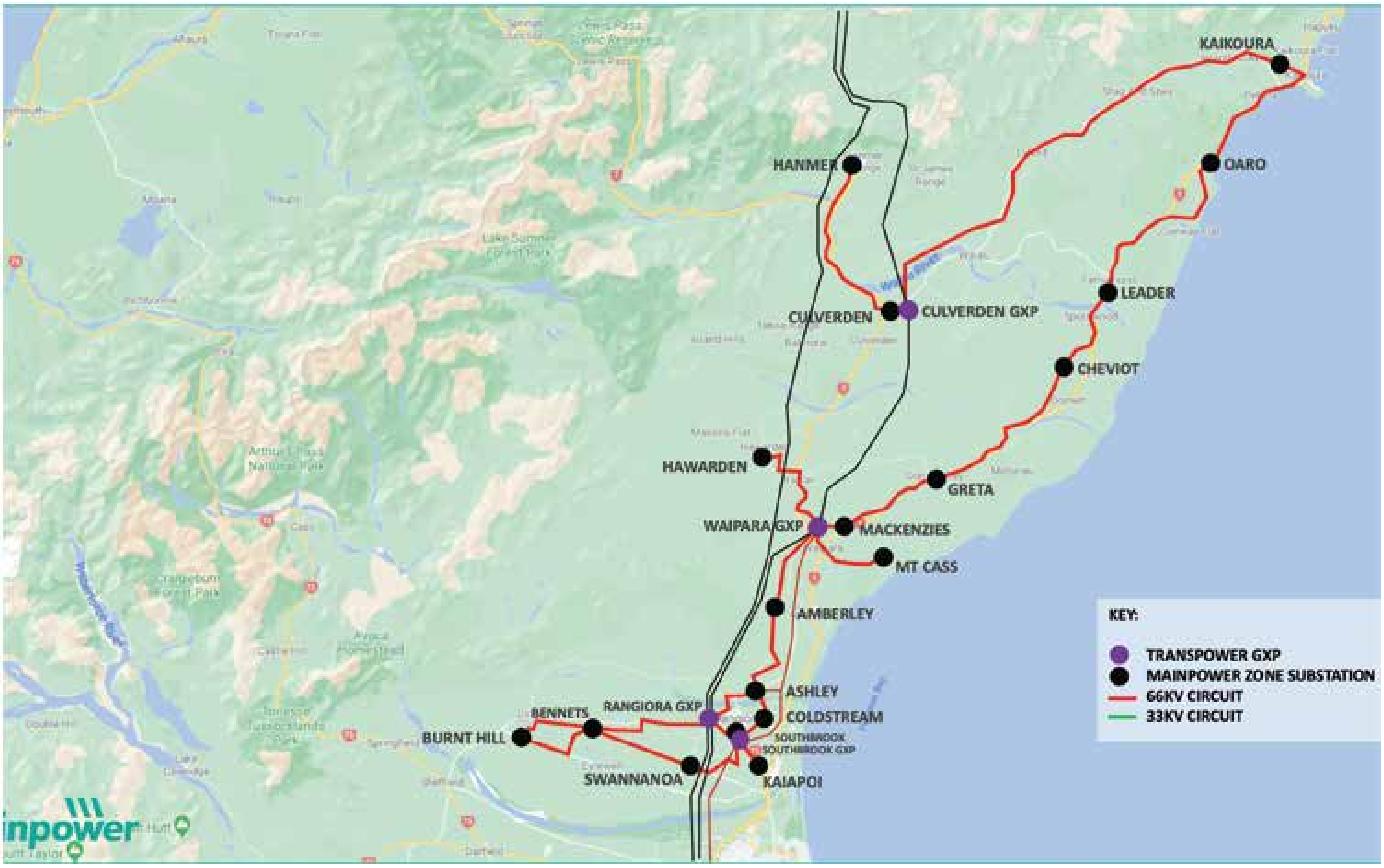


Figure 6 5: MainPower's long-term sub-transmission network strategy

The Network Regional Plans identified in the following sections have been developed to align with and facilitate MainPower's long-term sub-transmission network strategy.

6.8 Network regional plans

MainPower's network spans three main regions across North Canterbury: Waimakariri, Hurunui and Kaikōura. We have divided the network into these planning areas to better understand and focus our investment planning to local needs. These area plans are summarised below.

6.8.1 Waimakariri regional overview

The Waimakariri area plan covers the region from the Waimakariri River to Balcairn, and between the South Island's east coast and the Main Divide. The main towns include Kaiapoi, Oxford, Pegasus, Rangiora and Woodend.

The region's proximity to Christchurch has contributed to its substantial residential growth, further supported by Waka Kotahi NZ Transport Agency projects to further develop the Christchurch Northern Motorway.

The region is characterised by flat, open plains used for a range of farming activities, combined with an increasing number of small to medium-sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds, can affect the region's quality of supply. In addition, peak electricity demand in Burnt Hill and Swannanoa occurs during summer when the thermal ratings of overhead lines are limited by the higher ambient temperatures.

MainPower's sub-transmission network in the Waimakariri area is supplied from Transpower's Southbrook GXP as indicated in Figure 6.6.

The sub-transmission network is dominated by a large overhead 66 kV ring circuit, serving Burnt Hill and Swannanoa, with a double-circuit 66 kV tower line, which is owned by Transpower, feeding Kaiapoi. The 66 kV Burnt Hill and Swannanoa ring currently operates in an open state and is supplied from Southbrook. Our sub-transmission and distribution networks in the Waimakariri area are predominantly overhead, reflecting the rural nature of the area.

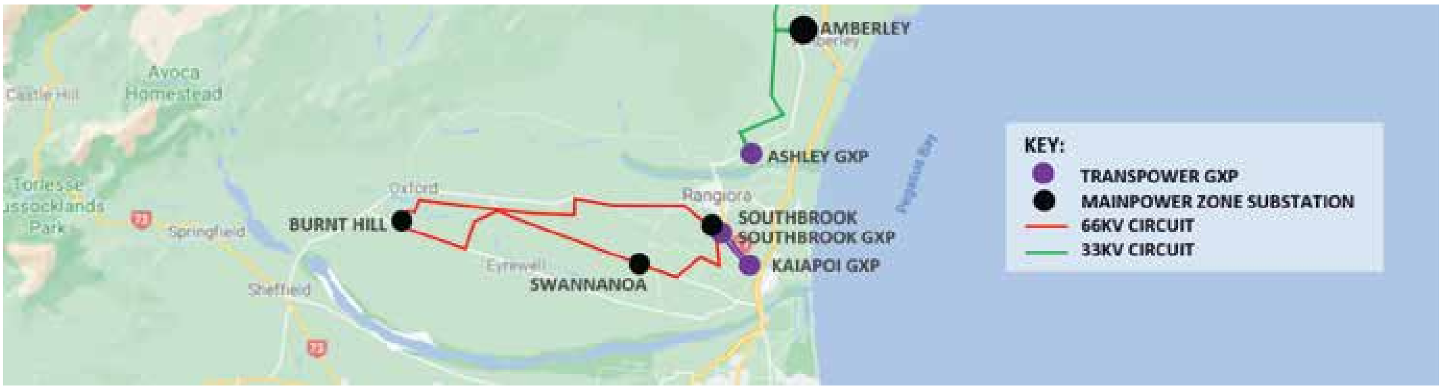


Figure 6.6: Waimakariri region sub-transmission network (existing)

6.8.1.1 Demand forecasts

Demand forecasts for the Waimakariri Zone Substations are shown in Table 6.4.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)									
			FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Ashley 11 kV	A1	40.0	15.0	15.2	15.5	15.8	16.2	16.6	17.1	17.7	18.4	19.2
Burnt Hill	A1	23.0	14.9	15.2	15.5	15.8	16.2	16.6	17.1	17.6	18.3	19.1
Kaiapoi 11 kV	AAA	38.0	31.5	33.0	34.5	36.2	37.9	39.9	42.1	44.7	47.7	51.2
Southbrook	AAA	40.0	39.9	41.6	43.3	45.2	47.3	49.6	52.3	55.4	59.1	63.4
Swannanoa	A1	23.0	16.1	16.4	16.7	17.0	17.4	17.9	18.4	19.0	19.7	20.6

Note: Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

Table 6.4: Waimakariri area network demand forecast

6.8.1.2 Network constraints

Major constraints affecting the Waimakariri area are shown in Table 6.5.

Load Affected	Major Issues	Growth and Security Projects
Ashley GXP	The Ashley GXP has a 'Grid Direct' single major consumer and cannot be restored within 15 seconds.	We recognise this as a gap in the Security of Supply Standard and have discussed and agreed this configuration with the single consumer supplied via this site.
Southbrook, Burnt Hill, Swannanoa and Kaiapoi	Limited ability to achieve Transpower's load requirements during a half-bus outage.	Coldstream Zone Substation programme. Develop long-term 66 kV interconnection capacity between Waipara, Southbrook, and the future Coldstream Zone Substation.
Southbrook and Kaiapoi 11 kV	Forecast to exceed security-of-supply capacity between FY28 and FY30.	Construction of Coldstream Zone Substation planned for FY26–FY29, along with tactical reinforcement projects to allow load transfer to Ashley and Swannanoa.

Table 6.5: Waimakariri area network constraints

6.8.1.3 Major projects

Table 6.6 provides individual summaries of the major growth and security projects planned for the Waimakariri area.

Coldstream 66/11 kV Zone Substation	
Expected Project Timing	FY24, FY26–FY29
Strategic Drivers	System Growth, Quality of Supply – Resilience
Business Case Required?	Yes

Table 6.6: Coldstream 66/11 kV Zone Substation

Residential and commercial growth in the Rangiora, Woodend, Ravenswood and Pegasus areas is driving the need for a new zone substation east of Rangiora. The Coldstream Zone Substation programme incorporates a series of sub-projects to construct 66 kV sub-transmission network and a new Coldstream 66 kV Zone Substation. The overall programme includes:

- **Coldstream 66 kV Sub-transmission Line Design**: Line route detailed design, including easements and consents for a 66 kV overhead line connecting from Ashley GXP to the new Coldstream 66 kV Zone Substation, and from Coldstream Zone Substation to the Southbrook GXP. The design stage will allow construction from Ashley to the Rangiora Woodend Road area and will be timed to provide support at 11 kV to assist with growing loads in Ravenswood and to reduce load on Southbrook Zone Substation. Completion of the second 66 kV circuit from Coldstream to Southbrook GXP will follow construction work on the substation.

- **Ashley GXP to Coldstream 66 kV Sub-transmission Line Build**: These stages construct the Ashley to Coldstream 66 kV sub-transmission line, which will initially operate at 11 kV, providing additional capacity into the Coldstream region until the Coldstream Zone Substation is completed.

- **Coldstream Zone Substation Design and Construction**: This will extend on initial concept studies to deliver a full detailed design, construct the new Coldstream 66 kV Zone Substation and terminate the 66 kV sub-transmission line from Ashley to commission the new zone substation.

- **Southbrook GXP to Coldstream 66 kV Sub-transmission Line Build**: This stage completes the Coldstream Zone Substation programme by constructing the Southbrook to Coldstream 66 kV sub-transmission circuit, providing full N 1 supply to the new Coldstream Zone Substation.

6.8.1.4 Reinforcement projects

MainPower invests in tactical network reinforcement projects to improve network reliability and security of supply, as well as to help defer higher-capital projects. Table 6.7 summarises the reinforcement projects in the Waimakariri area.

Financial Year	Project Title	Description
FY25	Island Road Upgrade	A new feeder for increased capacity in Island Road.
FY25	Kaiapoi K7 Feeder Split	Separate the single K7 feeder into two feeders to improve 11kV capacity and operational flexibility.
FY25	Marsh Road Feeder Creation	A new feeder cable is to be installed from Southbrook Zone Substation to Marsh Road to improve the capacity and reliability to Pegasus and Ravenswood.
FY26	Ashley – Ravenswood Feeders 1 & 2	Multiple network upgrades (cable, RMU and air break switch installations) are to be undertaken to allow the (future) 66 kV line from Ashley GXP Substation to the (future) Coldstream Zone Substation to be used as a temporary 11 kV supply to Ravenswood.
FY26	Mandeville Area Voltage Improvement Stage 1 & 2	Install a regulator and reconductor sections of the line between Kaiapoi and Mandeville to improve the voltages in that area of the network.
FY26	Woodend Network Upgrade	Installation of new cable, RMUs and replacement of a regulator to allow additional capacity for Pegasus and Ravenswood.
FY27	Loburn Regulator Installation	Installation of a new voltage regulator within the Loburn area.
FY27	Fernside Reconfiguration, Swannanoa to SBK	Reconfigure supply to the Fernside area to improve security of supply and reliability after the Southbrook Zone Substation upgrade.
FY27	SW63& SW66 Stage 2	Installation of remote-controlled switches to improve safety and reliability
FY27	Mandeville Area Voltage Improvement Stage 3	Reconductor a section of line between Kaiapoi and Mandeville to improve the voltages in that area of the network.
FY28	East Belt Undergrounding	New feeder cables and RMUs are to be installed between large commercial customers within the Rangiora CBD, which are currently supplied by spur connections.
FY28	Ashley – Leithfield Feeder	A cable is to be installed and line reconductored along Rangiora Leithfield Road to allow additional supply into the Leithfield region, improving security of supply.
FY28	Automate Existing RMUs	Install automation to existing RMUs across MainPower's network to improve remote switching capability.
FY29	Underground 11 kV Lawcocks Road Line	The existing double circuit 11 kV line that extends along Lawcocks Road is to be undergrounded to improve capacity and reduce security of supply risks to Amberley from a single pole fault.
FY29	Amberley Beach Alternative Supply	Installation of a new 11 kV line along Hursley Terrace Road and Crossley Road to improve security of supply between spur lines.
FY29	Birch Hill Link Stage 1	A new line is to be installed and an existing line reconductored along Birch Hill Road to link two spur lines supplied from Burnt Hill and Swannanoa Zone Substations, improving security of supply.
FY30	Barkers Road Links	A new 11 kV overhead line and a switching device are to be installed along Barkers Road to allow for security of supply.
FY30	Communications upgrade for FLISR & Data Retrieval	Installation of Fault Location, Isolation, and Service Restoration (FLISR) and data retrieval equipment for network reliability improvement capability.
FY30	Automate Existing RMUs	Install automation to existing RMUs across MainPower's network to improve remote switching capability.
FY31	Rangiora West RMU Automation and Dynamic Switching Upgrade	Automation of an RMU to ensure rapid switching, improving resilience.
FY31	Kaiapoi 8376 to S11 Link	Create an interconnection between 11 kV feeders in Kaiapoi to increase alternative supply options.
FY32	Birch Hill Link Stage 2	Reconductor existing overhead line to allow additional customers to be supplied via the new connection during outages on the adjacent feeder.
FY32	Connect X53, X52 and X55 spurs	Install new overhead lines and circuit breakers to allow connection of three spur lines close to the Waimakariri River, increasing security of supply.
FY32	Oxford to German Road Link and 2 × Entecs	Link the Ashley Gorge feeder to X57 on German Road to improve security of supply and reliability.
FY33	Communications Upgrade	Upgrade of communications for existing switching devices to allow for the network to rapidly identify and isolate fault locations.
FY33	South Eyre Road Feeder Connections	Installation of additional 11 kV line sections along South Eyre Road to allow the connection of three spur lines, increasing security of supply.

Financial Year	Project Title	Description
FY34	Rangiora Western Overhead Feeder	Build an overhead link down Lehmans Road to strengthen the supply to north-western Rangiora where considerable load growth due to residential subdivisions is expected.
FY34	West Belt Underground	Underground the south end of West Belt to remove ageing overhead assets and improve network connectivity.
FY34	Kaiapoi Stone Street Undergrounding	Underground the existing 11 kV overhead conductor to improve security of supply and reduce risk.
FY34	Burnt Hill X53–X56 Link	Link 22 kV from Thongcastor Road to Harmans Gorge Road via the end of Depot Gorge Road. This requires the conversion of part of Depot Gorge Road to 22 kV and will improve reliability and security of supply.

Table 6.7: Waimakariri area reinforcement projects

6.8.2 Hurunui regional overview

The Hurunui area plan covers the region north of Balcairn to the Conway River, and between the South Island's east coast and the Main Divide. The main towns are Amberley, Cheviot, Hawarden, Culverden, Rotherham, Waiau and Hanmer.

Amberley's location on SH1 and its relative proximity to Christchurch has contributed to its recent residential and commercial growth. The Culverden basin and Cheviot area have seen rapid irrigation and dairy development during the last 20 years, with relatively low residential and general commercial growth. The Waipara area has also had significant vineyard developments established. In the north, Hanmer is a medium-sized tourist destination with steady growth anchored largely around the Hanmer Springs Thermal Pools and Spa complex. Hanmer's network load is dominated by tourist and holiday home activities.

The region is characterised by a mixture of flat, open plains, rolling hills and rugged hill country. South of Amberley, land is used for a range of farming activities, with an increasing number of small to medium-sized lifestyle blocks. Seasonal weather extremes, including snow and strong winds, can affect the region's quality of supply. In addition, electricity demand in the central Culverden basin, Waipara, Cheviot and Parnassus area are summer peaking when the thermal ratings of overhead lines are limited by the higher ambient temperatures. The northern and southern areas are winter peaking.

MainPower's sub-transmission network in the Hurunui area is supplied from Transpower's Waipara and Culverden GXPs as shown in Figure 6.7. The area uses a combination of 66 kV and 33 kV sub-transmission voltages, with our long-term plan to phase out 33 kV. The sub-transmission network consists of a long 66 kV and 33 kV interconnection between Waipara and Culverden GXPs, which supplies the Mackenzies Road, Greta, Cheviot and Parnassus substations in the Hurunui area, as well as the Oaro and Kaikōura/Ludstone Road substations in the Kaikōura area. Hanmer is on a 33 kV spur from the Culverden GXP, while Amberley is tee-connected on a 33 kV circuit from the Waipara GXP to Ashley GXP.

The Kate Valley Landfill site is generating a significant and growing amount of electricity from its landfill gas (currently up to 4 MW). In addition, the neighbouring Mt Cass is forecast to become the site of a large wind farm. Both of these would feed back to the Waipara GXP.

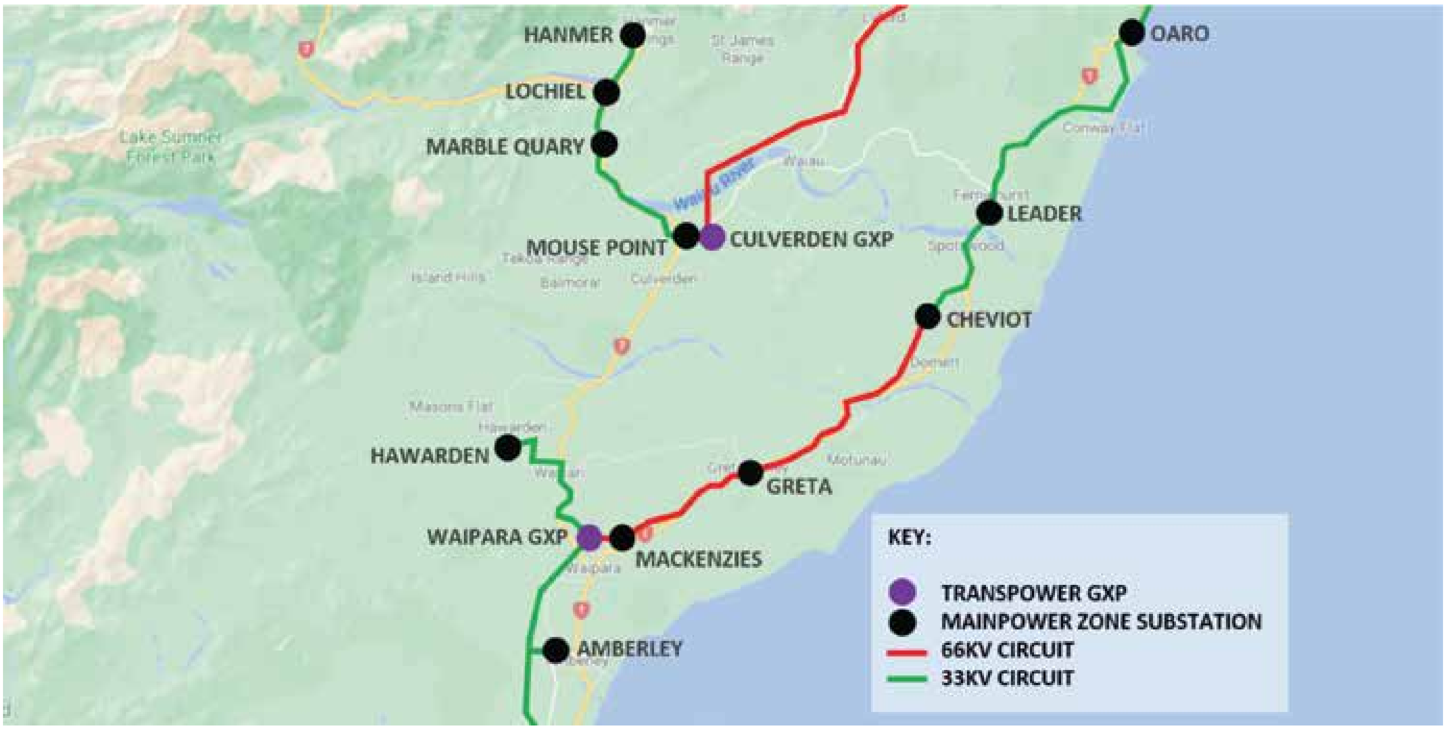


Figure 6.7: Hurunui sub-transmission network (existing)

6.8.2.1 Demand forecasts

Demand forecasts for the Hurunui Zone Substations are shown in Table 6.8.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)									
			FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Amberley	AA	4	6.3	6.7	7.1	7.6	8.1	8.6	9.3	10.0	10.8	11.7
Mackenzies Road	A1	4	2.7	2.8	3.0	3.1	3.2	3.3	3.5	3.6	3.7	3.9
Greta	A1	4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
Cheviot	A1	4	3.5	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.1	4.3
Leader	A1	4	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9
Hawarden	A1	4	3.7	3.8	3.9	4.1	4.2	4.3	4.5	4.7	4.9	5.2
Mouse Point	AA	13	14.9	15.3	15.5	15.8	16.1	16.4	16.7	17.1	17.6	18.0
Marble Point	A2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lochiel	A2	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Hanmer	AA	2.5	5.1	5.3	5.5	5.7	6.0	6.3	6.6	7.0	7.4	7.9

Note: Dark grey shading indicates peak demand exceeds current security-class capacity.

Table 6.8: Hurunui area network demand forecasts

6.8.2.2 Network constraints

Major constraints affecting the Hurunui area are shown in Table 6.9.

Load Affected	Major Issues	Growth and Security Projects
Amberley	Load exceeds security-of-supply class rating (N-1). Peak load cannot be supplied in the event of a transformer or sub-transmission outage.	• Planned load transfer to Mackenzies Road Zone Substation to minimise the capacity shortfall. • Upgrade of Amberley Zone Substation FY24–FY27.
Greta	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• Planned tactical distribution-level reinforcement projects will link the Greta area to the Cheviot Zone Substation to provide switchable backup at 22/11 kV.
Cheviot	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV Sub-transmission Upgrade in FY24–FY26 will increase the capacity of the Leader Zone Substation to supply into the northern Cheviot area during peak summer loads. • The Cheviot area will be linked to the Greta Zone Substation to provide switchable backup at 22/11 kV.
Leader	This is an N security substation and peak load cannot be supplied in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV Sub-transmission Upgrade will increase the capacity of the Leader Zone Substation in FY24–FY26. • There are currently no plans to provide full switchable backup within the planning period.
Hawarden	This is an N security substation and peak load cannot be supplied in the event of a transformer outage. The substation is also supplied from a single 33 kV spur line.	• The Hawarden Zone Substation is planned to be rebuilt as a dual transformer substation in FY31–FY33. • Tactical reinforcement projects will increase load-transfer capacity from Mouse Point, enabling backup for growth and non-irrigation load. Peak load for Hawarden is primarily driven by irrigation load, and we are exploring non-network load management/flexibility options in this area.
Mouse Point	The peak load is above the security-of-supply capacity (N-1). Switching of the 33 kV supply following a 33 kV cable fault is local and would require more than 45 minutes.	• MainPower has installed emergency control on irrigation loads in this region to allow all but irrigation loads to be restored on a single 13 MVA transformer. A spare 8 MVA transformer is held as a backup. We are exploring non-network load management/flexibility options in this area. • Summer cyclic ratings will be explored to maximise the contingency rating of the transformers. • The Mouse Point Zone Substation will be rebuilt in a full N-1 configuration, in FY29–FY31.
Hanmer	The peak load is above the security-of-supply capacity (N-1) of the installed spare transformer. This zone substation is also supplied from a 33 kV radial spur.	• A project is planned to replace the Hanmer Zone Substation with full N-1 configuration, in FY27–FY29. • We are exploring non-network and flexibility options to help manage peak loads and improve security of supply and resilience for the Hanmer region. • The 33 kV line is being upgraded over the period

Table 6.9: Hurunui area network constraints

6.8.2.3 Major projects

The following tables (Table 6.10 to Table 6.12) summarise the major projects (growth and security) planned for the Hurunui area.

Amberley Zone Substation	
Project timing	FY24–FY27
Strategic drivers	System growth, quality of supply, asset replacement and renewal
Business case required?	Yes

Table 6.10: Amberley Zone Substation upgrade

This project involves replacement of the Amberley 33 kV Zone Substation, rebuilding it for future 66/11 kV operation on a new site and eliminating the existing sub-transmission line spur connection. It will be configured as an N-1 substation, will remove capacity and security constraints, and will replace the end-of-life assets. The long-term plan is to convert the 33 kV sub-transmission line to 66 kV from FY34 to FY37. The zone substation project will be staged as follows.

- **Consenting and Detailed Design**: The first stage of this programme is the detailed design for the Zone Substation site, including sub-transmission line terminations provisioned for future 66 kV. Any consenting requirements are also included in this stage.
- **Amberley Zone Substation Build:** This stage constructs the Zone Substation and commissions it to operate at 33 kV until the 66 kV sub-transmission line upgrade project is completed.
- **Waipara–Amberley–Ashley Sub-transmission Line Upgrade: T**his stage completes the Amberley 66/11 kV Zone Substation upgrade programme by upgrading the existing 33 kV sub-transmission line to 66 kV, allowing the zone substation to operate at 66/11 kV (future project expected to occur from FY34 to FY37).

Hanmer Zone Substation	
Project timing	FY27–FY29
Strategic drivers	System growth, security of supply, asset replacement and renewal
Business case required?	Yes

Table 6.11: Hanmer Zone Substation upgrade

The Hanmer Zone Substation does not currently meet MainPower's Security of Supply Standard of restoration within 45 minutes following a single sub-transmission failure. The existing overhead-line structures are approaching end-of-life and need replacement. The cost to replace and maintain the existing sub-transmission line and build a second sub-transmission circuit to achieve the full security of supply is very high; therefore, this programme is targeted at the following.

- **Hanmer sub-transmission line upgrade**: Improve the resilience and reliability of the existing line with stronger conductor and structures. The line route and structure footings will also be reviewed to mitigate the impact of potential natural hazards where possible.
- **Hanmer Zone Substation Replacement**: Hanmer Zone Substation currently operates on N security of supply, with limited alternative (back-up supply). Consented developments will continue to exacerbate this issue. Hanmer Zone Substation assets are also approaching end-of-life and are scheduled for replacement. This project rebuilds the Hanmer Zone Substation to increase capacity into the Hanmer region, provide substation N-1 security of supply and replaces end-of-life assets.

Potential subdivision growth in the Hanmer region may impact on the scope and timing of this project.

Mouse Point Zone Substation	
Expected project timing	FY29–FY31
Strategic drivers	System growth, security of supply, asset replacement and renewal
Business case required?	Yes

Table 6.12: Mouse Point Zone Substation upgrade

The peak load of the Mouse Point Zone Substation exceeds the continuous rating of its firm (N-1) capacity and is approaching the cyclic rating of the transformers. The zone substation assets are also approaching end of life. MainPower is currently investigating relocation of the Mouse Point Zone Substation to the Transpower Culverden GXP site. This upgrade project is to rebuild the zone substation either on or near the Culverden GXP site. The substation will be constructed at 66/22 kV, although initially operated at 33/22 kV. It is forecast that Transpower will replace the 220 kV/33 kV transformers at the GXP with 220/66 kV transformers in the late 2030s. The timing of works will depend on load growth and whether other technologies, such as DG, effectively reduce the region's summer peaks.

MainPower is interested in non-network flexibility solutions that may be able to manage peak load of the Mouse Point Zone Substation and help defer any capacity upgrades.

6.8.2.4 Reinforcement projects

Financial Year	Project Title	Description
FY26	Amberley Reserve Road Link	Construct a new line to supply the rural area north of Amberley independent of the urban supply to improve reliability and capacity for the Amberley urban area.
FY28	Cheviot–Leader Upgrade	The 11 kV conductor between Parnassus and the Waiau East and West Roads is to be upgraded, improving the security of supply for Cheviot and Leader Zone Substations.
FY28	Hawarden–Mouse Point Link Upgrade	A new section of 11 kV line is to be installed between P35–H41 along SH7 just north of the Hurunui River to enable increased remote load-transfer capacity between Hawarden Zone Substation and Culverden (Mouse Point Zone Substation).
FY28	Reinforce P25 South and across the Hurunui River	A new section of overhead line is to be installed between McKays Road and Bishells Road across the Hurunui River, increasing security of supply between spur circuits.
FY29	Greta – Cheviot Upgrade (Stage 1)	An existing section of overhead 11 kV line is to be reconductored and uprated to 22 kV and a 22/11 kV transformer installed to allow a backup supply for Greta Zone Substation and a partial backup supply for Cheviot Zone Substation.
FY30	Greta – Cheviot Upgrade (Stage 2)	An existing 3.5 km section of 11 kV overhead line adjacent to Hurunui Mouth Road and the railway line is to be reconductored, increasing security of supply.
FY30	Greta–Hawarden Link Upgrade	A voltage regulator is to be installed and conductor upgraded in the Scargill Valley to increase transfer capacity between Greta and Waikari (Hawarden Zone Substation).
FY33	Mouse Point Feeder	A new feeder from Mouse Point Zone Substation to the Culverden township will be installed to provide security of supply for the existing Culverden township loads (P25 and P35 feeders) and increase transfer capacity to Hawarden to meet the Security of Supply Standard.

Table 6.13: Hurunui area reinforcement projects

6.8.3 Kaikōura regional overview

The Kaikōura area plan covers the region north of the Conway River to the Puhi Puhi Valley north of Kaikōura, and between the South Island's east coast and the Main Divide. The area extends northwards up the coast to Half Moon Bay. Kaikōura is the main township in the region.

Kaikōura is a significant tourist destination and a key stop-off point on SH1 for people travelling between Blenheim and Christchurch. Like Hanmer, the town is also a popular holiday location, particularly for Canterbury residents. Growth is dependent on the strength of the tourism industry. The area was severely affected by damage in the 2016 Waiau earthquake and the associated access constraints. Future growth is uncertain. Kaikōura's isolated location on SH1 may make it a key charging location for Evs in the future.

The region is characterised by narrow, rocky coastal margins, flat open plains, steep bushy valleys and rugged hill country. The flats are used for a range of farming activities, including dairying, without the intensive irrigation of other areas. Seasonal weather extremes, including snow, strong winds and rain can affect the region's quality of supply and access for repairs. Electricity demand is reasonably flat, with high winter loads balanced by increased visitor numbers in summer. Demand typically peaks on cold holiday weekends.

The Kaikōura area is normally supplied from the Culverden GXP at 66 kV, transitioning to 33 kV at Kaikōura, as shown in Figure 6.8. The small coastal communities south of Peketā are supplied from the 33 kV and 66 kV interconnection between Kaikōura and the Waipara GXP.

Figure 6.8: Kaikōura region sub-transmission network

6.8.3.1 Demand forecasts

Demand forecasts for the Kaikōura Zone Substations are shown in Table 6.14.

Substation	Security Class	Class Capacity (MVA)	Demand Forecast (MVA)									
			FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Ludstone	AA	6.0	5.9	6.0	6.1	6.3	6.4	6.5	6.6	6.7	6.9	7.0
Oaro	A1	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5

Note: Dark grey shading indicates peak demand is forecast to exceed current security-class capacity.

1 We are exploring the use of non-network load management/flexibility options in the Kaikōura area as well as investigating re-rating the transformers using cyclic ratings.

Table 6.14: Kaikōura area network demand forecasts

6.8.3.2 Network constraints

Major constraints affecting the Kaikōura area are provided in Table 6.15.

Load Affected	Major Issues	Growth and Security Projects
Kaikōura township and areas down the Kaikōura Coast to Waipara	Peak load on Ludstone Zone Substation, which supplies the greater Kaikōura region, exceeds the nameplate continuous rating of a single power transformer under N operation.	MainPower is intending to utilise cyclic transformer ratings and load management to manage peak load until a project to rebuild the Ludstone Zone Substation on the Kaikōura 66/33 kV Substation site begins in FY29. A new transformer modelling tool to allow this is currently in development and is expected to be operational in FY25.
	The required 45-minute security-of-supply switching time for a sub-transmission fault cannot be achieved. In addition, the backup N-1 capacity from Waipara GXP has reached full capacity.	The Cheviot–Kaikōura 66 kV Sub-transmission Upgrade Project (FY24–FY25) will upgrade the existing 33 kV sub-transmission system from Cheviot to Kaikōura to 66 kV.

Table 6.15: Kaikōura area network constraints

6.8.3.3 Major projects

Table 6.16 and Table 6.17 summarise the major growth and security projects planned for the Kaikōura area.

MainPower's sub-transmission line between Oaro and Kaikōura, along the Kaikōura coast, was affected by the 2016 Kaikōura earthquake. Short-term repairs were performed on the line section that crosses over the Raramai Tunnel; however, these require review and replacement to provide a long-term resilient solution for this section of the sub-transmission network.

Cheviot to Kaikōura 66 kV Sub-Transmission Upgrade	
Expected Project Timing	FY24–FY25
Strategic Drivers	Security of supply, system growth, asset replacement and renewal
Business Case Required?	Yes

Table 6.16: Cheviot to Oaro sub-transmission line upgrade

The line between Cheviot and Kaikoura is constructed at 66 kV but is currently operating at 33 kV. This project removes the 66/33 kV transition point and completes the sub-transmission line upgrade to operate the full Waipara to Kaikōura line at 66 kV. Land has been purchased for the relocation and rebuild of the end-of-life 33 kV Oaro Zone Substation to a new site. A new 66 kV bay will be constructed at Kaikōura substation to allow two 66 kV circuits into Kaikōura and provide full N-1 sub-transmission line security of supply.

This project also includes the replacement of the sub-transmission line structures that cross the Raramai Tunnel to provide a more resilient solution.

Kaikōura 66 kV Zone Substation	
Expected Project Timing	FY27, FY29–FY31
Strategic Drivers	Security of supply, system growth, asset replacement and renewal
Business Case Required?	Yes

Table 6.17: Kaikōura 66 kV Zone Substation

This project involves replacement of Ludstone 33 kV Zone Substation, relocating the zone substation to MainPower's existing Kaikōura substation site and decommissioning the old Ludstone site. Existing 66 kV infrastructure at the Kaikōura substation site will be used, with two new 66/11 kV transformers installed and an 11 kV switch room constructed. The zone substation project will be staged as follows.

- **Consenting and Detailed Design**: The first stage of this programme is the detailed design for the Zone Substation site, including sub-transmission line terminations and integration into the 11 kV distribution network. Any consenting requirements are also included in this stage.
- **Kaikōura Zone Substation Build**: This stage constructs and commissions the Zone Substation at 66/11 kV.

6.8.3.4 Reinforcement Projects

Financial Year	Project Title	Description
FY25	Kaikōura Town Security Upgrades	The existing overhead double circuit line supplying the Kaikōura township is to be undergrounded to provide security of supply and more efficient load transfer between the two main feeders.
FY27	Beach Road Cable Installation	An existing section of 11 kV cable is to be replaced along Beach Road in Kaikōura to ensure capacity for future demand requirements for customers north of Ludstone Road.
FY27	Seaview Feeder Extension	A new 11 kV cable is to be installed extending south along Mt Fyffe Road and into the Seaview subdivision to provide additional capacity and security of supply.
FY31	Ocean Ridge Feeder Upgrade	A new cable is to be installed extending south from the future Kaikōura Zone Substations along Mt Fyffe Road towards SH1, allowing connection with an existing feeder, improving capacity and security of supply to the Ocean Ridge subdivision.
FY31	North Beach Road Feeder	A new overhead 11 kV overhead line is to be constructed along Rorrisons Road, and the existing overhead line along Hawthorne Road is to be reconductored to provide additional capacity for the existing 11 kV line on SH1 north of Kaikōura.
FY32	North Kaikōura Feeder Cable to support SH1 and U42	A new feeder cable is to be installed along SH1 north from Hawthorne Road to Mills Road to allow greater security of supply for the North Kaikōura region.
FY33	Northern Kaikōura Reconfiguration	New 11 kV overhead line sections are to be constructed in the area north of Kaikōura to allow alternative supply routes and increase security of supply.

Table 6.18: Kaikōura region reinforcement projects

6.9 Network development programme summary

An overall summary of the major, reinforcement and GXP projects for the 10-year planning period across all planning regions is presented in Figure 6.9, Table 6.19 and Table 6.20. Several large projects create a "lumpy" major project expenditure, balanced by activity in minor works.

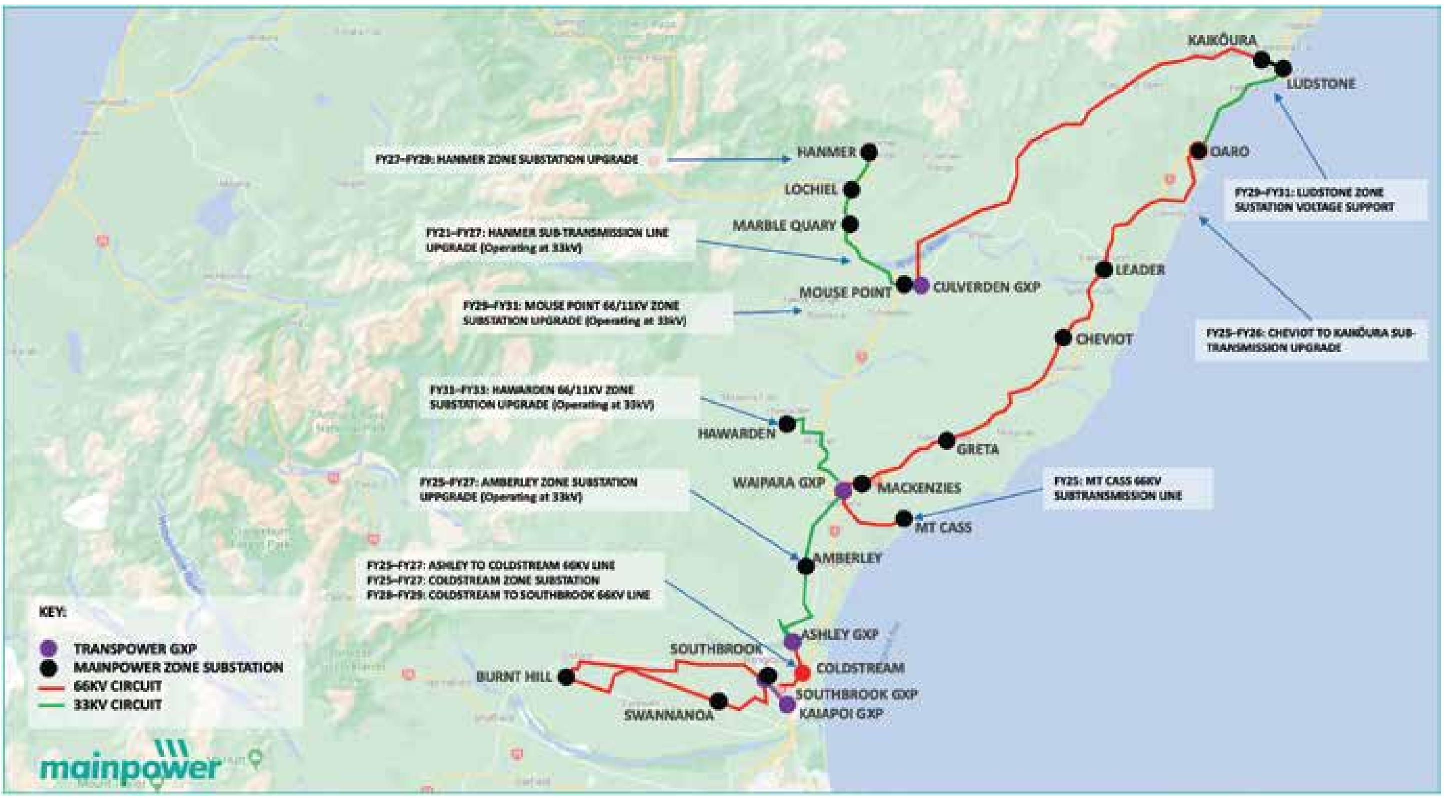


Figure 6.9: 10-year AMP projects

6.9.1 Major Projects Summary

Project/Programme	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Cheviot-Kaikōura 66 kV Subtransmission Optimisation	■	■								
Amberley Zone Substation Upgrade	■	■	■							
Coldstream Zone Substation	■	■	■							
Ashley-Coldstream-Southbrook 66 kV	■	■	■	■	■					
Hanmer Subtransmission & Zone Substation Upgrade	■	■	■	■	■					
Kaikōura Zone Substation			■		■	■	■			
Mouse Point Zone Substation Upgrade					■	■	■			
Hawarden Zone Substation Upgrade							■	■	■	
Amberley 66 kV Conversion										■
MAJOR PROJECT EXPENDITURE ($000)	**12,462**	**13,768**	**13,248**	**7,200**	**5,190**	**9,810**	**5,135**	**3,250**	**3,250**	**1,500**

Table 6.19: Major projects programme summary

6.9.2 Reinforcement projects summary

Project/Programme	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Island Road Upgrade	■									
Kaiapoi K7 Feeder Split	■									
Marsh Road Feeder Creation	■									
Kaikōura Town Feeder Upgrades	■									
Ashley to Ravenswood Feeders 1/2		■								
Mandeville Area Voltage Improvement Stage1/2		■								
Amberley Reserve Road Link		■								
Woodend Network Upgrade		■								
Beach Road Cable Installation			■							
U102 Seaview Feeder Extension			■							
Loburn Regulator Installation			■							
Fernside Reconfiguration. Swannanoa to SBK			■							
SW63& SW66 Stage2			■							
Mandeville Area Voltage Improvement Stage3			■							
East Belt Undergrounding				■						
Cheviot to Leader Upgrade				■						
Ashley to Leithfield Feeder				■						
Reinforce P35 to H41 along SH7				■						
Reinforce P25 South across the Hurunui River				■						
Automate Existing RMUs				■						
Underground Double Circuit Line Lawcocks Rd					■					
Cheviot to Greta Upgrade Stage1					■					
Amberley Beach Alternative Supply					■					
Birch Hill Link Stage 1					■					
Automate Existing RMUs					■					
Barkers Road Links						■				
Greta to Cheviot Upgrade Stage2						■				
Greta to Hawarden Upgrade 1 MW						■				
Communications upgrade fH1or FLISR & Data Retrieval						■				
Automate Existing RMUs						■				
Rangiora West RMU Automation/Dynamic Switching							■			
Kaiapoi 8376 to S11 Link							■			
Ocean Ridge Feeder Kaikōura							■			
North Beach Road Feeder Kaikōura							■			
Birch Hill Link Stage2								■		
Connect X52, X53, and X55 Spurs Waimakariri								■		
North Kaikōura Feeder Cable SH1 & U42								■		
Oxford German Road Link and Entecs								■		
Mouse Point Cable Feeder Stage 1 & 2									■	
South Eyre Road Feeder Connections									■	
Northern Kaikōura Reconfiguration									■	
Rangora Western Overhead Feeder										■
West Belt Undergrounding										■
Kaiapoi Stone Street Undergrounding										■
Burnt Hill X53-X56										■

Project/Programme	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
West Belt Undergrounding										
Kaiapoi Stone Street Undergrounding										
Burnt Hill X53-X56										
Early Works Budget										
Network Automation Switches/Line Circuit Breakers										
Network Intelligence and Monitoring										
Unscheduled Reinforcement										
REINFORCEMENT EXPENDITURE ($000)	**3,233**	**3,241**	**2,768**	**2,624**	**2,662**	**2,382**	**1,210**	**1,979**	**3,154**	**2,967**

Table 6.20: Reinforcement projects budget summary

6.9.3 Alternatives and deferred investment

Projects presented within the AMP are subjected to internal approval through MainPower's business case approval process. Part of the approval process includes evaluating the projects against non-network alternatives, demand-side management and deferral.
We are actively exploring use of non-network solutions, such as flexibility services, during our project evaluation and options analysis stage to understand all viable cost-effective solutions to network constraints to ensure we are investing in the lowest-cost viable option for consumers.

6.10 Distributed generation policies

Our policies on DG are located on our website (mainpower.co.nz/get-connected). These set out the requirements for connecting DG (of less than 10 kW and greater than 10 kW) and general safety requirements. We also comply with Part 6 of the Electricity Industry Participation Code in this respect.

6.11 Uneconomic lines

The remote nature of parts of our network results in network assets that test the bounds of economic investment. As part of our network development-planning processes, we identify remote uneconomic supplies and explore, through a consultation process with consumers and market participants, alternative solutions for supplying these locations when the present assets are due for replacement.

In this reporting period, MainPower intends to identify sub-economic lines and facilitate a market response through a Request for Price process to identify non-network solutions that are more sustainable, with the intent to decommission sub-economic lines.

6.12 Non-network solutions

6.12.1 Load control

We use ripple control to manage peak demand, alleviate network constraints, defer capital investment and reduce transmission charges. Irrigation load can also be controlled during contingencies or at times of system constraints. Other initiatives under consideration are tariff restructuring to encourage night load.

The introduction of the Upper South Island Load Control system has resulted in a flat load profile for the upper South Island transmission system. Additional controls are being used to ensure that individual GXP and zone substation peaks are managed. In particular, the Amberley and Ludstone Zone Substation loads are actively managed through winter peak periods to maintain security levels (to achieve N-1 loading whenever possible). The Kaikōura load is also controlled during maintenance outages on the Culverden–Kaikōura 66 kV line. At these times, our 66 kV/33 kV coastal backup line is unable to transmit the normal daily peaks.

6.12.2 Flexibility services

Under MainPower's Network Transformation Plan, there is a workstream to develop a Demand-Side Management strategy that will describe:

- MainPower's network role in flexibility
- how market responses may be contracted in the future to provide for demand-side management beyond 300 Hz ripple control
- how to best promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

6.12.3 Distributed energy resources

Aligned with MainPower's Demand-Side Management scheme, "non-network" solutions such as distributed energy resources (solar energy, energy storage, energy efficiency) can help to offset or delay network growth expenditure.

The Amuri area has already been identified as having demand exceeding MainPower's Security of Supply Standard, and the deployment of renewable resources could offset this constraint.

In this reporting period, MainPower intends to facilitate a market response through a Request for Price process to identify non-network solutions that are more sustainable, with the intent to alleviate security-of-supply risk in the Amuri area.

7. MAINPOWER'S ASSETS

This section provides an overview of MainPower's lifecycle asset management approach for our asset portfolio. Our whole-of-life approach is governed by the Asset Management Policy outlined in 2.3.3 of this document.

We recognise the need to migrate from traditional, age-based replacement and reactive renewals of assets to a holistic approach to portfolio management. We have implemented a forecasting method of asset replacement that is more prescribed through the adoption of the EEA Asset Health Indicator Guide to quantify and inform our replacements. The models utilise condition data collected from inspections and maintenance programmes, engineering expertise, and asset information to optimise replacement. We consider this planned approach more sustainable for managing work programmes, as well as more effective in reducing outages and optimising our asset portfolios. In 2021 we started the journey to further improve on this by initiating a project to implement CBRM models and adopt the EEA Asset Criticality Guide.

Our asset management drivers are informed by several reviews and consumer consultations. This includes the service-level requirements determined through consumer engagement, environmental initiatives, compliance requirements and health and safety considerations.

MainPower's network assets, discussed in the next section and shown in Table 7.1, are grouped into eight portfolios to reflect the way we manage these assets.

7.1 Asset Portfolio

Asset portfolio management is an integral part of MainPower's Asset Management System. It defines the maintenance and renewal programmes for each of the asset fleets to help achieve our asset management objectives. Our goal is to deliver acceptable electricity distribution network service levels, ensure assets are safe and fit for purpose, and minimise the total cost of ownership.

Asset Portfolio	Asset Fleet
Overhead Lines	Poles and pole structures
	Conductors
Switchgear	Circuit breakers, reclosers and sectionalisers
	Ring main units (RMUs)
	Air break switches
	Low-voltage switchgear
Transformers	Zone transformer
	Ground-mounted distribution transformers
	Pole-mounted distribution transformers
	Regulators
Zone Substations	Zone substations
	Switching substations
Underground Assets	Low-voltage underground cables
	High-voltage underground cables
	Low-voltage service boxes
	Low-voltage link boxes
Vegetation Management	Vegetation

Asset Portfolio	Asset Fleet
Secondary Systems	DC systems
	Protection systems
	Earthing systems
	Communications/SCADA
	Load control/ripple plant
Property	Electricity distribution network buildings – distribution kiosks
	Non-electricity distribution network buildings

Table 7.1: Portfolio and asset fleet mapping

For each asset portfolio, we outline the key information that informs our asset management decisions. The key points covered are:

- high-level objectives
- fleet statistics, including asset quantities and age profiles
- fleet health, condition, failure modes and risks
- preventative maintenance and inspection tasks
- replacement (renewal) strategies.

7.2 Overhead lines

MainPower's overhead electricity distribution network has approximately 56,000 poles in service, carrying over 4,000 km of high-and low-voltage overhead conductor. Figure 7.1 shows the MainPower distribution network, giving an overall geographic view

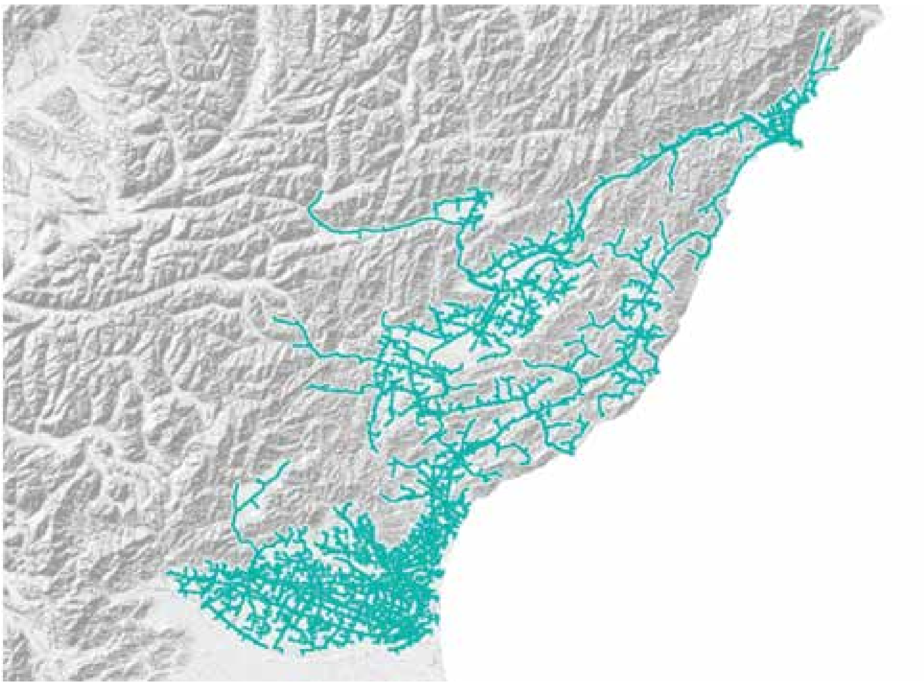


Figure 7.1: MainPower's electricity distribution network's geographical distribution

MainPower's pole inspection and renewal programme aims to proactively minimise the risks from pole failures while balancing cost. As most of our overhead electricity distribution network is accessible to the public, managing our overhead structure assets is a key priority to help ensure public safety.

7.2.1 Poles and pole structures

MainPower has a large range of pole types, including:

- Hardwood (pre mid-1970s);
- Larch poles impregnated with creosote (late 1950s to 1960s);
- Treated pine (post mid-1970s)
- Concrete (post 1960s).

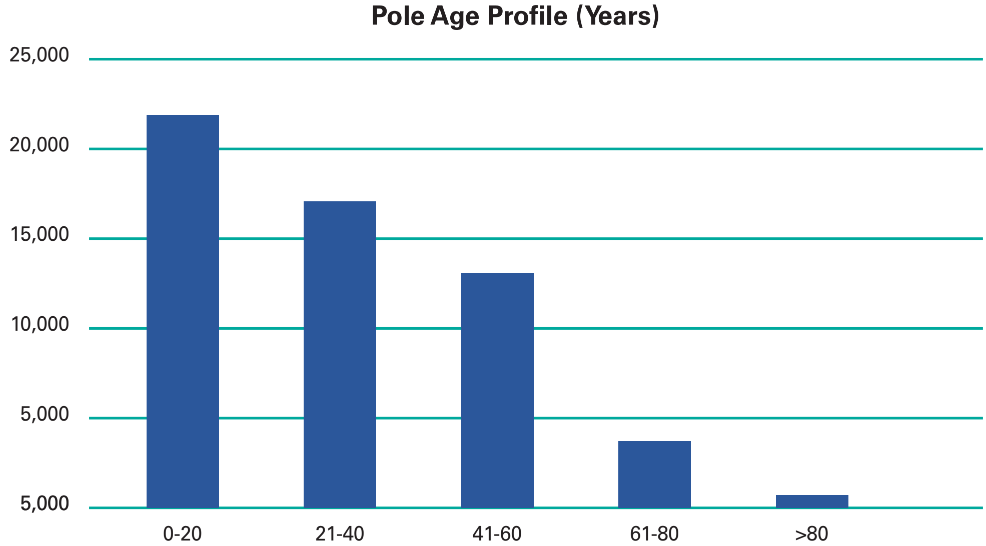


Figure 7.2: Pole age profile

The main pole types used today are H5-treated radiata pine and pre-stressed concrete.

There are approximately 9,800 concrete poles in use on the network today, including reinforced and pre-stressed concrete. Reinforced concrete poles contain reinforcing steel bars covered by concrete; these were used regularly from the 1960s to 1980s. Reinforced concrete poles were produced by many different manufacturers, resulting in differences in design, manufacturing standards and material quality. This has caused differing lifecycle performances, especially in our coastal areas. Most new poles installed today are pre-stressed and are designed and manufactured to meet stringent structural standards, with a design life of 80 years.

7.2.1.1 Maintenance

Maintenance is based on a condition-based assessment carried out on a five-year rotation. The inspections are governed by MainPower's Overhead Inspection and Maintenance Standard, MPNZ 393S049. The inspections cover pole condition and pole attachments such as crossarms, insulators and conductors. The introduction of CBRM has motivated us to review further our pole-testing and data collection methodology to ensure it aligns with CBRM and is in line with industry standards.

In 2022, MainPower invested in a LiDAR capture survey of its entire overhead network, which was completed in August 2022. This LiDAR data has been successfully ingested into Neara, a design and analytics web-based electric utility software platform. Neara then provides MainPower with a 3D dynamic virtual network representation that will allow us to leverage accurate, up-to-date data for assessment of network clearances, identification of defects, and to model environmental scenarios to gauge network resilience. The LiDAR survey will also enable MainPower to transition to aerial-based inspection of overhead assets and the future utilisation of AI for lifecycle decision making and defect management.

A summary of the overhead inspection and maintenance programme, including crossarms and conductors, is provided in Table 7.2.

7.2.1.2 Replacement and disposal

MainPower's existing pole replacement programme is based on a rudimentary age-based condition assessment from pole data collected during the overhead five-yearly inspection cycle. However, with the introduction of CBRM, MainPower will be able to leverage existing data to create actionable information and transition us from age-based to risk-based replacement to improve performance and/or reduce expenditure. Pole replacements are also triggered by the need to upgrade conductors because of condition or capacity, or to improve the environmental resilience of the line structure. As part of conductor upgrade projects, we identify poles that are in poor condition and coordinate their replacement alongside the conductor upgrade to ensure efficient delivery.

7.2.2 Crossarms and insulators

Crossarms support and space the insulators that support the conductor on an overhead-line structure. A crossarm assembly is made of one or more crossarms and a range of subcomponents, such as insulators, high-voltage fuses, surge arrestors, armour rods, binders and jumpers, and arm straps. MainPower uses hardwood timber crossarms that have a nominal asset life of 35 years, and insulators including porcelain, glass and polymer types.

Based on ongoing monitoring, the number of defects of pole-top equipment is found to be increasing steadily, in part due to the increased number of ageing assets, resulting in equipment that is more susceptible to rot and electrical tracking.

7.2.2.1 Maintenance

Inspection and maintenance of crossarms is included in MainPower's Overhead Inspection and Maintenance Standard, MPNZ 393S049, summarised in Table 7.2. Thermal imaging and acoustic testing are currently being investigated, to consider incorporating them into the inspection. We are changing our approach to asset inspections, introducing aerial surveys to increase efficiency and quality. This will enhance our asset replacement decision making. The introduction of CBRM modelling of pole structures, crossarms and conductors will allow us to make full use of aerial inspection data to inform replacement decisions.

To minimise the steady increase of the defects of pole-top equipment, a line-tightening programme is initiated to reduce any potential increase of defective failures.

7.2.2.2 Replacement and Disposal

A pole-top equipment replacement is initiated to address the potential fire risk due to failure. The programme is delivered to replace them individually and in conjunction with the pole replacement programme, through either coordinating works during outages, or replacing entire structures if required because of a combination of poor-condition elements.

7.2.3 Conductors

MainPower has a wide range of conductor types spread over three main categories:

- Sub-transmission overhead conductors
- High-voltage distribution overhead conductors
- Low-voltage overhead conductors.

The type of conductor used is influenced by economic, location, environmental and performance factors. Owing to the rural nature of our network, overhead conductors are a significant component, and we are working to better understand this asset fleet and its end-of-life condition indicators.

Many rural areas still have old bare or covered copper conductor in service. Covered copper conductor in some areas is starting to show signs of insulation peeling and fraying. There are also sections where the conductor has been re-joined over the years, using "Sleeves", "Fargos" or "Twist Joints".

7.2.3.1 Maintenance

Inspection and maintenance of conductors is included in MainPower's Overhead Inspection and Maintenance Standard, MPNZ 393S049, as shown in Table 7.2.

7.2.3.2 Replacement and disposal

MainPower does not currently have a scheduled replacement programme in place for conductors; however, with the introduction of a CBRM conductor model, we will look at leveraging existing conductor condition assessment data and identify relevant data for future capture allowing refinement of our conductor CBRM model. The conductor CBRM model will enable MainPower to develop and justify our conductor replacement planning expenditure technically and economically. MainPower's overhead inspection and maintenance is summarised in Table 7.2 for poles, conductors, crossarms and line hardware.

Component	Maintenance/Renewal Category	Action
Poles	Asset inspection/condition assessment	5-yearly pole test and overhead inspection programme
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Condition-based, from data collected during the inspection programme
Conductors	Asset inspection/condition assessment	5-yearly overhead inspection for corrosion, binder fatigue and incorrect sag
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data
Crossarms	Asset inspection/condition assessment	5-yearly inspection as part of the overhead inspection programme
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data from the inspection programme
Line Hardware	Asset inspection/condition assessment	5-yearly inspection as part of the overhead inspection programme
	Routine and preventative	Maintenance based on condition assessment data
	Refurbishment and renewal	Replacement based on condition assessment data

Table 7.2: Overhead electricity distribution network inspection matrix

7.3 Switchgear

Switchgear is used for switching, isolating and protecting the electricity distribution network. This section covers:

- circuit breakers, reclosers and sectionalisers
- RMUs
- pole-mounted switches
- low-voltage switchgear.

7.3.1 Circuit breakers, reclosers and sectionalisers

MainPower's circuit breakers, reclosers and sectionalisers provide protection and the isolation of faults, allowing safe and efficient switching of the electricity network. Circuit breakers are generally located at zone substations. Reclosers and sectionalisers are located on overhead-line structures.

Figure 7.3 shows the number and age of circuit breakers, reclosers and sectionalisers (including spares).

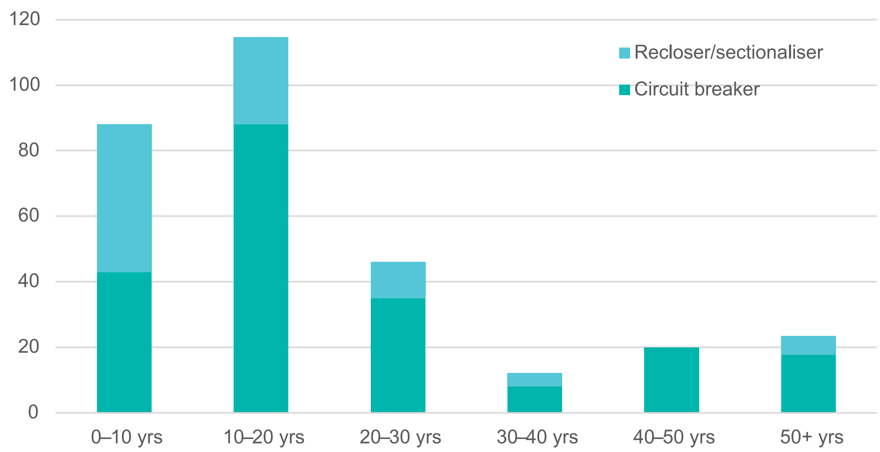


Figure 7.3: Switchgear age profile

MainPower's older circuit breakers are predominantly oil filled (bulk or minimum oil). Circuit breakers that are 25 years old and younger generally use gas or a vacuum as the interruption medium and insulation. A model based upon the EEA Asset Health Indicator Guide has been developed for all circuit breakers (excluding reclosers and sectionalises), shown in Figure 7.3.

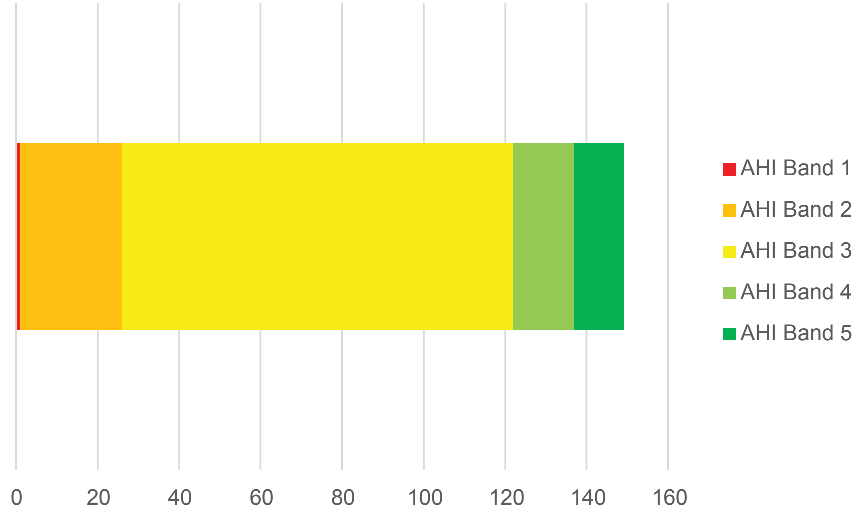


Figure 7.4: Circuit breaker current asset health profile

The general guide is that:

- AHI Band 1 is at end of serviceable life and immediate intervention is required
- AHI Band 2 likely requires intervention as end-of-life drivers for replacement are present
- AHI Bands 3–5 indicate good condition but still require regular inspection and maintenance.

7.3.1.1 Maintenance

Routine maintenance is important to ensure satisfactory operation of the switchgear throughout its intended serviceable life. Maintenance involves visual inspections to identify units or structures in poor condition, partial discharge and infrared testing to locate units showing signs of deterioration, and full servicing to ensure satisfactory operation of the equipment.

Siemens Fusesaver sectionalisers are also interrogated, via a Bluetooth connection, for information that includes the state of the internal battery and operation count. Table 7.3 summarises the maintenance frequencies for the different types of switchgear.

Type	Frequency
Circuit breakers	• 3 monthly – Visual inspection • 12 monthly – Partial discharge test + infrared test • 3 yearly – Full service (including clean and oil change if required)
Reclosers and sectionalisers (sub-transmission and distribution)	• 12 monthly – Visual inspection • 2.5 yearly – Infrared scan • 10 yearly – Full service (including clean and oil change if required)

Table 7.3: Switchgear maintenance programme summary

7.3.1.2 Replacement and Disposal

Scheduled replacement is based on asset condition and health, informed by MainPower's AHI model.
This is combined with an asset criticality score and ranks the switchgear in order of priority for replacement.
As a result, MainPower's replacement programme for this asset fleet is focused on older oil-filled switchgear, including South Wales circuit breakers and McGraw Edison reclosers. The Nulec units installed on the network have also been prioritised for replacement due to their upcoming obsolescence.

MainPower's key drivers for this replacement programme are minimising risk, improving network reliability, obsolescence, and operational control of the network. We expect unscheduled replacement works to reduce during the next five years as the maintenance and replacement programme matures.

7.3.2 Ring main units

As shown in Figure 7.6, MainPower's RMUs are:

- cast resin (1960s through to early 2000s)
- oil filled (1960s through to early 2000s)
- vacuum or SF6 (post-2000).

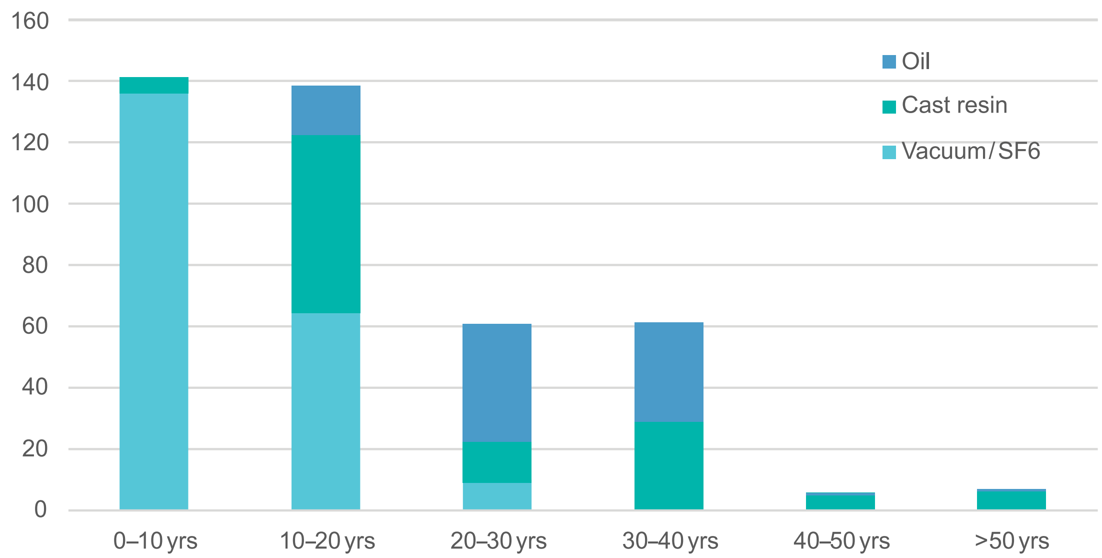


Figure 7.5: RMU quantities and age profiles

MainPower's older oil-filled RMUs currently have operational restrictions to reduce any inherent risk, and our replacement programme is targeting these assets to remove them from the network. A MainPower RMU asset health model has been developed to help optimise the replacement and maintenance programme for this asset fleet, as shown in Figure 7.6.

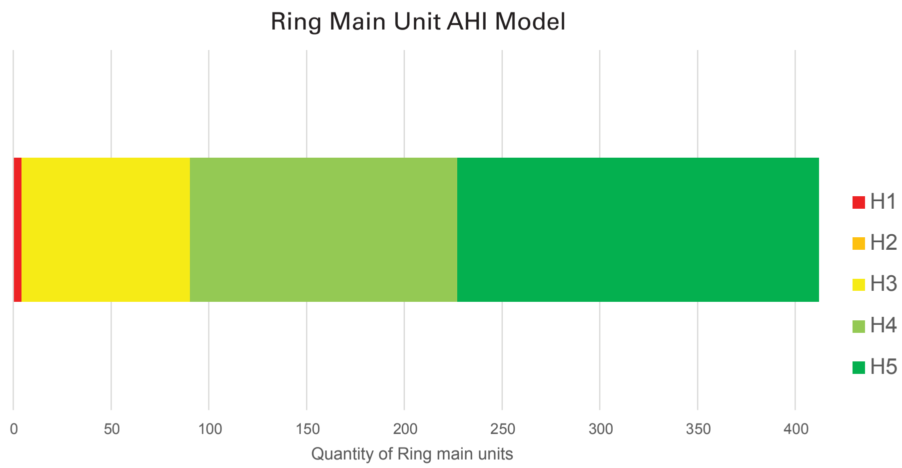


Figure 7.6: RMU current asset health

7.3.2.1 Maintenance

Regular maintenance is important to ensure the safe and efficient operation of RMUs. Oil-filled and cast resin types are typically more expensive to maintain and service than the vacuum and SF6 types. SF6 units are checked regularly for gas levels to ensure there are no gas leaks.

Table 7.4 shows the maintenance types and frequencies for the different types of units.

Type	Frequency
Oil filled	• 12 monthly – Inspection + partial discharge test • 5 yearly – Service (including oil change) + infrared test
Cast resin	• 12 monthly – Inspection + partial discharge test + infrared test • 5 yearly – Service (including a full clean of contacts)
Vacuum/SF6	• 12 monthly – Inspection + partial discharge test • 5 yearly – Service + infrared test
All	• Real time – Indication including SF6 gas pressure alarm, operation count (where available)

Table 7.4: Switchgear inspection and maintenance summary

7.3.2.2 Replacement and Disposal

MainPower's RMU replacement programme is targeting the units with a low health score. In the medium to long term, it is expected that approximately 10 units will be replaced per year.

7.3.3 Pole-mounted switches

Pole-mounted switches are used from 11 kV up to 66 kV across the MainPower network, with an extensive range of makes and models, namely:

- Canterbury Engineering Type (1950s to 1980s)
- Dulmison, Electropar and ABB (1980s to present)
- Allied ABS (present)
- Entec Fully Enclosed Vacuum Break (present).

Most historical pole-mounted switches are of the air break type, with an increasing number of vacuum switches. The vacuum break switches have a good load-breaking ability, in addition to providing remote control and indication, helping to improve network visibility and providing opportunity for increased automation. Figure 7.8 gives the age profile of the pole-mounted switches.

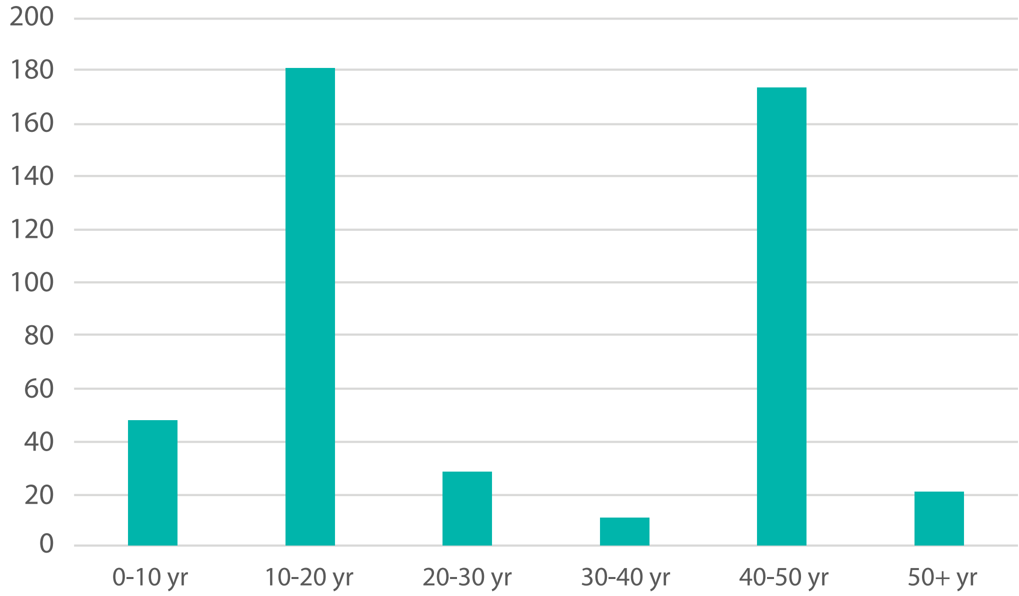


Figure 7.7: Pole-mounted switch quantities and age profiles

The mechanisms on air break switches are prone to sticking or seizing if not operated or maintained for extended periods of time. This can cause unexpected delays during operation and further damage to the switch if it does not open or close correctly. This is addressed through a regular inspection and maintenance programme, as outlined below.

7.3.3.1 Maintenance

Pole-mounted switches are maintained every five years. This includes a condition assessment of the switch, which is combined with inspection and asset data to inform the replacement programme (see Table 7.5).

Type	Frequency
Pole-mounted switches	5 yearly – Visual inspection + full service + infrared test to identify hotspots

Table 7.5: Pole-mounted switchgear inspection and maintenance summary

7.3.3.2 Replacement and Disposal

A replacement programme is in place to replace the older switches, prioritised through asset inspection data and observed asset reliability information. The implementation of the ADMS will enable more accurate collection of switch operation frequency and condition data from visual inspections, which will feed into an asset health replacement model to better prioritise the programme.

7.3.4 Low-voltage switchgear

There are a range of different types of low-voltage switchgear on MainPower's network, the main types being:

- exposed (skeleton) panels
- D&S fused switches
- Terasaki circuit breakers
- ABB Fastline (SLK) fuse gear
- DIN-style fused switches (current type for new installations).

There is currently limited data in our asset database regarding quantities and types of low-voltage switchgear. MainPower has initiated an inspection programme to collect asset attribute and condition information. The known issues for the switchgear types outlined above are shown in Table 7.6.

Low-Voltage Switchgear Type	Known Issues/Defects
Exposed (skeleton) panels	• Porcelain fuse handles, which can be the cause of localised heating • Exposed bus-work
D&S fused switches	• Incomplete switching risk
Terasaki circuit breakers	• Incomplete switching risk
ABB Fastline (SLK) fuse gear	• Localised heating due to poor cable terminations
DIN-style fused switches	• Localised heating due to poor cable or fuse terminations

Table 7.6: Low-voltage switchgear common defects

7.3.4.1 Maintenance

A visual inspection every 12 months is used to identify any hotspots and units in poor condition, as well as operational issues (see Table 7.). Any defects are investigated, with the condition and criticality of the switchgear used to either prioritise corrective maintenance or schedule replacement.

Type	Frequency
Low-voltage switchgear	12 monthly – Visual inspection + infrared scan + condition assessment

Table 7.7: Low-voltage switchgear inspection summary

7.3.4.2 Replacement and Disposal

The units most likely to be prioritised for replacement will be the exposed panels, D&S fused switches and Terasaki circuit breakers, owing to their issues. The replacements are often combined with RMU maintenance or replacement to reduce the number of outages.

7.4 Transformers

The sub-categories and quantities of MainPower's transformers are summarised in Table 7.8.

Transformer Fleet	Quantity
Power transformers	32
Distribution transformers	8,937
Voltage regulators	31

Table 7.8: MainPower's transformers

7.4.1 Power Transformers

MainPower's zone substation power transformers transform sub-transmission voltages of 66 kV or 33 kV down to distribution voltages of 11 kV, 22 kV or 400 V. Their power ratings range from 0.3 kVA for isolated rural supplies up to 40 MVA within the densely populated parts of the network. MainPower also has five power transformers held as strategic spares. These are surplus units, typically made available from network upgrades, and are held to support network resilience and emergency responses.

MainPower uses transformer condition analysis and diagnostic tests to optimise management of its power transformer fleet. The age profile of the in-service transformers is shown in Figure 7.9. The power transformer fleet has a typical nominal life of 45 years; however, this can vary significantly, depending on the load and operating conditions.

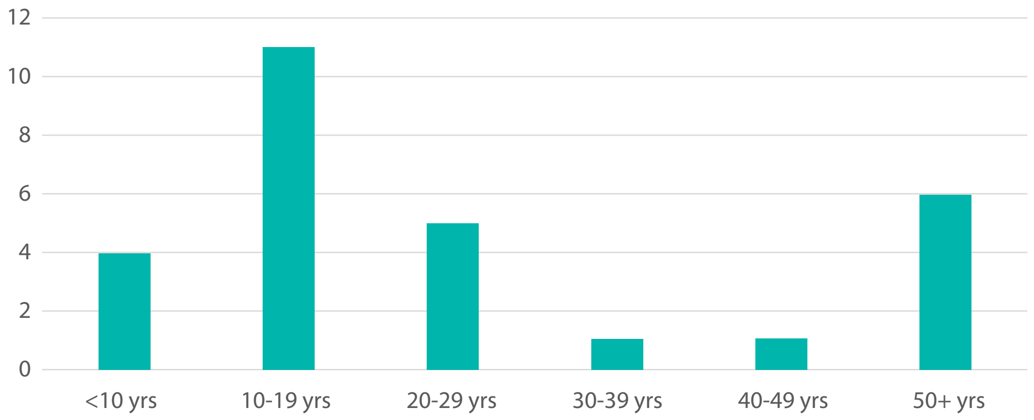


Figure 7.8: Power transformer age profile

The power transformer fleet is managed using MainPower's Power Transformer AHI model. While the model was improved in 2019, resulting in a realignment of some transformers across categories, the overall asset fleet health numbers have remained largely unchanged relative to their condition (see Figure 7.10).

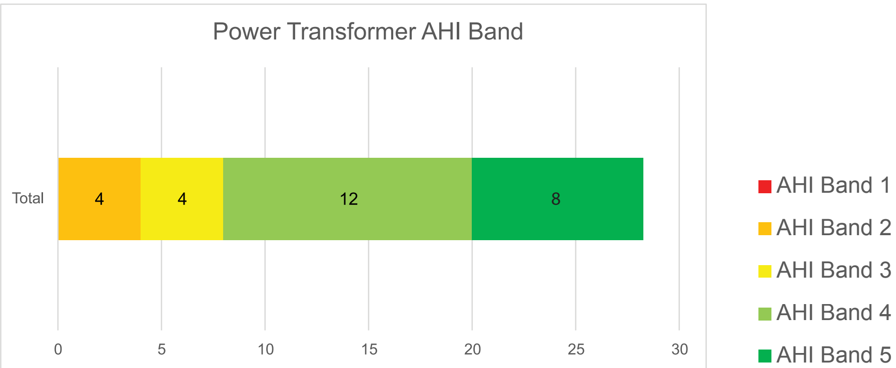


Figure 7.9: Power transformer current asset health

Four of the units with the lowest AHI scores are in the 51–60-year age bracket and have end-of-life indicators showing they are likely to have less than 10 years of life remaining. The other low-scoring unit on the AHI model is in the 41–50-year age bracket. As the remaining units are showing no major defects and are ageing in accordance with their typical lifespans and loadings, much of the replacement will be undertaken as part of a major project.

7.4.1.1 Maintenance

Power transformers are frequently inspected as part of MainPower's three-monthly zone substation inspections, in addition to specific diagnostic testing (see Table 7.9). Dissolved gas analysis is carried out annually, with the strategic spare transformers included in the annual dissolved gas analysis to check their ongoing suitability for service.

Type	Frequency
Power transformers	3 monthly – Visual inspection as part of zone substation inspection schedule
	12 monthly – Dissolved gas analysis
	12 monthly – Thermographic and acoustic partial discharge tests
	5 yearly – Major service, including tap-changer service (some tap changers are on a 3-year cycle), electrical testing of transformer and accessories

Table 7.9: Power transformer inspection and maintenance summary

Oil treatment for moisture and acidity have been carried out historically, and this has been found to affect the chemical tracers for ageing. This was suspended in 2019 to enable dissolved gas analysis, which is more accurate.

7.4.1.2 Replacement and disposal

No immediate replacements are planned for the current financial year. Close monitoring of the ageing trends and paper strength on the three units showing end-of-life indicators is continuing. The timing for replacement will be coordinated with planned 66 kV network upgrades to maximise the asset life and optimise investment.

7.4.2 Distribution transformers

MainPower has more than 8,300 distribution transformers in service, with approximately 85% pole mounted and the remaining units ground mounted either in kiosks or as stand-alone units. These transformers supply end users with single-phase 230 V or three-phase 400 V. The age profile of these is shown in Figure 7.11.

Typical failure modes that drive distribution transformer replacement are:

- oil leaks
- significant rust
- electrical failure/insulation breakdown.

Figure 7.10: Distribution transformer age profile

7.4.3 Ground-mounted distribution transformers

MainPower operates approximately 800 ground-mounted distribution transformers. All units are mineral-oil filled. The ratings, quantities and age profiles are summarised in Table 7. and Figure 7.12.

Rating	Number of Transformers	% of Total
> 15 and ≤ 30 kVA	20	1%
> 30 and ≤ 100 kVA	526	39%
> 100 and ≤ 500 kVA	700	52%
> 500 kVA	97	7%
Total	**1343**	**100%**

Table 7.10: Ground-mounted distribution transformers – quantities

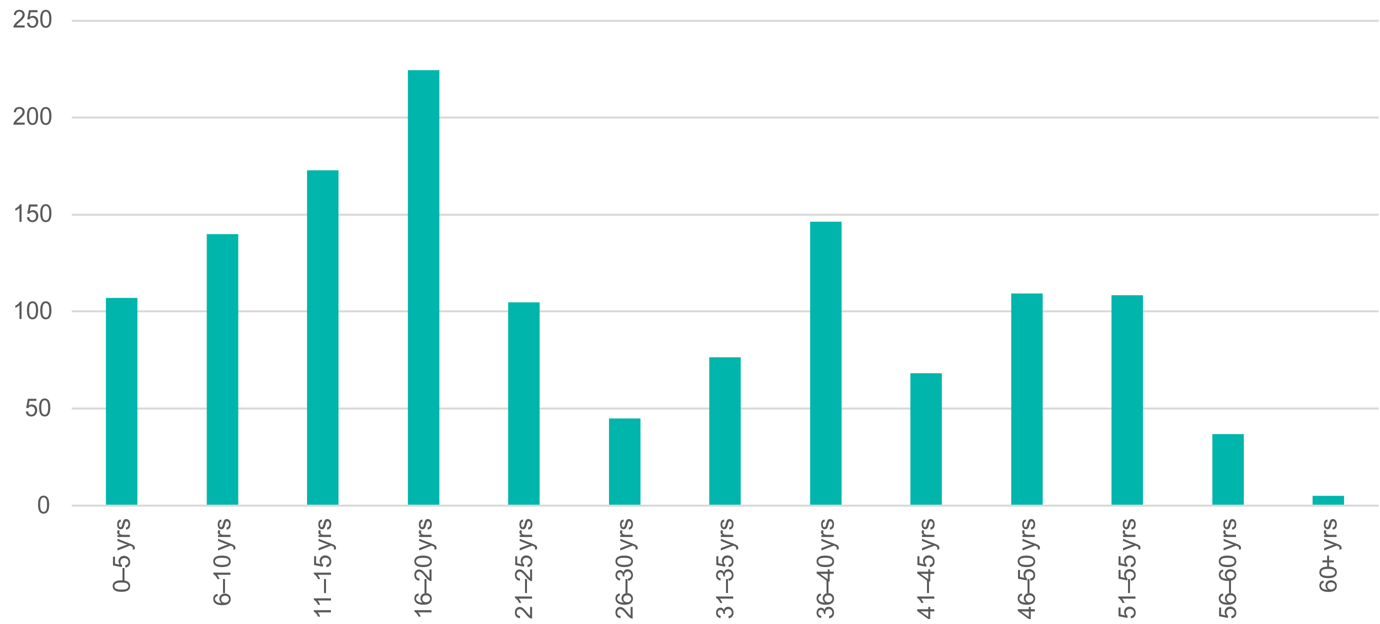


Figure 7.11: Ground-mounted distribution transformers – age profiles

7.4.3.1 Maintenance

Ground-mounted distribution transformers are inspected on both an annual and a five-yearly cycle (see Table 7.11).

Type	Frequency
Ground-mounted transformers	12 monthly – General external condition assessment and labelling
	5 yearly – Full visual check of all components and testing of the earthing systems

Table 7.11: Ground-mounted transformer inspection and maintenance summary

7.4.3.2 Replacement and Disposal

Ground-mounted transformers are replaced as they meet end-of-life criteria, informed by the inspection programme and reported defects. Scrap units are drained of oil and then sold to approved scrap dealers. Used oil is stockpiled until enough volumes are accumulated, and then it is disposed of using approved used-oil dealers.

7.4.4 Pole-mounted distribution transformers

MainPower operates approximately 7,000 pole-mounted distribution transformers. All units are mineral-oil filled. Their ratings, quantities and age profiles are summarised in Table 7. and Figure 7.13.

Rating	Number of Transformers	% of Total
≤ 15 kVA	2,976	42%
> 15 and ≤ 30 kVA	1,970	28%
> 30 and ≤ 100 kVA	1,874	26%
> 100 kVA	343	5%
Total	**7,163**	**101%**

Table 7.12: Pole-mounted transformer quantities

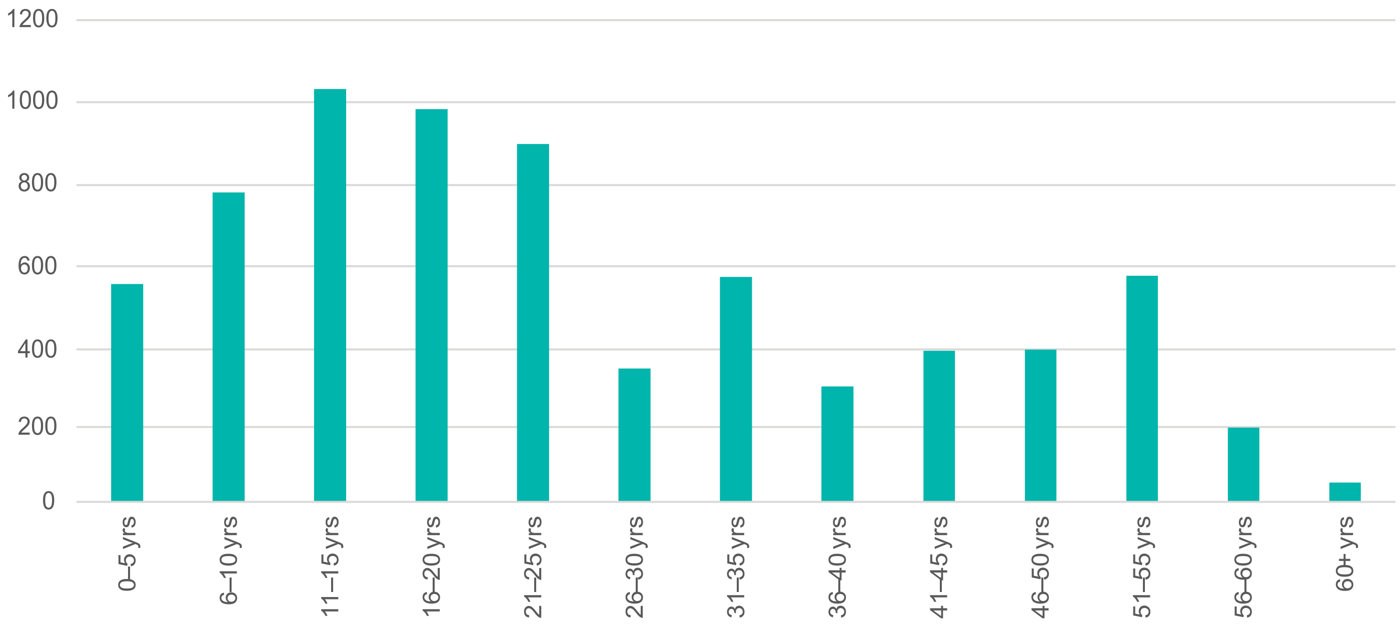


Figure 7.12: Pole-mounted distribution transformer age profiles

7.4.4.1 Maintenance

Pole-mounted distribution transformer inspections are carried out from the ground and include testing of the earthing system (see Table 7.13).

Type	Frequency
Pole-mounted distribution transformers	5 yearly – Full visual check of all components + testing of the earthing systems

Table 7.13: Pole-mounted distribution transformer inspection summary

7.4.4.2 Replacement and Disposal

Pole-mounted transformers are replaced as they meet end-of-life criteria, informed by the inspection programme and reported defects. Scrap units are drained of oil and then sold to approved scrap dealers. Used oil is stockpiled until enough volumes are accumulated, and then it is disposed of using approved used-oil dealers.

7.4.5 Voltage regulators

MainPower operates 24 single-phase 11 kV voltage regulators, which are located across 12 sites, with six new sites commissioned since 2020. Voltage regulators act to stabilise the voltage in the distribution network within prescribed limits for consumers. This asset fleet will remain active, with the possibility of further installations if voltage issues are predicted because of load growth across the network.

The voltage regulators are mostly 220 kVA General Electric devices with automatic controllers. The age profile is between 1 and 20 years, with an expected life of 45 years in normal service. No issues have been identified with the existing regulator assets.

7.4.5.1 Maintenance

The regulator's maintenance programme is aligned with MainPower's asset inspections and maintenance programme for pole-mounted transformers (see Table 7.14).

Type	Frequency
Regulators	5 yearly – Asset inspection, including oil sampling

Table 7.14: Regulator inspection and maintenance summary

7.4.5.2 Replacement and disposal

No replacements are planned for this asset class. Disposal of these units will be in line with other oil-filled equipment at the end of their life, expected in around 30 years' time.

7.5 Zone substations

MainPower's electricity distribution network is supplied via five GXPs from the Transpower 220 kV and 66 kV transmission circuits passing through the region. There are 17 MainPower zone substations that operate at 66 kV and/or 33 kV to supply the 11 kV and 22 kV distribution network. An image of the electricity distribution network is shown in Figure 7.14, followed by a summary of the zone substation capacity and feeders (Table 7.15).

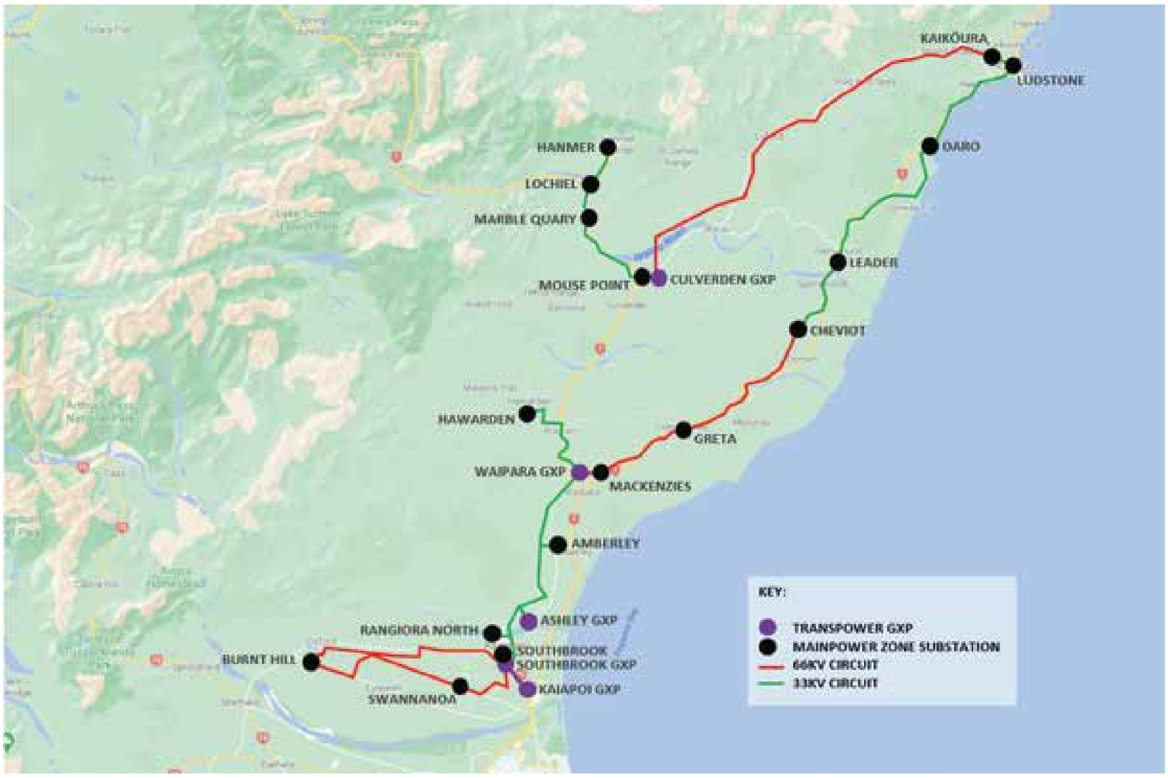


Figure 7.13: Zone substation locations

Site	Voltage (kV)	Substation Capacity (MVA)	Type
Southbrook	66/11	80	Indoor
Swannanoa	66/22	46	Indoor
Burnt Hill	66/22	46	Indoor
Amberley	33/11	8	Indoor
Mackenzies Road	66/11	4	Outdoor
Greta	66/22	4	Outdoor
Cheviot	66/11	4	Outdoor
Leader	33/11	4	Outdoor
Oaro	33/11	0.5	Outdoor
Ludstone Road	33/11	12	Indoor
Hawarden	33/11	4	Outdoor
Mouse Point	33/22	26	Outdoor
Marble Point	33/11	0.2	Outdoor
Lochiel	33/11	0.3	Outdoor
Hanmer	33/11	6	Indoor
Kaikōura	66/33	16	Outdoor

Table 7.15: Zone substation statistics

7.5.1.1 Maintenance

Zone substations are maintained on three overlapping cycles, ranging from regular visual inspections through to a major zone substation service requiring substation shutdown (see Table 7.16).

Type	Frequency
Zone substations	3 monthly – Visual inspection/visual condition assessment
	12 monthly – Thermographic and partial discharge testing
	5 yearly – Major zone substation service with electrical testing on all equipment

Table 7.16: Zone substation inspection and maintenance summary

7.5.1.2 Replacement and disposal

Replacement of zone substations is typically driven by network growth and managed as a major capital expenditure project. Where possible, timing is optimised to coordinate replacement of end-of-life assets with additional sub-transmission development drivers, which include engineering, economic and security-of-supply analysis and optimisation.

7.5.2 Switching substations

In addition to zone substations, MainPower operates seven switching stations that form part of the 11 kV electricity distribution network (see Table 7.17). These are strategic switching points that supply various feeder circuits throughout a localised area.

Site	Voltage	Type
Pegasus	11 kV	Indoor
Kaiapoi North	11 kV	Indoor
Rangiora West	11 kV	Indoor
Percival St	11 kV	Indoor
Bennetts	11 kV	Indoor
Kaiapoi S1	11 kV	Indoor

Table 7.17: 11 kV switching stations

7.5.2.1 Maintenance

Switching substations are maintained on the same cycles as the zone substations mentioned above.

7.5.2.2 Replacement and disposal

Switching station assets that reach their maximum practical life as assessed by AHIs are considered for replacement with modern, compact, ground-mounted kiosks.

7.6 Underground assets

The underground assets portfolio is made up of four asset fleets, shown in Table 7.18.

Asset Fleet	Length/Quantity
High-voltage underground cables	378 km
Low-voltage underground cables	1,272 km (including streetlight circuits)
Low-voltage service boxes	Approx. 13,800
Low-voltage link boxes	711

Table 7.18: Underground asset quantities

7.6.1 High-voltage underground cables

MainPower's high-voltage underground cables are primarily either 95 mm^2 or 185 mm^2 aluminium conductor, although more recently, 300 mm^2 aluminium conductor cables are being used for major urban feeders or to supply distribution switching stations. Smaller sizes, typically 35 mm^2 aluminium conductor, are used for rural consumer spurs.

Most of our conductor assets are within their nominal technical life. Known defects with this asset class are generally related to the cable terminations or joints. In particular, historical "pothead"-type terminations are replaced proactively because of known age-related failures.

7.6.1.1 Maintenance/Inspections

The inspection criteria for these assets fall within the maintenance and inspection programmes for other asset types – typically assets housing and supporting the cable termination, such as distribution buildings, distribution kiosks, overhead lines and zone substations. All end terminations are inspected by either thermographic or acoustic inspection, no less than five yearly, as part of these inspection programmes.

The only exception is sub-transmission cables, which operate at higher than 22 kV; these cables have specific electrical tests conducted on a five-yearly basis to monitor and trend their condition. This is due to the higher impact of failure with these assets.

We are actively engaged in supporting and educating the local community and contractors about the risks of excavating near underground cable assets. We are a member of the “beforeUdig” online service and provide cable-locate and stand-over services to local contractors or individuals.

7.6.1.2 Replacement and disposal

MainPower does not currently have a scheduled replacement programme for underground high-voltage cables. Replacement for cables is typically the result of inspection data or faults. A small section of 33 kV cable has been identified for replacement within the 10-year period, due to its condition.

7.6.2 Low-voltage underground cables

MainPower’s low-voltage underground cables are primarily 185 mm^2 aluminium cables, with some 120 mm^2 aluminium cables historically installed in smaller subdivisions, owing to their lower load requirements.

7.6.2.1 Maintenance/Inspections

The inspection criteria for these assets fall within the maintenance and inspection programmes for other assets, which typically are assets housing and supporting the cable termination, such as distribution buildings, kiosks and boxes, overhead low-voltage lines and zone substations. Most end terminations are inspected visually at five-year intervals, with a criticality-based approach employed to cable termination locations in higher-criticality areas such as business districts, parks, public amenity areas and schools (see Table 7.19).

Type	Frequency
Low-voltage underground cables	5 yearly – As part of general inspection and maintenance programme

Table 7.19: Low-voltage underground cable inspection summary

7.6.2.2 Replacement and disposal

MainPower does not currently have a scheduled replacement programme for underground low-voltage cables. Replacement for cables is typically the result of inspection data or faults.

7.6.3 Low-voltage distribution boxes

MainPower's low-voltage distribution boxes consist of:

- **Service boxes:** These are small plastic boxes manufactured by either Gyro Plastics or TransNet, typically housing up to 12 standard domestic service fuses, which are used for single- or three-phase consumer connections. Some larger boxes, the same make as link boxes, are used for commercial connections where physically larger fuses are required. Some historical service box types that are constructed of metal frames with fibreglass lids exist on the network.

- **Link boxes:** These are larger than service boxes, made of thermoplastic, and typically house 4 to 10 vertically mounted service fuses for either domestic or commercial consumer connections. Link boxes provide an alternative supply point between distribution transformers and allow reconfiguration of the network. Some historical steel boxes exist on the network.

Low-voltage distribution boxes incorporate safety features into box design. Access is restricted and controlled via our Network Operations and Control Centre (NOCC).

MainPower recently completed a condition assessment programme to document the condition of all link and service boxes. This programme was completed in 2023, with condition data captured electronically over the five-year maintenance cycle.

7.6.3.1 Maintenance

Criticality-based maintenance is employed to determine the inspection priority of the low-voltage distribution boxes (see Table 7.20). For those located in higher-criticality areas, such as business districts, parks, public amenity areas and schools, these receive a more frequent inspection programme.

Type	Frequency
Low-voltage distribution boxes	5 yearly – Inspection of box and contained equipment

Table 7.20: Low-voltage distribution box inspection summary

7.6.3.2 Replacement and disposal

MainPower currently has a programme to replace historical metal frame service boxes over the next 10 years, driven by asset condition. Other low-voltage distribution box replacements are primarily driven by defects identified by the inspection programme, or as a result of third-party damage.

7.7 Vegetation management

The majority of MainPower's overhead network traverses rural areas. Vegetation is an ongoing concern and a common cause of outages, especially during high-wind events. MainPower communicates regularly with the public through different channels, including local newspapers and radio. MainPower's aim is to educate tree owners and the public about their responsibility for maintaining trees and the risks of trees falling on power lines.

MainPower has a dedicated team for managing vegetation, including a skilled team of arborists who undertake inspections and trimming around MainPower's network.

7.7.1 Maintenance

MainPower's Vegetation Programme is evolving and moving towards the digital future. Utilising the LiDAR project, we were able to identify vegetation encroachments in the short term, which were all proactively cut and removed from the network.

MainPower will continue to scope the greater part of the network biennially, while prioritising our high fire risk areas by visiting them on an annual basis. This approach will allow us to continue clearing vegetation proactively, enabling us to conjointly explore other forward-looking methods of Vegetation Programme delivery. Investigative steps have begun into combining LiDAR and other risk-based vegetation technologies to promote efficiencies in trimming schedules, comprehensive overviews, and improved network safety.

This will eventually lead to better vegetation management plans to maintain corridors and clearances in the future.
The creation of the network Digital Twin as part of the LiDAR project initiated this year helped MainPower identify vegetation encroachments in the short term, which have all been proactively cut and removed from the network. This will eventually lead to better vegetation management plans to maintain corridors and clearances in the future.

MainPower has two full-time arborist crews who carry out most of the vegetation maintenance within our region and provide supervision to third-party contractors working in the vicinity of our lines. These crews are supported by a Vegetation Inspector and Vegetation Control Supervisor, who work as required with tree owners and local authorities to support the maintenance programme.

7.8 Secondary systems

Secondary systems provide protection and operational control to the electricity distribution network's primary assets. This section covers the following types of secondary systems:

- DC systems
- Protection
- Communication/SCADA
- Load control/ripple plant.

The secondary system assets help MainPower deliver its reliability and safety-service levels. They are a vital asset fleet for ensuring the protection of the electricity distribution network assets, personnel and the general public. The systems are required to operate during loss of electricity supply to their respective sites and enable restoration.

7.8.1 DC Systems

MainPower's DC systems are split into two main parts:

- Batteries
- Battery chargers.

A range of different battery models, by different manufacturers, are spread across the network, typically installed in zone and switching substations, pole-mounted recloser sites, and communication and repeater sites (see Table 7.21).

Asset	Nominal Life	Quantity
DC batteries	10 years	246
	5 years	270
	2 years	3
	Total	**519**

Table 7.21: DC battery quantities based on nominal life

MainPower has standardised with one battery supplier to provide efficiencies in procurement, installation and operation. Some known defects across the existing battery fleet include a shorter-than-expected asset life and historical issues caused by installing incorrect battery types for the intended purpose.

DC chargers include rectifiers, DC–DC converters, controllers and other associated hardware. MainPower has a range of types, from older in-house-built types through to modern SCADA-connected units. As with battery replacement, one local supplier has been chosen for all new chargers.

7.8.1.1 Maintenance

Batteries and DC chargers are frequently inspected and tested because of their importance for monitoring and controlling the network under contingency events (see Table 7.22).

Location	Frequency
Substation	3 monthly – Visual inspection + self-test (if available with charger model) 12 monthly – Electrical tests
Recloser	12 monthly – Visual inspection + electrical test
Communication site	6 monthly – Visual inspection + electrical test
All sites	Real time – Battery/charger diagnostics (if connected via SCADA)

Table 7.22: DC battery and charger inspection and maintenance summary

7.8.1.2 Replacement

Scheduled replacement of batteries is prioritised based on a combination of age relative to expended design life and inspection data. Batteries that prematurely fail are replaced immediately. DC charger replacement is primarily driven by end of life, obsolescence or lack of SCADA functionality.

7.8.2 Protection

The electricity distribution network has protection relays located in zone and switching substations, RMUs and reclosers. Figure 7.15 shows the number and age of the current protection relays.

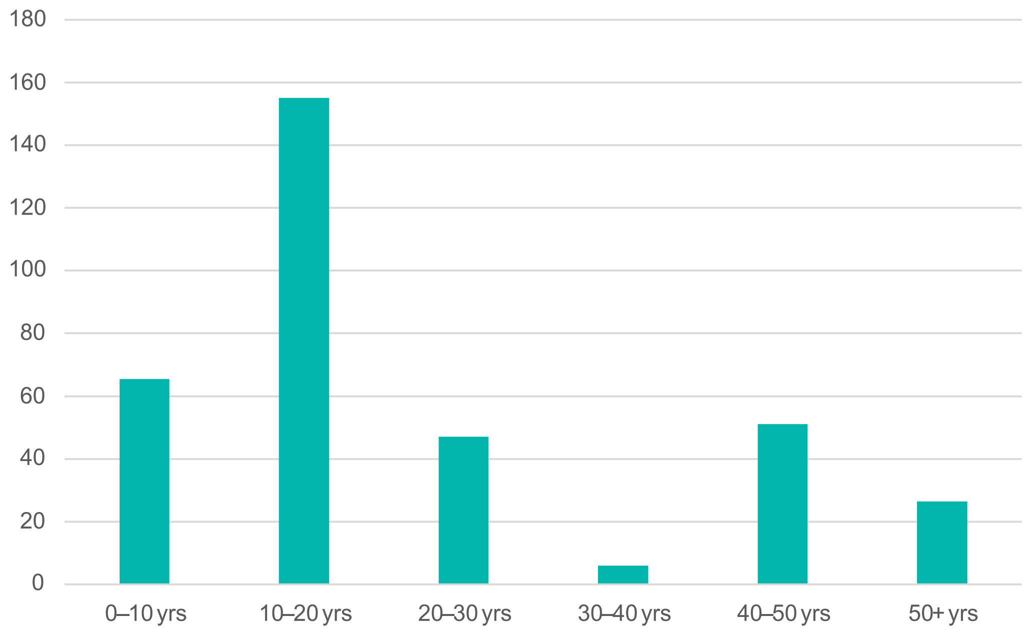


Figure 7.14: Protection relay age profile

7.8.2.1 Maintenance

Regular maintenance of the protection relays is critical in verifying operations and providing protection of the electricity distribution network primary assets (see Table 7.23).

Location	Frequency
Zone/switching substation	• 3 monthly – Visual inspection • 5 yearly – Full system test
Recloser	• 12 monthly – Visual inspection • 10 yearly – Full system test
RMU	• 12 monthly – Visual inspection • 5 yearly – Full system test
All sites	• Real time – Relay fail and other diagnostics (where available with digital relays)

Table 7.23: Protection relay inspection and maintenance summary

7.8.2.2 Replacement

Where possible, scheduled replacement of protection relays is combined with the replacement of the associated switchgear. MainPower also has a replacement programme to progressively replace older electromechanical relays with modern digital relays, providing additional protection functionality and control.

7.8.3 Communications and SCADA

MainPower operates both a voice and data communications network via a combination of digital and analogue radio and fibre. The communications network is characterised by radial links out of the MainPower head office, located in Rangiora, to cover the densest part of the electricity distribution network in the Waimakariri region. A long-reach radio link extends up the east coast to service the Kaikōura region. Fibre links are limited to six sites within the Rangiora urban area, including MainPower's head office, four substation sites and the Waimakariri District Council offices.

Seven radio repeater sites are used to support the communications network, with three located in zone substations and four in stand-alone repeater sites. A visual representation of the radio communications, which currently use Tait voice radios and Mimomax data radios, is shown in Figure 7.16.

Figure 7.15: MainPower's voice and data communications network

MainPower's SCADA system is an Open Systems International ADMS. All remote SCADA sites use the DNP3 communication protocol. MainPower is also trialling new field devices with remote communication facilities for improved visibility and control of the network.

The data and voice networks run on Tait EE band equipment for the mobile repeaters and J band for the inter-site linking. MainPower has deployed several narrow-band digital radio systems of both point-to-point and point-to-multipoint. These provide communications for SCADA remote terminal units and remote engineering access at very low bandwidths, using a mixture of Mimomax, Dataradio and Racom RipEX technology. The maximum capacity of the newer systems currently deployed is 360 kbit/s, and they are operating reliably.

7.8.3.1 Maintenance

Communication and SCADA systems are constantly monitored by the MainPower Engineering Team. Equipment at both zone substation and repeater sites are regularly inspected and serviced on the schedule shown in Table 7.24.

Asset Fleet	Frequency
Communications and SCADA	6 monthly – visual inspections
	12 monthly – diagnostic testing and servicing

Table 7.24: Communications and SCADA system inspection and maintenance summary

7.8.3.2 Replacement and disposal

MainPower is planning progressive replacement of the analogue radio systems with a digital radio system at each of the repeater sites. The increase in capacity and functionality of the digital radio systems can support native lone- and remote-worker systems and increase bandwidth for improved digital services at substations.

7.8.4 Load control and ripple plant

MainPower uses Landis+Gyr SFU-K ripple injection plant, using Decabit code for load control and tariff switching. The plants operate at an injection frequency of 283 Hz, and all plants are GPS synchronised. Most load control receiver relays are in consumer smart meters or are Zellweger/Enermet RM3 installed between 1993 and 1997. The remainder are the later Landis+Gyr RC5000 series and, more recently, RO3-type relays (see Table 7.25).

Rating	Age (years)	Operating Voltage (kV)
Kaiapoi GXP	19	11
Ludstone Rd	20	11
Mouse Point	19	33
Southbrook	2	11
Waipara GXP	18	66
Ashley GXP	9	11
Swannanoa	9	22
Burnt Hill	9	22

Table 7.25: Load plant location, age and operating voltage

While the load control plants are generally in good condition, the SFU-G transmitter at Kaiapoi GXP is considered obsolete by Landis+Gyr and is no longer supported. MainPower has a complete spare unit on warm standby in case of failure.

7.8.4.1 Maintenance

Load plant control and specialist equipment maintenance is contracted out to Landis+Gyr under a service agreement. This covers annual inspections and testing, as well as carrying critical spares in their Auckland warehouse. MainPower has a 24-hour response arrangement with Landis+Gyr to attend to any faults that MainPower's technicians cannot repair.

MainPower staff carry out separate inspections and services of the high-voltage equipment on an annual and three-yearly cycle. Defects are reported and managed as per MainPower's defect management processes.

7.8.4.2 Replacement and disposal

The 33 kV load plant at Southbrook was replaced with an 11 kV containerised unit during the zone substation rebuild in 2021, making available an SFU-K transmitter that has been used to replace the obsolete Kaiapoi SFU-G unit. The remaining Southbrook components are being assessed for their suitability as spares for other sites.

7.9 Property

MainPower owns a range of buildings that serve both the electricity distribution network and non-network services. This covers corporate structures and properties, communication repeater sites, zone substation control buildings and distribution substations, which are a mix of buildings and smaller housings for electrical equipment. The types and numbers are shown in Table 7.26.

Building Type	Quantity
Zone substation control building	22
Distribution substation	34
Holiday home	2
Office	4
Repeater site	4
Staff house	2
Storage building	6
Equipment and kiosk cover	910
Total	**962**

Table 7.26: MainPower's property and building assets

7.9.1 Zone substation buildings

There are 22 zone substation control buildings located across MainPower's network area. These buildings range from small portable sheds, housing up to five control panels, through to multiroom permanent constructions that include indoor switchgear and toilet facilities. A breakdown by construction and purpose is shown in Table 7.27.

Construction Type	Control Only	Control + High-Voltage Switchgear
Timber	5	2
Concrete block	4	2
Concrete tilt slab	0	7
Container	0	2
Totals	**9**	**13**

Table 7.27: Zone substation building types

7.9.1.1 Maintenance

Zone substation buildings are inspected on a three-monthly regime as part of the zone substation routine inspection programme, as shown in Table 7.28.

Asset Fleet	Frequency
Zone substation buildings	3 monthly – Visual inspection

Table 7.28: Zone substation building inspection summary

All zone substation buildings had a detailed seismic assessment and building code compliance assessment carried out during the 2019 financial year. The outcomes of this assessment are being used to inform whether future strengthening work is required.

Asbestos surveys have been carried out on all zone substation buildings. Warning notices have been fitted where asbestos has been found (or assumed to be present) in the building materials or equipment in the buildings.

7.9.1.2 Replacement and disposal

As the structural assessments of the substation buildings did not indicate any serious faults with the buildings, no building replacements are planned in this 10-year planning period.

7.9.2 Distribution substation buildings

MainPower has 33 distribution substations that are housed in stand-alone buildings. These were generally built during the Municipal Electricity Department era and are of solid concrete or masonry construction. They typically contain high-voltage switches or circuit breakers, an 11 kV/400 V transformer and a low-voltage distribution panel. Their ages range from 20 to 62 years, with most in the range of 50 to 60 years, as shown in Figure 7.17.

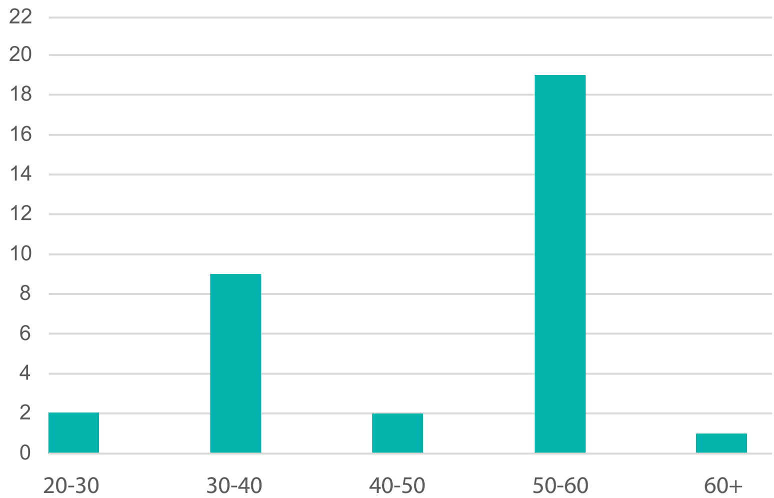


Figure 7.16: Age profile of distribution substation buildings

These buildings are in generally good condition, given their age. A detailed structural assessment in 2019 indicated they are fit for purpose, with some modifications required on a selection of buildings to increase their strength, typically in the roofing.

7.9.2.1 Maintenance

The solid concrete or masonry construction of these buildings requires little ongoing maintenance. Repairs and maintenance are carried out when issues are raised during routine inspections or in field defect reports.

7.9.2.2 Replacement and disposal

As the structural assessments of the substation buildings did not indicate any serious faults with the buildings, no building replacements are planned in this 10-year planning period.

7.9.3 Distribution kiosks

Distribution kiosks are small ground-mounted covers that house electrical equipment. The covers are constructed from various materials, typically steel, fibreglass or plastic. Figure 7.18 shows the number and age of the distribution kiosks.

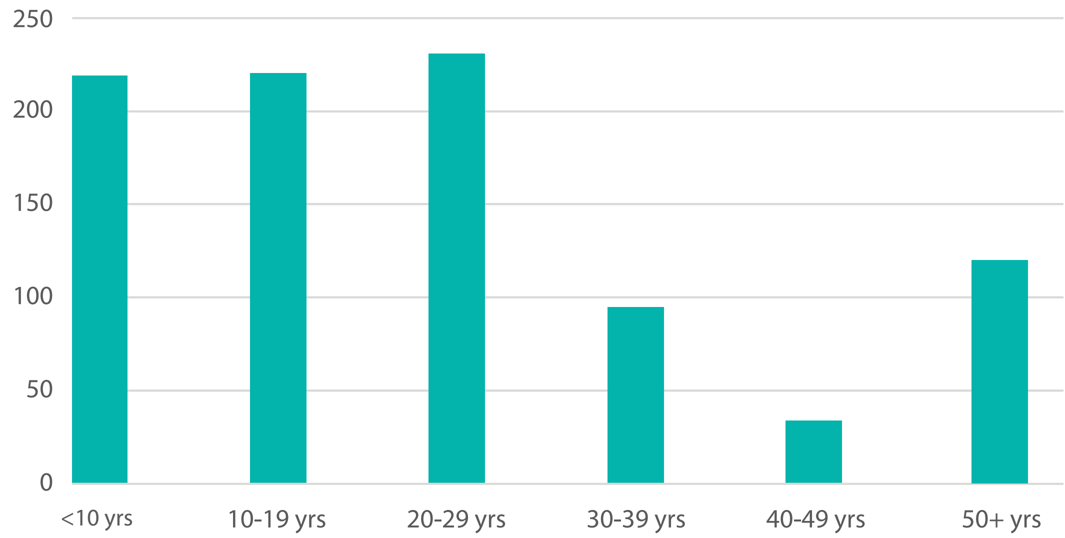


Figure 7.17: Age profile of kiosk covers (enclosures)

While the covers are generally in good condition, known issues include steel covers being prone to corrosion, especially in coastal areas, and fibreglass covers being susceptible to UV damage over time. These defects are monitored during the kiosk inspection programme, and repairs or replacements are made where necessary.

7.9.3.1 Maintenance

Kiosk covers are visually inspected on an annual basis as part of the electrical equipment inspections at the site.

7.9.3.2 Replacement and disposal

MainPower does not currently have a scheduled replacement programme for distribution kiosk enclosures. Defective enclosures identified during inspections are repaired where possible or replacement is coordinated with other works.

7.9.4 Non-electricity distribution network buildings

MainPower owns offices, administration buildings, operational buildings, and staff and holiday housing throughout the North Canterbury region (see Table 7.29).

Description	Location	Age (Years)
Staff Housing – #1	Culverden	5
Staff Housing – #2	Culverden	4
Office building	Culverden	43
Storage shed/workshop	Culverden	43
Holiday home	Hanmer Springs	43
Holiday home	Kaikōura	43
Corporate office and operational facilities	Rangiora	10

Table 7.29: MainPower's non-electricity distribution network buildings

MainPower's head office in Rangiora serves as the main location for corporate and operational management of the business and electricity distribution network.

The buildings consist of:

- a two-storey 2,100 m^2 office building constructed to an Importance Level 4 standard.
- a single-storey 320 m^2 café constructed to an Importance Level 3 standard.
- a 2,000 m^2 single-storey store, garage and workshop building, with 660 m^2 of mezzanine storage area, constructed to an Importance Level 3 standard.

MainPower's electricity distribution NOCC and server room are both located in the head office building, with the ability to work remotely if required to ensure ongoing operational capability during a major event. MainPower also provides the site as a backup Emergency Response Centre for local authorities in the event those authorities' main facilities are not occupiable.

A peak ground acceleration monitor installed at the site supplies real-time data following earthquake events. The data is received within 90 seconds of an earthquake and the ground acceleration monitor compares the site acceleration against building service levels, informing key staff of any possible damage to the building or its services.

7.9.4.1 Maintenance

Much of the facilities and equipment across MainPower's non-network property requires regular maintenance to ensure operational functionality. Ongoing contracts are managed with around 30 service providers to ensure the sites are maintained.

7.9.4.2 Renewal

We have a projected renewal programme out to FY50, with major replacement scheduled for FY25 and FY28, mainly consisting of renewing internal finishes such as carpet and paint, and external finishes such as wall cladding.

7.10 Innovations

MainPower continues to innovate. In 2023, we completed our Digital Twin programme for the lifecycle design management of all our overhead structures, including an environment to truly model the impact of climate change on our network assets.

The implementation of CBRM modelling for our overhead and switchgear fleet is progressing well. The first of the CBRM working models to be completed this year will be the poles model, with pole top crossarms and switchgears to follow in the next year.

7.11 Non-electricity distribution network assets

7.11.1 Information technology systems

MainPower's information technology (IT) system consists of multiple software applications hosted internally on physical architecture within a data centre or operated as software as a service (SaaS). Disaster recovery is provided via replication of the internally hosted systems using a data centre in Christchurch.

Integral to the support of this architecture is an integration layer that facilitates the movement of data and synchronisation of master records to ensure integrity between applications.

The key components of MainPower's IT platform are:

- a TechnologyOne ERP-integrated platform that is used for all asset management, works management and financial reporting
- GE Digital's Smallworld GIS, which is used as the primary geographical data repository for electricity distribution asset data
- CRM from Salesforce for managing ICP data, including registry obligations, billing history, and shareholder information on behalf of the Trust
- Open Systems International ADMS for controlling and operating MainPower's network.

7.11.1.1 Enterprise resource process upgrade

The TechnologyOne platform will be migrated to a SaaS, with improvements to the ERP product's usability and the available functionality. The transition to SaaS over the next few years will provide access to new functionality, which will enable improvements to our asset management and operational practices.

7.11.1.2 Technology integration

The Dell Boomi Integration platform has been implemented to replace the existing bespoke integrations, enabling rapid deployment of new integrations and proactive operational monitoring of the integration environment.

7.11.1.3 Data warehouse and decision support expansion

Further investment in data warehouse and analytics technology is planned to improve strategic and operational decision making, with a focus on opportunity identification and improved service delivery.

7.11.1.4 Integrated management system and current state management

MainPower has implemented the Promapp and State3 technologies to create and maintain visibility of the organisation's current state from process, people, technology and consumer experience perspectives.

7.11.1.5 Document management

A core component of our operational capability is controlling and accurately versioning documents and ensuring that the organisation can easily access these documents. The current document management system no longer meets the requirements of the business, and a new project aims to implement an integrated, modern and secure document management solution.

7.11.2 Assets owned at Transpower grid exit points

MainPower owns metering and communications equipment at Transpower GXPs that connect to our network to monitor load for load management and for revenue metering. All have Ion-type meters, installed after year 2000. MainPower's ripple injection plants are located in Transpower GXPs at Waipara, Ashley and Kaiapoi. We also have SCADA and local service equipment associated with load control at these sites.

7.11.3 Mobile generation assets

MainPower has invested in a mobile diesel generation plant to assist with reducing the number of planned interruptions. The plant is rated at 275 kVA. The generator has been fitted on a tandem-axle truck along with the transformer, protection systems and connecting leads. The generator is used during planned work to maintain the supply to customers. It has enough capacity to supply the average load of an urban transformer kiosk, or it can be connected to overhead lines at 11 kV or 22 kV, supplying up to 100 customers. We also have a 500 kVA generator for use with low-voltage customers. This is often large enough to supply small subdivisions during maintenance.

7.11.4 Other generation

MainPower owns and operates a 1 MW generation asset that is located at Cleardale and is connected to the distribution network owned and operated by Electricity Ashburton. The Cleardale site is operated, managed and maintained in alignment with the MainPower network. This generation asset is identified as non-network and does not form part of MainPower regulatory reporting.

8. FINANCIAL EXPENDITURE

This section provides a summary of our expenditure forecasts during the 10-year AMP planning period. It is structured to align with the internal expenditure categories and forecasts provided in earlier sections

8.1 Total Network Expenditure Summary

8.1.1 Total Network Expenditure Forecast

The following Table 8.1 and Figure 8.1 provides the forecast expenditure by category for the 10-year planning period.

Category	Expenditure ($000)									
	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Major Projects	12,462	13,768	13,248	7,200	5,190	9,810	5,135	3,250	3,250	1,500
Network Reinforcements	3,233	3,241	2,768	2,624	2,662	2,382	1,210	1,979	3,154	2,967
Replacement	6,587	13,442	13,302	12,450	10,542	10,009	10,079	10,149	10,219	10,289
Maintenance	7,262	8,853	8,002	7,834	8,068	7,790	7,703	7,786	7,411	7,548
Network Operations	1,647	1,650	1,639	1,561	1,564	1,568	1,580	1,577	1,595	1,572
Non-Network	2,511	4,224	2,229	2,229	3,539	2,249	2,259	2,259	3,259	2,259
Customer Initiated Works	7,500	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
TOTAL	**41,202**	**51,178**	**47,188**	**39,898**	**37,565**	**39,808**	**33,966**	**33,000**	**34,888**	**32,135**

Table 8.1: Network total expenditure summary FY25–FY34

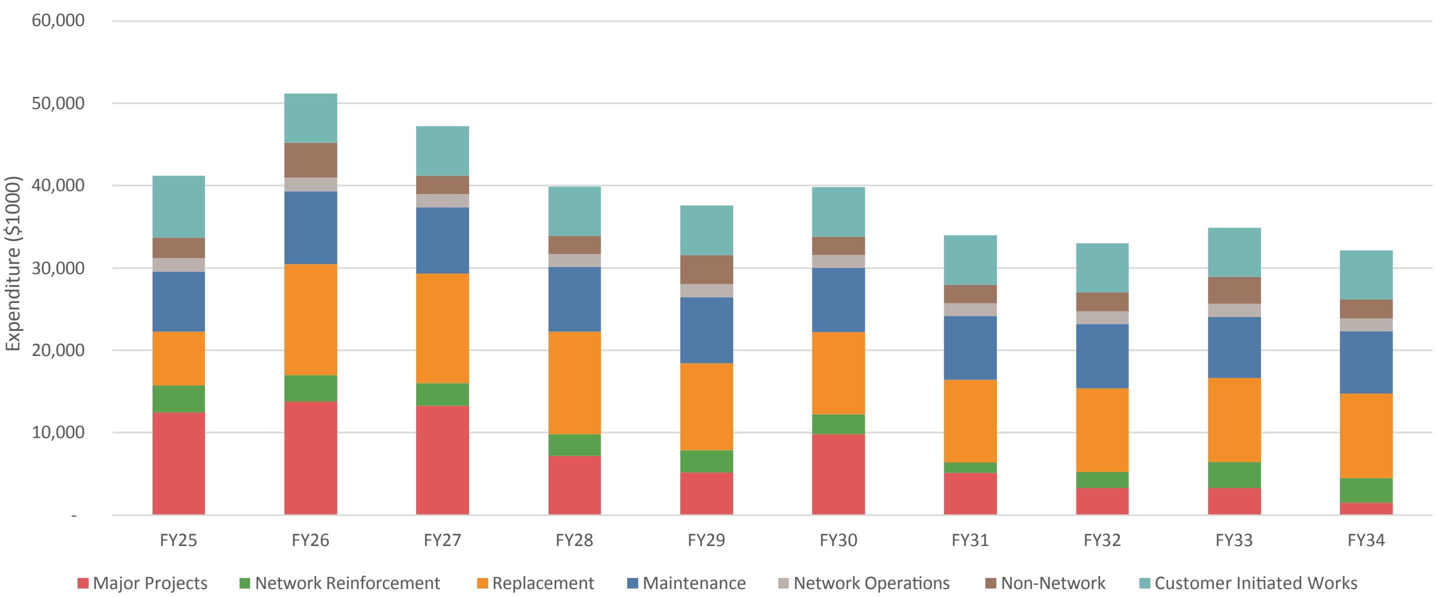


Figure 8.1: Network expenditure forecast FY25–FY34

8.2 Network replacement

8.2.1 Network replacement expenditure

A breakdown of Network replacement expenditure for the 10-year planning period is provided in the Table 8.2.1.

	Expenditure ($000)									
Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Overhead Network	3,500	9,390	9,110	8,838	7,584	7,056	7,126	7,196	7,266	7,336
Zone Substations	80	170	170	80	80	80	80	80	80	80
Distribution Subs & Kiosks	550	818	818	728	548	548	548	548	548	548
Transformers	450	646	546	546	546	546	546	546	546	546
Switchgear	280	500	500	400	400	400	400	400	400	400
Secondary Systems	588	414	414	414	414	414	414	414	414	414
Underground Network	818	1,134	1,374	1,074	600	600	600	600	600	600
Network Property	80	80	80	80	80	80	80	80	80	80
Corrective Replacement	240	290	290	290	290	285	285	285	285	285
Network Replacement Subtotal	**6,587**	**13,442**	**13,302**	**12,450**	**10,542**	**10,009**	**10,079**	**10,149**	**10,219**	**10,289**

Table 8.2: Network Replacement Expenditure Summary

8.3 Network maintenance

8.3.1 Network maintenance expenditure

A breakdown of Network maintenance expenditure for the 10-year planning period is provided in Table 8.3.

	Expenditure ($000)									
Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Overhead Network	2,760	3,260	2,944	2,854	2,749	2,634	2,530	2,430	2,330	2,290
Zone Substations	761	1,139	777	659	879	763	687	824	520	569
Distribution Subs & Kiosks	631	856	742	728	714	700	686	672	658	650
Transformers	464	468	544	526	506	475	408	484	466	454
Switchgear	354	531	433	425	417	409	401	393	385	379
Secondary Systems	63	69	67	65	63	61	59	57	55	53
Underground Networks	449	629	483	464	528	437	519	423	404	471
Network Property	90	103	103	94	94	94	94	94	94	94
Vegetation	1,690	1,800	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590
TOTAL	**7,262**	**8,853**	**8,002**	**7,834**	**8,068**	**7,790**	**7,703**	**7,786**	**7,411**	**7,548**

Table 8.3: Network maintenance expenditure summary

9. CAPACITY TO DELIVER

MainPower's lifecycle asset management process, which is structured on a total lifecycle cost of asset ownership, has as its foundation the activities that occur during the lifetime of the physical asset, as outlined in Figure 9.1.

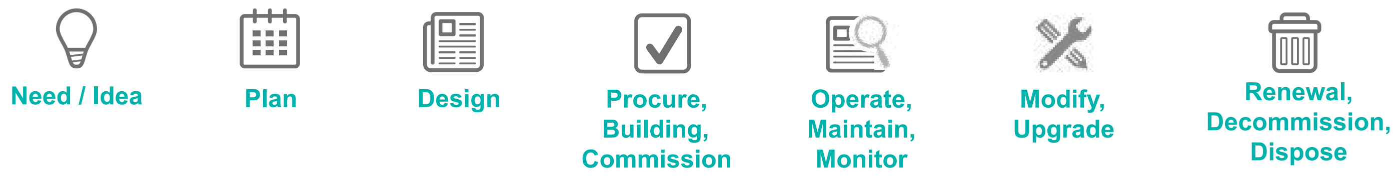


Figure 9.1: Asset lifecycle planning

The roles required throughout the asset lifecycle activities are detailed in Figure 9.2.

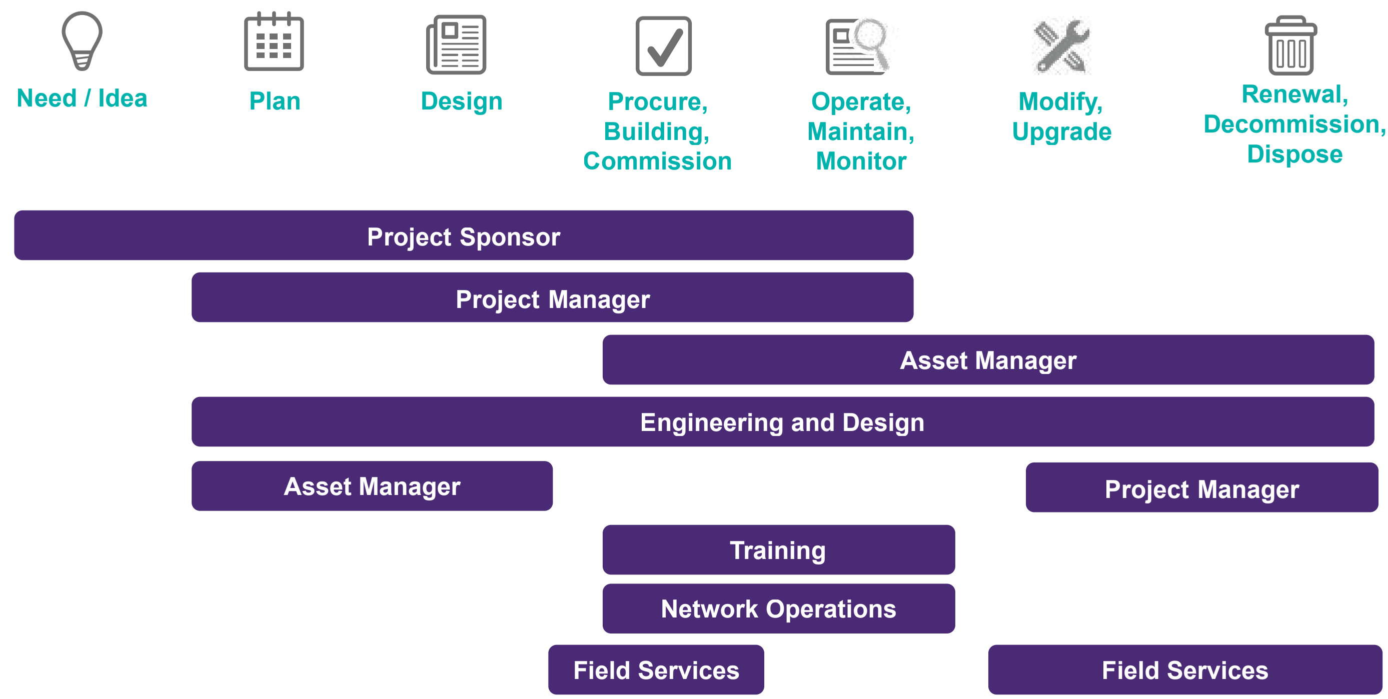


Figure 9.2: Alignment of roles and responsibilities against lifecycle activities

The responsibilities for each of these roles are outlined in clear position descriptions for them.

- **Project Sponsor**: The person with a business need (e.g. renewal of asset, procurement of infrastructure) completes a sponsor's brief and steers the project to completion (i.e. practical completion, including handover).
- **Project Manager:** Delivers the project in accordance with the business project delivery framework or Project Delivery System. The project management resource pool also includes Works Planning and Scheduling Resources.
- **Asset Programme Manager:** Role responsible for delivering all the works associated with all asset renewals within the Asset Management Plan
- **Maintenance Programme Manager: R**ole responsible for delivering of all maintenance activities (Inspection and defect works) for all assets as detailed in the Asset Management Plan.
- **Customer Initiated Works Manager:** Role responsible for delivering all works associated with customer connection requests.
- **Vegetation Programme Manager:** Role responsible for understanding the impacts of vegetation on Network Performance and delivering the works to manage vegetation.
- **Procurement & Property Manager:** Role responsible to ensure cost to delivery all programmes of works are sustainable and aligned with industry best practice.
- **Works Planner:** Role that links with the NOCC and plans network readiness for outages and optimises all works on a per outage basis.
- **Asset Manager:** Ensures all assets are maintained, using the minimum of resources, so they remain fit for purpose and enable the business to achieve its strategic intent. This resource pool also includes the Asset Data, GIS and Records Team.
- **Engineering and Design:** Involved in the development and approval of all designs, including safety by design.
- **NOCC:** MainPower control room resources for the safe operation and network release for working groups.

9.1 Resourcing Requirements

Resourcing is defined for network development, maintenance and renewals, based on typical project resourcing models and rate card information that define labour, materials, plant and outsourcing across all workstreams over the reporting period. Linking asset lifecycle management resources with the 10-year work programme indicates that MainPower's internal resourcing for the management and planning of works is currently adequate. Where there is a deficit, MainPower uses external resourcing to deliver the programme of works.

Asset Management Plan 2024–2034

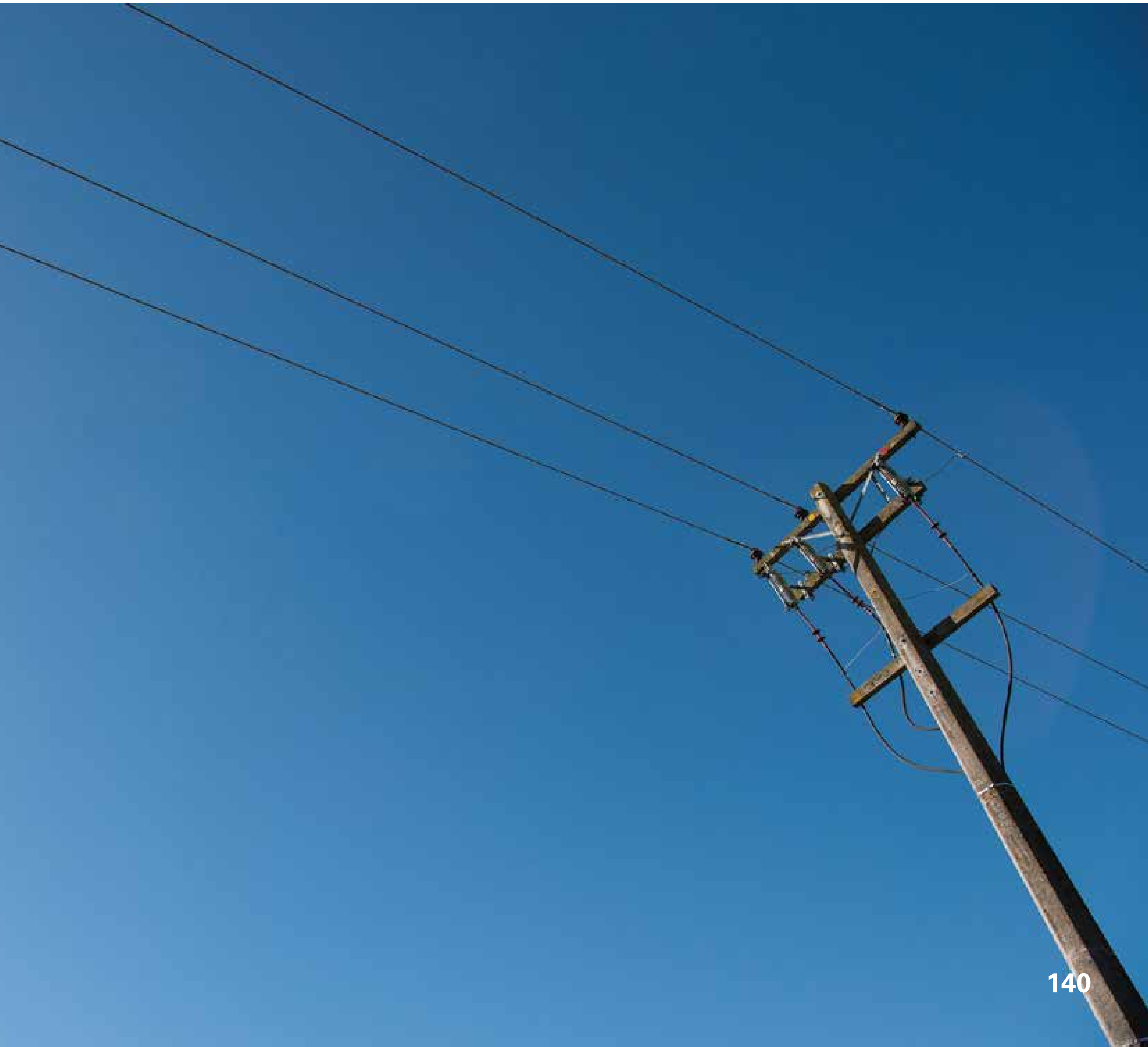
Appendices

This section provides additional information to support MainPower's Asset Management Plan, including our information disclosure schedules.

Appendix 1 – Glossary of terms and abbreviations

Term or Abbreviation	Definition
ADMS	advanced distribution management system
AHI	Asset Health Indicator
AI	artificial intelligence
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
CBRM	condition-based risk management
CDEM	Civil Defence Emergency Management
CIMS	Coordinated Incident Management System
CIS	customer information system
CMMS	computerised maintenance management system
CRM	customer relationship management
DG	distributed generation
Distribution network	The power lines and underground cables that transport electricity from the national grid to homes and businesses
EDB	electricity distribution business
EEA	Electricity Engineers' Association
ERP	enterprise resource planning
EV	electric vehicle
FY	fiscal year
GIS	geographic information system
GWh	gigawatt-hours
GXP	grid exit point – a point at which MainPower's network connects to Transpower's transmission network
HILP	high-impact low-probability
HRC	high rupturing capacity
HV	high voltage
ICP	installation control point
IT	information technology
kV	kilovolt
kVA	kilovolt-ampere
LiDAR	light detection and ranging
LV	low voltage
MEP	metering equipment provider
MVA	mega-volt ampere
MW	megawatt (1 megawatt = 1,000 kilowatts = 1,000,000 watts)
N-1	An indication of power supply security that specifically means that when one circuit fails, another will be available to maintain an uninterrupted power supply
NOCC	Network Operations & Control Centre
OMS	outage management system
RMU	ring main unit
SaaS	software as a service

Term or Abbreviation	Definition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SF6	sulphur hexafluoride
Statement of Corporate Intent	An annual document that outlines the overall intentions of the company and the objectives that the Directors and Trustees have agreed
Sub-transmission	An intermediate voltage used for connections between transmission connection points/bulk supply substations and zone substations – also used to connect between zone substations
Transmission	The high-voltage transmission network that connects areas of generation with towns and cities across New Zealand
Substation	A collection of equipment at one location, including any necessary housing, used to convert or transform electrical energy and connect between two or more feeders
Zone substation	A substation that converts electrical energy from transmission or sub-transmission voltages to distribution voltages



Appendix 2 – Description of asset management systems

System	Definition
Accounting Systems	The TechnologyOne software platform, an enterprise resource planning (ERP) system, is used to integrate financial, works and asset management information. Capital and maintenance expenditure is managed using a comprehensive financial system.
Asset Register	The asset management suite within the TechnologyOne platform is the principal source of data related to MainPower assets.
AutoCAD	Detailed substation plans, standard construction drawings and many subdivision plans are prepared and stored in AutoCAD. Where applicable, these are linked to assets within TechnologyOne. Network details such as cable locations in trenches, boundary offsets and GPS location are stored in AutoCAD to be viewed without complicating the GIS system.
Communication Systems	• Voice radio system for communication to field staff • Digital radio network for communicating with zone substations and other field equipment • Sophisticated telephony system for general land-based and mobile phone communication
Customer Information System (CIS)	This system is used to issue and maintain installation control points (ICPs) with retailers. It also manages customer information, lines tariff and consumption data. Outage information is imported from the outage management system (OMS) and stored against each customer. The CIS is linked to the GIS for customer location information. The CIS is maintained daily from event changes notified by retailers and new connections. The CIS is an important tool for MainPower's revenue protection.
GIS	MainPower uses GE Digital's Smallworld platform (a geographic information system) for the management of spatial asset information. The TechnologyOne software platform has been integrated with the GIS system.
Human Resource Systems	MainPower's human resource information was transferred to the TechnologyOne platform using an iterative, incremental approach during 2016. It includes employment contracts, competency and skill set information, and safety and training records. A succession plan exists within each section.
Infrastructure	MainPower's hardware and server software is continually updated, consistent with modern high-capacity hardware platforms. Information security management includes maintaining off-site backup facilities for stored information for protection from a security breach or disaster.
Inventory Systems	All stock and supply chain details are managed through the TechnologyOne software platform as a single entity. MainPower maintains a separate storage facility for its own stock.
MACK CRM	Customer relationship management system to manage customer enquiries and jobs. Includes registry integration.
Outage Management System (OMS)	Traces across the GIS to identify all affected customers and switching points. For unplanned outages, all relevant fault information is entered into the GIS after the event. Reports are run from the GIS to generate outage statistics as required.
SCADA and Load Management Systems	The Invensys Wonderware "Intouch" SCADA system: • displays voltage, current and status information in real time from remote points on the network • receives instantaneous information on faults • remotely operates equipment from the control centre. We operate Landis+Gyr ripple injection plants and On Demand load management software to control: • customer water heaters, to limit system peak loads and area loading constraints (mainly during winter months) • street lighting • electricity retailer tariffs.
Works Management System	The works management system issues and tracks jobs through the TechnologyOne software platform. It also maintains cost and quality information. A comprehensive job-reporting system provides managers with detailed information about progress of the work plan, work hours and cost against budget.

Appendix 3 – Directors' Certificate

MainPower New Zealand Limited
172 Fernside Road, RD 1, Kaiapoi 7691
PO Box 346, Rangiora 7440
T. +64 3 311 8300 F. +64 3 311 8301

CERTIFICATE FOR YEAR-BEGINNING 1 APRIL 2024 DISCLOSURE

Pursuant to Clause 2.9.1 of Section 2.9 of the Electricity Distribution Disclosure Determination 2012 (consolidated 6 July 2023)

We, ANTHONY CHARLES KING and STEPHEN PAUL LEWIS, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of MainPower New Zealand Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with MainPower New Zealand Limited's corporate vision and strategy and are documented in retained records.

Anthony Charles King	Stephen Paul Lewis
Tony King 02/29/2024 15:49 NZDT	Stephen Lewis 02/28/2024 13:36 NZDT
Date	Date

www.mainpower.co.nz

Appendix 4 – Schedule 11a: Report on forecast capital expenditure

		FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
	11a(i): Expenditure on Assets Forecast	**$000 (in nominal dollars)**										
	Consumer connection	6,404	7,875	6,540	6,720	6,840	6,960	7,140	7,260	7,440	7,560	7,740
	System growth	7,978	15,823	18,049	16,125	8,208	6,020	11,674	6,806	4,030	4,527	4,625
	Asset replacement and renewal	9,145	6,916	14,652	14,898	14,193	12,228	11,910	12,195	12,585	12,876	13,273
	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
	Reliability, safety and environment:											
	Quality of supply	1,696	-	-	756	2,199	1,964	2,131	448	1,497	2,724	686
	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment	1,666	656	491	1,057	792	1,124	703	424	957	818	452
	Total reliability, safety and environment	3,362	656	491	1,813	2,991	3,088	2,835	871	2,454	3,542	1,138
	Expenditure on network assets	26,888	31,270	39,731	39,556	32,232	28,297	33,559	27,133	26,508	28,505	26,775
	Expenditure on non-network assets	694	614	1,978	-	-	1,508	-	-	-	1,260	-
	Expenditure on assets	27,582	31,885	41,710	39,556	32,232	29,805	33,559	27,133	26,508	29,765	26,775
plus	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
less	Value of capital contributions	3,735	5,250	3,815	3,920	3,990	4,060	4,165	4,235	4,340	4,410	4,515
plus	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
	Capital expenditure forecast	23,846	26,635	37,895	35,636	28,242	25,745	29,394	22,898	22,168	25,355	22,260
	Assets commissioned	18,852	16,912	42,490	36,452	32,050	22,276	28,026	27,391	18,138	30,232	22,260
		$000 (in constant prices)										
	Consumer connection	6,000	7,500	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
	System growth	7,475	15,070	16,559	14,397	7,200	5,190	9,810	5,625	3,250	3,593	3,585
	Asset replacement and renewal	8,568	6,587	13,442	13,302	12,450	10,542	10,009	10,079	10,149	10,219	10,289
	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
	Reliability, safety and environment:											
	Quality of supply	1,589	-	-	675	1,929	1,693	1,791	370	1,207	2,162	532
	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment	1,561	625	450	944	695	969	591	350	772	649	350
	Total reliability, safety and environment	3,150	625	450	1,619	2,624	2,662	2,382	720	1,979	2,811	882
	Expenditure on network assets	25,193	29,781	36,451	35,318	28,274	24,394	28,201	22,424	21,378	22,623	20,756
	Expenditure on non-network assets	650	585	1,815	-	-	1,300	-	-	-	1,000	-
	Expenditure on assets	25,843	30,366	38,266	35,318	28,274	25,694	28,201	22,424	21,378	23,623	20,756
	Subcomponents of expenditure on assets (where known)											
	Energy efficiency & demand side management, reduction of energy losses											
	Overhead to underground conversion											
	Research and development											
	Cybersecurity (Commission only)											

Difference between nominal and constant price forecasts

	$000										
Consumer connection	404	375	540	720	840	960	1,140	1,260	1,440	1,560	1,740
System growth	503	753	1,490	1,728	1,008	830	1,864	1,181	780	934	1,040
Asset replacement and renewal	576	329	1,210	1,596	1,743	1,687	1,902	2,117	2,436	2,657	2,984
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	107	-	-	81	270	271	340	78	290	562	154
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	105	31	41	113	97	155	112	74	185	169	102
Total reliability, safety and environment	212	31	41	194	367	426	453	151	475	731	256
Expenditure on network assets	1,695	1,489	3,281	4,238	3,958	3,903	5,358	4,709	5,131	5,882	6,019
Expenditure on non-network assets	44	29	163	-	-	208	-	-	-	260	-
Expenditure on assets	1,733	1,518	3,444	4,238	3,958	4,111	5,358	4,709	5,131	6,142	6,019

Commentary on options and considerations made in the assessment of forecast expenditure

11a(ii): Consumer Connection

*Consumer types defined by EDB**	*FY24* $000 (in constant prices)	*FY25*	*FY26*	*FY27*	*FY28*	*FY29*
Residential	3,500	4,500	3,500	3,500	3,500	3,500
Irrigation	1,400	1,400	1,400	1,400	1,400	1,400
Large User	500	1,000	500	500	500	500
Streetlights	150	150	150	150	150	150
Other	450	450	450	450	450	450
Consumer connection expenditure	6,000	7,500	6,000	6,000	6,000	6,000
less Capital contributions funding consumer connection	3,500	5,000	3,500	3,500	3,500	3,500
Consumer connection less capital contributions	2,500	2,500	2,500	2,500	2,500	2,500

11a(iii): System Growth

	FY24	FY25	FY26	FY27	FY28	FY29
Subtransmission	3,400	4,762	2,718	748	2,100	1,750
Zone substations	4,075	7,700	11,050	12,500	5,100	3,440
Distribution and LV lines	-	-	2,791	697	-	-
Distribution and LV cables	-	2,608	-	452	-	-
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	7,475	15,070	16,559	14,397	7,200	5,190
less Capital contributions funding system growth	-		!	!	!	!
System growth less capital contributions	7,475	15,070	16,559	14,397	7,200	5,190

11a(iv): Asset Replacement and Renewal

	$000 (in constant prices)					
Subtransmission	-	-	-	-	-	-
Zone substations	-	80	170	170	80	80
Distribution and LV lines	5,185	3,500	9,390	9,110	8,838	7,584
Distribution and LV cables	855	818	1,134	1,374	1,074	600
Distribution substations and transformers	1,338	1,000	1,464	1,364	1,274	1,094
Distribution switchgear	348	280	500	500	400	400
Other network assets	843	908	784	784	784	784

	Asset replacement and renewal expenditure	8,568	6,587	13,442	13,302	12,450	10,542
less	Capital contributions funding asset replacement and renewal	-		!	!	!	!
	Asset replacement and renewal less capital contributions	8,568	6,587	13,442	13,302	12,450	10,542

11a(v): Asset Relocations

	*Project or programme**	**$000 (in constant prices)**					
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	All other project or programmes - asset relocations	-					
	Asset relocations expenditure	-	-	-	-	-	-
less	Capital contributions funding asset relocations	-					
	Asset relocations less capital contributions	-	-	-	-	-	-

11a(vi): Quality of Supply

	*Project or programme**	**$000 (in constant prices)**					
	[Description of material project or programme]	1,589	-	-	675	1,929	1,693
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	All other projects or programmes - quality of supply						
	Quality of supply expenditure	1,589	-	-	675	1,929	1,693
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	1,589	-	-	675	1,929	1,693

11a(vii): Legislative and Regulatory

	*Project or programme**	**$000 (in constant prices)**					
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	[Description of material project or programme]	-	-	-	-	-	-
	All other projects or programmes - legislative and regulatory	-					
	Legislative and regulatory expenditure	-	-	-	-	-	-
less	Capital contributions funding legislative and regulatory	-					
	Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

*Project or programme** — **$000 (in constant prices)**

[Description of material project or programme]	1,561	625	450	944	695	969
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	1,561	625	450	944	695	969
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	1,561	625	450	944	695	969

11a(ix): Non-Network Assets

Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Asset Management & Engineering Systems	150	360	565	-	-	300
IT Systems and Assets	500	225	1,250	-	-	1,000
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
[Description of material project or programme]	-	-	-	-	-	-
All other projects or programmes - routine expenditure	-					
Routine expenditure	650	585	1,815	-	-	1,300
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	650	585	1,815	-	-	1,300

Appendix 5 – Schedule 11b: Report on Forecast Operational Expenditure

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Operational Expenditure Forecast	**$000 (in nominal dollars)**										
Service interruptions and emergencies	1,067	1,260	1,308	1,344	1,368	1,392	1,428	1,452	1,488	1,512	1,548
Vegetation management	1,217	1,775	1,962	2,139	2,303	2,459	2,642	2,807	2,988	3,150	3,341
Routine and corrective maintenance and inspection	5,810	5,851	7,688	6,823	6,627	6,899	6,629	6,513	6,667	6,188	6,396
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	8,094	8,886	10,958	10,306	10,298	10,750	10,698	10,772	11,143	10,850	11,285
System operations and network support	11,388	14,280	15,452	15,831	16,025	16,321	16,760	17,068	17,487	17,793	18,186
Business support	5,262	6,291	6,432	6,441	6,556	6,671	6,844	6,959	7,131	7,246	7,419
Non-network opex	16,649	20,571	21,884	22,272	22,581	22,992	23,604	24,027	24,618	25,039	25,605
Operational expenditure	24,743	29,456	32,842	32,578	32,880	33,742	34,302	34,799	35,761	35,889	36,890
	$000 (in constant prices)										
Service interruptions and emergencies	1,000	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Vegetation management	1,140	1,690	1,800	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590
Routine and corrective maintenance and inspection	5,444	5,572	7,053	6,092	5,814	5,948	5,570	5,383	5,376	4,911	4,958
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	7,584	8,462	10,053	9,202	9,034	9,268	8,990	8,903	8,986	8,611	8,748
System operations and network support	10,670	13,600	14,176	14,135	14,057	14,070	14,084	14,106	14,102	14,121	14,098
Business support	4,930	5,991	5,901	5,751	5,751	5,751	5,751	5,751	5,751	5,751	5,751
Non-network opex	15,600	19,591	20,077	19,886	19,808	19,821	19,835	19,857	19,853	19,872	19,849
Operational expenditure	23,184	28,053	30,131	29,087	28,842	29,088	28,825	28,759	28,840	28,483	28,597
Subcomponents of operational expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
Direct billing*	-	-	-	-	-	-	-	-	-	-	-
Research and Development	-	-	-	-	-	-	-	-	-	-	-
Insurance	860	860	860	860	860	860	860	860	860	860	860
Cybersecurity (Commission only)	-										

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Difference between nominal and real forecasts	**$000**										
Service interruptions and emergencies	67	60	108	144	168	192	228	252	288	312	348
Vegetation management	77	85	162	229	283	339	422	487	578	650	751
Routine and corrective maintenance and inspection	366	279	635	731	814	952	1,058	1,130	1,290	1,277	1,438
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	510	423	905	1,104	1,265	1,483	1,708	1,870	2,157	2,239	2,537
System operations and network support	718	680	1,276	1,696	1,968	2,251	2,676	2,962	3,385	3,671	4,088
Business support	332	300	531	690	805	920	1,093	1,208	1,380	1,495	1,668
Non-network opex	1,049	980	1,807	2,386	2,773	3,171	3,769	4,170	4,765	5,167	5,756
Operational expenditure	1,560	1,403	2,712	3,490	4,038	4,654	5,477	6,039	6,922	7,406	8,293

Commentary on options and considerations made in the assessment of forecast expenditure

Appendix 6 – Schedule 12a: Report on Asset Condition

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							
				H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
All	Overhead Line	Concrete poles / steel structure	No.	0.0%	0.6%	12.2%	5.3%	81.9%		2	0.7%
All	Overhead Line	Wood poles	No.	0.5%	3.1%	27.4%	21.9%	47.1%	0.0%	2	4.6%
All	Overhead Line	Other pole types	No.							N/A	
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	1.2%	9.0%	51.6%	38.2%		2	-
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0.1%	42.5%	4.7%	52.7%		3	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	60.0%	20.0%	20.0%		3	10.0%
HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	61.3%	-	38.7%		2	-
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	3.1%	21.9%	68.8%	6.3%	-		2	9.0%
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	1.2%	41.9%	2.3%	1.2%	53.5%		2	14.0%
HV	Zone substation switchgear	33kV RMU	No.							N/A	
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	33.3%	66.7%	-		2	-
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	27.8%	72.2%	-	-		2	
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	12.5%	75.0%	12.5%	-		2	

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	14.3%	14.3%	42.9%	28.6%		3	14.0%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.1%	2.0%	13.3%	63.7%	19.9%		2	2.0%
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
HV	Distribution Line	SWER conductor	km	-	5.3%	29.0%	61.3%	4.4%		2	-
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.7%	1.9%	6.6%	46.7%	44.1%		2	1.0%
HV	Distribution Cable	Distribution UG PILC	km	-	-	-	85.8%	14.2%		2	-
HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	3.1%	18.8%	68.8%	9.4%		2	4.0%
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	9.5%	90.5%	-	-		2	3.0%
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.2%	1.5%	16.8%	38.6%	43.0%		2	2.0%
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.7%	-	21.9%	31.3%	46.0%		3	5.0%
HV	Distribution Transformer	Pole Mounted Transformer	No.	0.7%	18.4%	36.9%	29.0%	15.0%		2	5.0%
HV	Distribution Transformer	Ground Mounted Transformer	No.	0.5%	19.9%	33.6%	30.1%	15.9%		2	5.0%
HV	Distribution Transformer	Voltage regulators	No.	-	4.2%	25.0%	20.8%	50.0%		3	-
HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	14.8%	37.3%	26.1%	21.8%		2	1.0%
LV	LV Line	LV OH Conductor	km	0.5%	2.6%	55.4%	35.1%	6.3%		2	2.0%
LV	LV Cable	LV UG Cable	km	0.0%	-	12.6%	26.7%	60.6%		2	1.0%
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.1%	0.4%	45.6%	10.5%	43.5%		2	1.0%
LV	Connections	OH/UG consumer service connections	No.	-	0.0%	6.6%	22.3%	49.7%	21.5%	1	1.0%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	22.1%	3.4%	33.3%	40.8%	0.3%		1	25.0%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1.0%	32.5%	26.3%	32.3%	7.8%		2	20.0%
All	Capacitor Banks	Capacitors including controls	No.							N/A	
All	Load Control	Centralised plant	Lot	-	28.6%	28.6%	28.6%	14.3%		2	10.0%
All	Load Control	Relays	No.	-	-	62.6%	26.2%	10.7%	0.5%	1	-
All	Civils	Cable Tunnels	km							N/A	

Appendix 7 – Schedule 12b: Report on Forecast Capacity

12b(i): System Growth - Zone Substations

Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
Southbrook	38	40	N-1	2	95%	40	102%	Transformer	To be resolved through load transfers and by construction of a new zone substation in Coldstream.
Burnt Hill	16	23	N-1 switched	6	70%	23	81%	No constraint within +5 years	
Swannanoa	15	23	N-1 switched	7	65%	23	76%	No constraint within +5 years	
Amberley	6	4	N-1 switched	2	151%	20	41%	Transformer	To be resolved through zone substation rebuild
MacKenzies Rd	2	-	N	2	-	-	-	No constraint within +5 years	
Greta	1	-	N	1	-	-	-	No constraint within +5 years	
Cheviot	3	-	N	2	-	-	-	No constraint within +5 years	
Hawarden	4	-	N	-	-	-	-	No constraint within +5 years	
Ludstone	6	6	N-1 switched	-	97%	7	94%	No constraint within +5 years	Increase in capacity from project to rerate existing transformers using cyclic ratings
Leader	2	-	N		-	-	-	No constraint within +5 years	
Oaro	0	-	N	-	-	-	-	No constraint within +5 years	
Mouse Point	16	13	N	-	120%	13	135%	Transformer	To be resolved through non-network load management/control solutions.
Hanmer	5	-	N-1 switched	-	-	11	55%	Transformer	Zone substation upgrade project to increase capacity
Lochiel	0	-	N	-	-	-	-	No constraint within +5 years	
Marble Quarry	0	-	N	-	-	-	-	No constraint within +5 years	Plan to decommission this site within 5 years.
[Zone Substation_16]					-			[Select one]	
[Zone Substation_17]					-			[Select one]	
[Zone Substation_18]					-			[Select one]	
[Zone Substation_19]					-			[Select one]	
[Zone Substation_20]					-			[Select one]	

Appendix 8 – Schedule 12c: Report on Forecast Network Demand

			Number of connections					
12c(i): Consumer Connections								
	Number of ICPs connected during year by consumer type		*FY24*	*FY25*	*FY26*	*FY27*	*FY28*	*FY29*
		*Consumer types defined by EDB**						
		Residential	770	760	760	760	760	760
		General	30	30	30	30	30	30
		Irrigation	1	12	12	12	12	12
		Council Pumping	2	1	1	1	1	1
		Other						
	Connections total		803	803	803	803	803	803
Distributed generation								
		Number of connections made in year	232	243	254	265	276	287
		Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
12c(ii) System Demand								
Maximum coincident system demand (MW)								
		GXP demand	117	118	119	120	121	122
plus		Distributed generation output at HV and above	6	6	6	6	6	6
	Maximum coincident system demand		123	124	125	126	127	128
less		Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points		123	248	250	252	254	256
Electricity volumes carried (GWh)								
		Electricity supplied from GXPs	645	651	657	663	669	675
less		Electricity exports to GXPs	0	0	0	0	0	0
plus		Electricity supplied from distributed generation	27	29	31	33	35	37
less		Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs		672	680	688	696	704	712
less		Total energy delivered to ICPs	636	645	653	661	670	679
	Losses		35	35	35	34	34	33
	Load factor		62%	63%	63%	63%	63%	63%
	Loss ratio		5.3%	5.1%	5.0%	4.9%	4.8%	4.7%

Appendix 9 – Schedule 12d: Report on Forecast Interruptions and Duration

	FY24	FY25	FY26	FY27	FY28	FY29
SAIDI						
Class B (planned interruptions on the network)	140.0	136.7	132.7	128.8	125.2	121.8
Class C (unplanned interruptions on the network)	132.0	128.3	124.5	120.9	117.5	114.3
SAIFI						
Class B (planned interruptions on the network)	0.52	0.57	0.55	0.53	0.52	0.51
Class C (unplanned interruptions on the network)	1.46	1.45	1.41	1.37	1.33	1.30

Appendix 10 – Schedule 13: Report on Asset Management Maturity

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	MainPower has an Asset Management Policy that is firmly part of MainPower's approach to asset management. Awareness of the policy is supported within the business through training and regular updates to staff on Asset Management.		Widely used asset management practice standards require an organisation to document, authorise and communicate its Asset Management Policy (e.g. as required in s 4.2(i) of Publicly Available Specification (PAS) 55). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	As demonstrated in the Asset Management Policy there is clear line of sight between asset management policies and the Statement of Corporate Intent, with asset management strategies and policies used to align other organisation documents and initiatives.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g. as required by s 4.3.1(b) of PAS 55) and has taken account of stakeholder requirements (as required by s 4.3.1(c) of PAS 55). Generally, this will take into account the same policies, strategies and stakeholder requirements as covered in drafting the Asset Management Policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The main focus of MainPower's approach to asset management is to cover full asset lifecycle including total cost of ownership from Idea to Disposal.		Good asset stewardship is the hallmark of an organisation compliant with widely used asset management standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems (e.g. this requirement is recognised in 4.3.1(d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Asset management plans and/or portfolio strategies exist or are currently being developed for all assets. Work remains to further link asset management plans to policies and demonstrate full end-to-end asset life cycle.		The asset management strategy needs to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimise costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/Documented Information
Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The Asset Management Plan, work programme and key initiatives are presented to staff annually, from Board of Directors through to Field Staff. This is done via a variety of methods, from small steering group discussions, to larger general information sessions. The document is also provided and staff are encouraged to read it.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) that detail the receiver's role in plan delivery. Evidence of communication.
Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	MainPower now has roles specifically designated for delivery of Asset Management Plan actions, with reporting on progress documented monthly.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	Asset management and its importance is reported to all staff on a regular basis through company updates and staff engagement meetings. Delivery of asset management plan works is monitored and reported monthly, covering financial performance as well as work completion.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	Incident management processes are well documented and integrated within business activities. Emergency response is managed through the CIMS framework with staff training provided and with mock incidents to further identify improvements. Work is currently underway on developing network contingency plans as well as documenting asset spares.		Widely used asset management practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities, including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) are triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	MainPower has adopted a Plan– Build–Operate model with key executive leadership team members responsible for ensuring MainPower meets its asset management strategies, objectives, and that the asset management plan is delivered.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives, responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. This question relates to the organisation's assets (e.g. s 4.4.1(b) of PAS 55), making it therefore distinct from the requirement contained in s 4.4.1(a) of PAS 55.	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Currently, resources, systems and reporting are in place that demonstrate MainPower is completing asset management effectively on its core assets. These need to be expanded to include more detail across financial performance vs work completed.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Asset Management and its importance is reported to all staff on a regular basis through general company updates/staff engagement meetings.		Widely used asset management practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (e.g. PAS 55 s 4.4.1(g)).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Asset management activities are well defined. Assurance in the form of work/project monitoring and data collection points are used to detail resulting outcomes. Work remains to audit the outcomes; this requirement is agnostic to outsourcing or insourcing. All work outsourced is still overseen by internal project/programme managers.	The Construction Specifications and the Standard Construction Drawing Set have been examined (which form a key control mechanism).	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used asset management standards (e.g. PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities – including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Training for the completion of asset management activities that deliver the required outcomes is in place for some assets. Some training is also provided on-the-job. Work remains detailing the training requirements, enabling the requirements on the team skills matrix and ensuring that competent people exist informed by the forward work programme.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy. For example, if the asset management strategy considers 5-, 10- and 15-year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements for the completion of asset management activities exist within the Asset Management and Operational plans. Activities are risk assessed and controls developed based on the risk appetite of the business. Work remains in developing a clear link between activities required, competency to complete the work and work authorisation.		Widely used asset management standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees (e.g. PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff, e.g. via organisation wide information system or local records database).
Training, awareness and competence	How does the organisation ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	All asset management activities are risk assessed and controls developed based on the risk appetite of the business. Work remains to be completed developing a clear link between activities required, competency to complete the work and work authorisation – see section on Risk within the AMP.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the Asset Management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Pertinent asset management information is communicated to necessary parties to effectively deliver the asset management plan for most assets and workstreams. Work remains to be completed to extend this further, especially with contracted service providers.		Widely used asset management practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include, for example, the communication of the Asset Management Policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee representative(s) and employee trade union representative(s); contracted service provider management; representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset Management Policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
Asset management system documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Currently, MainPower, through process maps and an asset management system document, describes its approach and asset management framework, including who is responsible and for what part of the process they are responsible.		Widely used asset management practice standards require an organisation maintain up-to-date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated (e.g. s 4.5 of PAS 55 requires the maintenance of up-to-date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	MainPower has committed to improving its asset register and information held in its ERP system. In addition, a new data warehouse has been established linking source data into a business improvement environment to help inform asset management activities. Other asset management information systems are also being reviewed by the organisation so that the organisation can improve its approach to asset management.		Effective asset management requires appropriate information to be available. Widely used asset management standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers.	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	This is achieved via a well defined, mapped and documented as-builting process, which includes data quality assurance.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used asset management practice requirements (e.g. s 4.4.6(a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Information requirements are informed by the Asset Management Plan and financial and operational requirements. MainPower has committed to the TechnologyOne ERP, an asset management system that supports improving its maturity in a strategic approach to asset management.		Widely used asset management standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisation's needs, can be effectively used and can supply information that is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Activity risk assessment for asset management activities have been assessed, documented and controls identified (through process mapping and risk bowties). Work remains to be completed detailing the operational risk of all assets (Plant and Equipment Risk Assessments).		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (e.g. s 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Risk assessments are completed and controls identified that inform competency requirements and controls for works. Controls identified for the completion of works form part of the contractor management framework and network access requirements. The end-to-end process detailing the implementation and monitoring of these controls remains to be completed.		Widely used asset management standards require that the output from risk assessments is considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisation's risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how are the requirements incorporated into the asset management system?	3	Legal statutory risk forms part of the MainPower corporate risk management framework. MainPower also requires staff to complete a ComplyWith survey annually to re-assess compliance against requirements.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (e.g. PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used asset management standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisation's regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Life cycle activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets? This includes design, modification, procurement, construction and commissioning activities.	3	MainPower's asset management, engineering and operational process are well documented in ProMapp. Relevant documents and standards are linked to the ProMapp processes. This includes processes from Asset Creation, Maintenance and Replacement, Engineering and Design, Procurement, Operational activities and as-builting.		Life cycle activities are about the implementation of asset management plan(s), i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (e.g. PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business (e.g. Procurement).	Documented process(es) and procedure(s) that are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, and enhancement, including design, modification, procurement, construction and commissioning.
Life cycle activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Process and procedures are documented that detail how asset management plans are implemented. More work is needed to document and demonstrate that current activities fully align with asset management strategies and are implemented in a cost effective way.		Having documented process(es) that ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g. as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	Overall performance of the system is measured via SAIDI, SAIFI and other performance metrics documented in the regulatory AMP. This covers analysis of poor performing parts of the network and/or assets with specific projects or initiatives to improve performance. Condition assessments are carried out by field staff and office-based experts using data collected from maintenance and inspection programmes.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
Investigation of asset-related failures, incidents and non-conformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances is clear, unambiguous, understood and communicated?	3	Asset failures are investigated depending on criticality, including operational incidents. Roles and responsibilities are defined including the implementation of an organisation-wide incident reporting, management and investigation system.		Widely used asset management standards require that the organisation establishes, implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people, including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances. Documentation of assigned responsibilities and authority to employees. Job descriptions, audit reports. Common communication systems, i.e. all job descriptions on internet etc.

Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	MainPower engaged external support to help review and further develop its asset management system documentation in 2021.		This question seeks to explore what the organisation has done to comply with the standard practice asset management audit requirements (e.g., the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management; for example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
Corrective & preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non-conformance?	3	Incident investigations and corrective actions are undertaken in accordance with MainPower's Incident Reporting and Management operating standard. Asset management work programmes also include both preventative and corrective components, with the objective of preventative programmes resulting in less corrective work. Corrective actions and work are reviewed annually to inform and improve preventative work programmes.		Having investigated asset-related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a business's risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used asset management standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews.
Continual improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset-related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Asset management activities are documented, risk assessed and costed in terms of time, materials, plant and equipment (rate cards). Rate cards are benchmarked against perceived industry standards. All works are pre-costed using the rate card and maintenance activities are assessed against planned and actual costs.		Widely used asset management standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area – looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
Continual improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	By way of industry forums, conferences and technology presentations, and collaboration with other EDBs.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation that does this (e.g. by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Appendix 11 – Schedule 14a: Mandatory explanatory notes on forecast information

Company Name: MainPower New Zealand Ltd

For Year Ended: 31-March-2025

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory – EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. Box 1 explains the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

In preparing the capital expenditure forecasts, MainPower has used the Westpac Economics Forecast Summary sheet November 2023 for the inflation (consumers price index (CPI)) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final four periods of the AMP forecast.

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Index	1.05	1.09	1.12	1.14	1.16	1.19	1.21	1.24	1.26	1.29

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. Box 2 explains the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

In preparing the operational expenditure forecasts MainPower has used the Westpac Economics Forecast Summary sheet November 2023 for the inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final four periods of the AMP forecast.

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Index	1.05	1.09	1.12	1.14	1.16	1.19	1.21	1.24	1.26	1.29