Powering Our Future

ASSET MANAGEMENT PLAN 2023-2033

Network Waitaki

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Introduction

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Introduction

Welcome to our Asset Management Plan (AMP) for the planning period 1st April 2023 to 31st March 2033.

As we provide an essential service to the communities we serve, it is vital that our electricity network meets the evolving needs of our customers and other stakeholders. Our AMP plays a central role in determining the appropriate levels of network planning and investment required to achieve this.

This chapter introduces the AMP and is structured as follows:

Executive summary: Explains our Asset Management approach and summarises the challenges and development ahead for us, including our Capital and Operational Expenditure Forecasts.

Purpose: Explains the purpose and objectives of the AMP; the period and assets covered; the date it was approved by our Board of Directors (the Board); and the intended audience.

Key themes and initiatives: The key themes and initiatives that have been outlined throughout the AMP.

Document structure: An illustration of how the AMP is structured.

1.1 Executive Summary

1.1.1 Our Company

Network Waitaki is a consumer trust owned electricity distribution business (EDB). We have a single shareholder, the Waitaki Power Trust (the Trust), which holds the shares of NWL on behalf of the NWL consumers (our connected customers). The Trust has five elected trustees and appoints directors to the Board to carry out the governance function of the business.

We operate a predominantly overhead rural network supplying the North Otago, Hakataramea, and Ahuriri regions as shown below. We supply the major rural support town of Oamaru as well as several smaller townships.

Figure 1 - Overview of Network Waitaki area of supply

1.1.2 Our Vision

"Powering a vibrant Waitaki"

1.1.3 Our Mission

"Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers"

1.1.4 Alignment with Key Strategic Priorities

In 2022 we revised our 10-year strategic plan that will guide our business to deliver our Vision and Mission. Our strategic priorities are shown below.

Our Strategic Piorities

We excel in what we do, providing a safe, reliable and valuable service for our customers and great place to work for our people

We are effective in our impact on our environment and enabling a sustainable future for the community for which we serve

We provide excellent customer service and community engagement and are valued by the customer, the region and our shareholder

Our strong 'can do' culture underpins our capability to deliver what our customers want

We are a trusted advisor and supplier of innovative energy solutions for our customers, to enable their full participation in the new energy future and a low carbon economy

We have a range of profitable services on offer and are the service provider of choice

We develop the culture, skills and expertise that we leverage to partner with others to create value

We engage and collaborate with key partners to enhance our business and capability, to access expertise and scale, to improve efficiency and service delivery

We will be excellent in our selection, management, and delivery of network and non-network investments aligned to our core competencies

We will enhance our financial performance by making smart investments to deliver shareholder value

This Asset Management Plan looks to detail the key strategic asset management priorities that are aligned to these strategic priorities.

Core Capabiity

This means continuing to focus on the performance on our electricity network in order to provide safe, reliable, cost effective and environmentally sustainable network services to our customers.

We are committed to being a leader in health and safety by ensuring that our network remains safe at all times and we seek to actively manage risks to the public, public property, and our staff. This is a key focus point for asset management decision making, including asset selection, design and construction activities, day to day operation and maintenance of the network, fault and emergency response, and the criteria for removal of assets from operation at or before end of life.

Security and Reliability of supply are of high importance to us and to our customers. Our customer surveys have indicated our customers are generally happy with the reliability they receive for the price that they currently pay. Maintaining and improving this level of security and reliability in a cost-effective manner through the planning period is a focus in our asset management strategies. Our operating environment is changing, and in the context of the increasing number of extreme weather events, we are focussing on ensuring a resilient network and robust response plans to enable the restoration of supply and recovery of our communities following major events. This AMP was largely prepared prior to the devastating Cyclone Gabrielle which hit the North Island in early 2023, and as such our expenditure forecasts do not include any additional allowances for resilience investment as a result of that event. This will be addressed in future AMPs.

We forecast that there will be a high growth of decarbonisation and irrigation demand over the next 10 years along with increasing uptake of emerging technologies such as EVs, solar photovoltaic systems, and battery storage systems nearer the end of this period and increasing rapidly in the decade following. Most of these technologies will be connected to our low voltage networks. Historically, demands on these networks have been predictable and stable over time and our low voltage networks have had very little in the way of monitoring. In order to quantify the impact of these emerging technologies we need to invest in systems that provide us useful data about the performance of our low voltage networks. This will allow us to monitor the both the capacity and quality of supply at the level of our customers and predict and react to developing problems in a timely fashion.

Our network will provide a platform for the decarbonisation of our customers' businesses. Sustainability is an important factor in the ongoing development of Network Waitaki, both from an environmental point of view, and a financial point of view.

Ensuring we have the capacity and capability to deliver the level of service and future options required by our customers is another key focus area, and the development and deliverability of our Asset Management Plan is a major consideration for us. In order to achieve this, we need access to the right skills now and into the future. Obtaining skilled resources is challenging in current times, so our focus is ensuring we can identify future needs to allow us to recruit, train, invest in and grow our team. Our recent recruitment of a People and Culture Manager strengthens our focus in this area and the creation of a comprehensive workforce development plan is an action under way.

Customer Focus

This will be achieved by providing excellent customer service and engagement and will be measured by regular customer engagement and surveying. Our Customer and Community Relations Manager is responsible for developing and managing our customer services and engagement strategy, careers and public safety programmes and internal customer management systems and processes. This will allow us to better understand and meet our customers' needs and priorities.

Enabling Choice

We will investigate the development of a portfolio of innovative solutions for our customers and community to improve service levels, support decarbonisation, and improve the utilisation of our network. These solutions may include demand response and other non-network opportunities to increase network capacity or defer network investment.

Collaboration and Partnerships

We are committed to collaborating and partnering with like-minded companies to help us deliver an affordable customer-focussed network and enable our customers' future technology desires. This allows us to leverage off resources (people, processes and systems) in other businesses to drive efficiency, alignment and standardisation, and to gain access to systems or services where we may not have scale ourselves.

Investment Expertise

We will look to make smart investments, in line with our core competencies to deliver value to our shareholders and customers. This includes our selection and delivery of network investments outlined in the AMP.

1.1.5 Managing our assets

We view effective asset management as a continual cycle, with direction, planning, implementation, and review working together to improve our performance.

Our asset management practice is to actively seek out best practice both from within our industry, and from other industries where it is appropriate. Examples of this are:

- Involvement in industry working groups to do with new technologies
- Attendance at industry conferences and training
- Hosting onsite industry training courses to improve the capability of our engineers and field staff, such as the EEA Safety in Design course.

In FY22 we undertook an independent review of our asset management practices business based on the EEA's AMMAT assessment tool. The outcomes from this assessment are being used as the basis for an improvement plan to ensure that our business is focussed on providing excellence in asset management, in order to provide excellent service and value to our customers, owners and other stakeholders.

A key theme of the company's development over the next few years is developing our Asset Management skills and capability to better align with ISO 55000 principles. In the next few years, key focus areas are:

- Improving the data that we record about our assets, and modernising how it is captured and analysed
- The integration of that data into operational systems to assist us in decision making
- Developing a deeper understanding of the criticality of individual assets to better inform our strategies, and improve the experience of our customers
- Developing, implementing, and improving our digital asset management systems.

Key features of the network are shown in table below.

Table 1 - Key features of NWL network

Parameter	Value
Number of Poles	21,606
Length of 33 kV lines and cables	238 km
Length of 11 kV lines and cables	1,339 km
Length of LV lines and cables	326 km
Number of zone substations	17
Number of connected customers	13,282
Coincident max demand	61 MW
Annual energy delivered to customers	238 GWh

These assets are discussed in detail in **Section 5 Renewals and Maintenance.**

We have traditionally managed our asset life via condition-based renewals and replacements, but we are also working towards utilising better analytical and predictive methods for analysing lifecycle of the assets. This includes the introduction of end-to-end processes that capture information digitally in the field and remove paperwork from the process, the integration of electrical modelling software with our GIS system, and the use of integration software to bring disparate data for analysis.

The key theme of managing the lifecycle of our assets is maintaining safe, reliable operation, while providing good value to our customers.

1.1.6 Developing our Network

We present our Network Development Plan (NDP) in Section 6. Key themes this year are:

We view effective asset management as a continual cycle, with direction, planning, implementation, and review working together to improve our performance.

Our asset management practice is to actively seek out best practice both from within our industry, and from other industries where it is appropriate. Examples of this are:

1.1.6.1 Decarbonisation demand growth

New Zealand must transition away from carbon-based fuels if we are to meet our climate change objectives.

Our country has committed to zero net emissions of all greenhouse gases (except biogenic methane) to zero by 2050. To achieve this, we need to move away from coal, petroleum, and other Carbon-based fuels. It is now clear that electricity will supply a substantial proportion of this energy demand as process heat and our transport fleet move away from fossil fuels, and electricity networks are a key enabler to achieve these objectives.

We expect to see significant growth in electricity demand this decade as customers who currently use coal for process heat convert to electricity. After 2030, we expect growth in EV demand to increase significantly.

Our customers have already committed to 4.5 MVA of decarbonisation projects which we will require supply for by the end of FY24. We expect another large customer to require over 5 MVA by FY27.

We expect EV growth will continue to increase during the planning period and will increase significantly in the 2030s as government policies take effect, supply chains are established, and a secondhand market develops.

We present our planning assumptions around EV and process heat decarbonisation demand growth in **Section 6.4 Our demand scenario assumptions.**

1.1.6.2 Network evolution

Historically we had little need to monitor our low voltage networks as power typically flowed in one direction from our assets to our customer and loads were stable and predictable. The only monitoring we used were maximum demand indicators that we read manually once a year to check that we weren't overloading our transformers.

As our customers take-up more distributed generation, batteries and EVs, we will see two-way power flows and increased loading on our low voltage networks.

In the medium-term we do not expect any issues enabling our customers to connect this new technology, but we need to start understanding the performance of our low voltage networks so we can benchmark existing performance, model future scenarios and develop solutions before we start experiencing network congestion. Visibility of the LV network will allow us to understand whether we are able to influence customer behaviour to reduce impacts on our network. Additionally, the increased visibility of the LV networks provides significant benefits in other areas of our asset lifecycle processes, including safety, reliability, customer service, and asset maintenance and enhancement planning.

We present our plans to evolve our network to enable our customers future technology choices in Section **6.2 Our network evolution roadmap**

1.1.6.3 Regional transmission capacity

Transpower has a capacity constraint on the 110 kV transmission system supplying Oamaru GXP and the lower South Canterbury area. Because this system is "non-core grid", connected parties must fund any investment to alleviate the constraint. If we do nothing, we will be unable to meet our customers' demand.

To enable this increased demand, we plan to:

- Implement a Special Protection System to shed (n) security load if there is a fault on one of the transmission lines supplying Oamaru GXP.
- Temporarily supply new large connections and all new irrigation connections at (n) GXP level security until the constraint on the transmission network is alleviated.

We are on track to implement the Special Protection Scheme before the summer of 2024 and are working through the design phase with Transpower for the new GXP.

We plan to design the new GXP with options to reconfigure it to resupply Oamaru GXP directly via a 110 kV network. This would free up significant capacity into the South Canterbury region and may allow Transpower to feed into their 110 kV transmission system at this point and avoid planned line and transformer upgrades. There will be additional up front costs to provide these options and we will work with Transpower and Alpine Energy to ensure we make the best choices for New Zealand as we finalise our plans.

We present further details in **Section 6.5 GXP Capacity and Security and Section 6.8.1 GXP Projects.**

1.1.7 Our summary of forecast network expenditure

The summary of our forecast expenditure on our network for the planning period is shown in Table 2 below.

Note that these figures do not cover non-network expenditure, or expenditure not associated with the lines business. These estimates are considered to be fairly accurate for the first five years of the planning period, and less accurate beyond that. This is primarily due to many of our investment, maintenance and renewal decisions being very dependent on outcomes of inspections in the first five years, customer growth, the impact of emerging technologies, and other issues that are currently uncertain, including Transpower constraints in North Otago and South Canterbury, central government initiatives, including decarbonisation, growth due to economic factors and asset relocation work that tends to be driven by third party requests.

Table 2 - Summary of forecast network expenditure

Network Capital Expenditure	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Consumer Connection	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509
System Growth	10,829	2,755	4,175	3,800	1,000	3,250	3,650	5,475	7,675	12,590
Asset Replacement & Renewal	5,085	8,818	6,366	6,227	6,146	6,131	5,842	5,911	5,698	5,996
Asset Relocations	-	221	-	-	-	-	-	-	-	-
Reliability, Safety & Environment - Quality of Supply	953	650	450	450	450	500	800	200	200	200
Reliability, Safety & Environment - Legislative & Regulatory	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-
Total Capital Expenditure	**18,376**	**13,953**	**12,500**	**11,986**	**9,105**	**11,390**	**11,801**	**13,095**	**15,082**	**20,295**
Network Operational Expenditure										
Service Interuptions & Emergencies	483	470	460	460	460	460	460	460	460	460
Vegetation Management	712	712	712	712	712	712	712	712	712	712
Routine & Corrective Maintenance and Inspections	1,298	1,379	1,323	1,326	1,312	1,340	1,326	1,326	1,326	1,312
Asset Replacement & Renewal	261	261	243	243	243	201	201	201	201	201
Total Operational Expenditure	**2,753**	**2,821**	**2,738**	**2,741**	**2,727**	**2,713**	**2,699**	**2,699**	**2,699**	**2,685**
Total Expenditure	**21,129**	**16,773**	**15,238**	**14,727**	**11,832**	**14,103**	**14,500**	**15,794**	**17,781**	**22,980**

1.2 Purpose

The purpose of this AMP is to align the management of our assets with our corporate objectives and our mission of "Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers".

This AMP is an integral part of our business planning process alongside other key corporate documents, including our Statement of Corporate Intent, internal strategy plans, annual business plan and budget, Network Development Plan, monthly board reports, and our emergency preparedness documents.

The objectives of this AMP are:

- To link the asset management processes to customer and stakeholder preferences for prices, supply reliability, and the health and safety of our staff and the public.
- To ensure that all asset lifecycle activities, plans, and associated costs are systematically planned with a long-term view towards minimising lifecycle costs, which promotes productive efficiency.
- To ensure the sustainable financial future of the company by understanding the resources required to deliver the required capital and operational workstreams and signalling when those resources will be required.
- To ensure that physical, commercial, and regulatory risks are appropriately managed and understood throughout the life of the asset.

1.3 Scope

The scope of this AMP includes all areas of planning that relate to NWL's regulated electricity distribution services as an Electricity Distribution Business (EDB). This does not include business streams outside the core EDB business, such as electrical and vegetation contracting, metering services, electric vehicle charging, generation, and the fibre optic and private electricity networks.

1.4 Intended audience

The AMP is published on our website (www.networkwaitaki.co.nz), and is aimed at the following readership:

- The Commerce Commission
- Our trustees, directors, and management
- Our staff
- Our customers
- Our other stakeholders
- Interested members of the public
- Other Electricity Distribution Businesses (EDBs)

1.5 Key themes

The key themes for the planning period are:

- The importance of safety on and around the network, both as a healthy and safe workplace for our staff and as a safe utility for the public.
- Improvements in our asset management processes to allow for better delivery of services.
- Meeting our customers' expectations in terms of quality and reliability of supply.
- Identifying and meeting our customers' future energy needs and working closely with them to enable decarbonisation of their energy supply.
- Evolving our network to allow us to accommodate and enable future new technologies that will be delivered to our customers.
- Resilience to natural events identified as a more important issue for our communities.
- Investment in Technology for improved understanding and utilisation of the network.
- Improvements in deliverability of the AMP.

1.6 Document structure

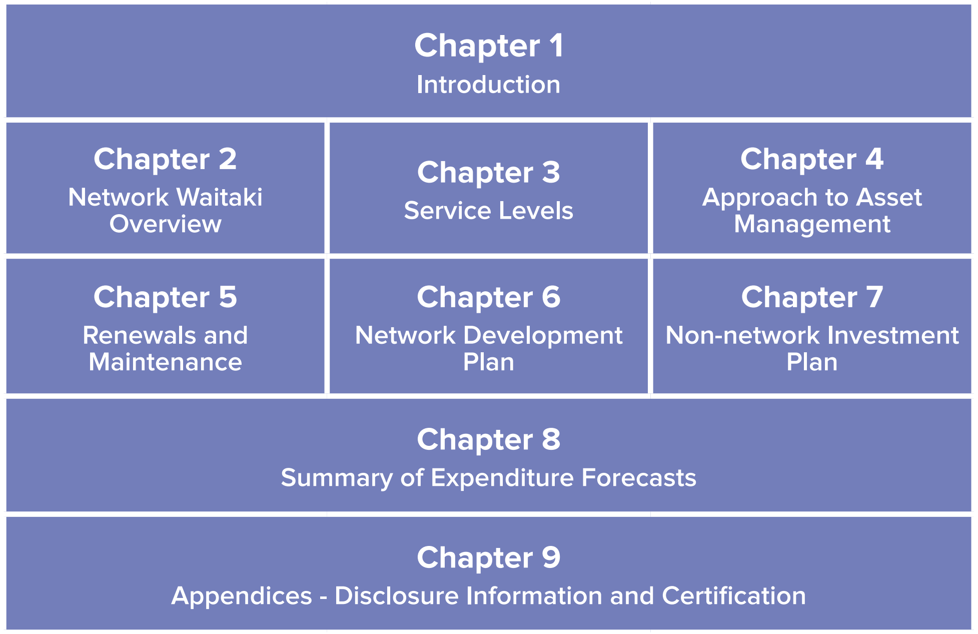


Figure 2 - Structure of Network Waitaki's AMP

1.7 Use of constant dollar values

Capital and operational expenditure values are expressed in constant 2022 dollars. We have not included an adjustment for inflation in order to allow for better comparison of expenditure between years.

1.8 Approval date

The 2023-2032 AMP was approved by the Network Waitaki (NWL) Board of Directors on 27 March 2023. See **Appendix D** for a copy of the signed Certificate of Approval.

Network Waitaki Overview

02

02

Network Waitaki Overview

This chapter describes who we are, what we want to achieve, and is structured as follows:

- **Our company:** outlines our corporate objectives, organisational and governance structures.
- **Operating environment:** an overview on the issues that have an impact on us and our approach to asset management, such as geography, vegetation management, and changes in demand.
- **Stakeholders:** this section describes who our stakeholders are, their interests and expectations, and how these interests and expectations are accounted for in our asset management practices.
- **Our customers:** an overview of our customers, including total number of connections; our major customers and their impact on network operations and our asset management objectives; and the load characteristics of our network.
- **Our network:** an overview of the network including coverage areas; the extent it is overhead and underground; and our substation arrangements.
- **Our Assets:** a population summary of our assets by category.

2.1 Our Company

Network Waitaki (NWL, or the Company) operates predominantly as an Electricity Distribution Business (EDB) in the Waitaki District and parts of South Canterbury. We operate an electricity distribution network (the subject of this AMP), a fibre network, a metering business, public electric vehicle chargers, and provide private electricity network services to some major customers. We also have a contracting division which undertakes distribution, construction and maintenance activities, including the provision of specialist electrical services and vegetation management services. Our contracting division primarily undertakes work for the Network Waitaki network, as well as providing services to other asset owners and contractors.

2.1.1 Ownership structure

NWL is 100% owned by the Waitaki Power Trust (the Trust). The shares of NWL are held on behalf of the NWL consumers (our connected customers) by the Trust, who appoint directors to the Board to carry out the governance functions of the business. The Trust has five trustees. Every three years, three trustees are elected by consumers connected to the network.

In 2021 the Trust carried out a 10 yearly ownership review of the Company. This included an independent review of the ownership options available, with the goal of delivering the best outcome for Network Waitaki's customers. The recommendation of the independent review was that continued Trust ownership is the most suitable model for Network Waitaki.

Subsequent engagement with customers and other stakeholders as part of the ownership review resulted in high levels of support for the Trust ownership model, with over 99% of respondents supportive of the Trust ownership model.

Based on this work the Waitaki Power Trust will retain the total shareholding of Network Waitaki Ltd in Trust on behalf of the electricity consumers connected to the network.

2.1.2 Mission statement and corporate objectives

Our mission statement and corporate objectives are published in our statement of corporate intent (SCI) and provide direction as to how we operate the company, including our asset management practices.

Our mission statement is:

"Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers."

Our corporate objectives cover four areas, covered in the following sections.

2.1.2.1 Health and safety

Our commitment to health and safety is paramount, with the goal of causing no harm to our people or members of the public as a result of our operations. This commitment puts health and safety issues front of mind in every operational decision, from planning a new zone substation down to driving to a work site or opening a low voltage cubicle on the side of the road.

To meet this objective, we provide our staff with training in areas such as risk management, safe driving, work site planning, and safety in design. We ensure that our crews are properly equipped with high quality tools, plant and personal protective equipment, and the training to use it efficiently and safely.

2.1.2.2 Our people and culture

Our goal is to be the employer of choice in North Otago and amongst our industry, in order to attract and retain top talent. We believe that a well-motivated, competent workforce is one of the most important facets of effectively and efficiently delivering a safe and reliable network service.

We train and develop our people across the business to make sure that we are aware of up-to-date practices, and that we will have the ability to deliver on our work plans. We employ trainees and graduates and offer scholarships for tertiary education to encourage locals to enter our industry. The size and skills of our workforce are considered as part of our AMP planning process, so that we have the capability to deliver on our work plans.

2.1.2.3 Our customers and community

We aim to provide our customers with safe, reliable, cost effective and innovative energy solutions, with top tier performance in our peer group. This will enable us to be supportive of activities that provide economic growth and wellbeing in our network area and make us the best choice for our customers when they are examining options for their needs.

We believe that Trust ownership provides the best value to our customers, and that it allows us to deliver them a modern, reliable, effective electricity network with the best possible efficiency.

2.1.2.4 Building a sustainable future

it is important that we operate our business in a commercially sustainable manner and to continually improve the efficiencies of delivery. It is important to preserve and grow the value of the business, which will provide income to fund the discounts and community support activities that we provide to our customers, and ensure that the long-term future of our stewardship of the electricity assets is secure.

We aim to minimise the impact of our operations on the environment and ensure compliance with the Resource Management Act, and to comply with all obligations under relevant legislation and regulations. This includes the promotion to our customers of the efficient use of energy.

2.1.3 Organisation structure

The Trustees of the Waitaki Power Trust appoint Directors to our Board to govern the company, who in turn appoint the Chief Executive. Ultimate accountability for the performance of the business, including the network assets, lies with the Board who approve this AMP. The Board are also accountable to the Trustees for meeting the requirements set out in the Statement of Corporate Intent (SCI), which includes specific safety, performance, asset management objectives and service targets.

The Chief Executive and the management team report to the Board on a monthly basis, updating them on risks, performance, and work programme progress. Quarterly reports comparing year-to-date performance against the SCI are provided to the Trust. Annual reports are prepared by both NWL and the Trust.

Our staff are organised into functional teams to ensure that operation of the network and delivery of our works programme are efficiently delivered. Most of the annual works programme is undertaken by our integrated contracting business unit, which has a staff of about 60 people in Oamaru and Cromwell. Specialist skills are contracted in when required.

2.1.4 Asset management governance

Asset management responsibilities are allocated between the senior staff as follows:

Chief Executive

The Chief Executive is accountable to the Board to ensure that the strategic objectives of the Board and the Trust are delivered.

Chief Financial Officer

The Chief Financial Officer is responsible for the financial activities of the company, including preparation of annual budgets for operating and capital expenditure with input from all areas of the business, as well as providing reports that enable financial performance of works programmes to be monitored against budgeted costs.

General Manager Network

The role of General Manager Network provides leadership, coordination, and oversight to all aspects of operating the Network, including asset management, network development, and network operations. The role coordinates resources across multiple teams to deliver the outcomes of the AMP and this person is a key figure in driving continual improvement of our asset management practices.

Network Lifecycle Manager

The Network Lifecycle Manager is responsible for development of the asset management processes and systems, the development of standards and policies, and that projects and programmes of work are initiated to address performance, safety, and reliability risks on the network.

Network Development Manager

The Network Development Manager is responsible for the planning and evolution of our network to ensure we can enable our customers' desires. This includes understanding our customers' future needs, evaluating options, and selecting the best options to enable these.

Engineering Manager

The Engineering Manager has responsibility for the day-to-day operation of the network and the efficient and timely delivery of the annual capital and maintenance work programmes.

Health, Safety and Risk Manager

The Health, Safety and Risk manager is responsible for the management of health and safety systems and public safety systems. This includes setting performance initiatives to measure and monitor the effectiveness of critical controls and ensuring risk owners are regularly reviewing and updating their risks.

Regulatory Manager

The Regulatory Manager is responsible for the preparation of regulatory disclosures, compliance, and pricing.

Customer and Community Relations Manager

The Customer and Community Relations Manager is responsible for leading our customer services function and developing and maintaining the interface between the company and the community and other stakeholders.

General Manager Contracting and Operations

The GM Contracting and Operations is responsible for the provision of construction and maintenance staff and equipment in order to complete the annual works plan in those areas of service provided by our in-house contracting team. This person is also responsible for seeking out and managing any work outside our network for other network companies or private customers.

People and Culture Manager

The People and Culture Manager is responsible for human resources strategy and management systems associated with appropriately managing our human capital. This includes identifying our current and future capability and skill gaps, then helping to develop and implement strategies for access and delivery of the required capabilities and skills.

2.1.4.1 Expenditure approvals

Operational and capital budgets are prepared annually and approved by the Board. For larger projects, investments in new areas, and projects committing the company to expenditure over several years, the approval process includes a formal business case. This provides the Board with an overview of the risk, options considered, and the economic assessment of the proposed solution.

All roles within the company are subject to approved delegated financial authorities. Any expenditure beyond these limits requires specific approval from a manager or the Chief Executive or the Board, depending on the absolute amount of the expenditure.

2.1.4.2 Asset management capability and delivery

Our organisational and governance arrangements are structured to ensure that we have the necessary capability to implement this AMP. We ensure that our AMP work programme can be achieved by tracking our progress with regular reporting and review of the physical and financial progress of the work programme against our plans and budgets. This reporting also includes operational metrics such as SAIDI and SAIFI.

Planning of the delivery of the AMP in any given year balances the requirements of the business to complete particular works programme items (e.g., risk, capacity constraints, customer requirements) against our ability to efficiently deliver the works plan. The goal is to develop a works programme that is well balanced across the planning period and to avoid major peaks and troughs in work so that our resources can be well matched to the programme. The network then benefits from having a stable, experienced, and efficient workforce, without the need to upsize in busy years or downsize in quieter years. Within this plan, this is reflected in the phasing of some renewal and maintenance category budgets towards the later part of the planning period. We know the total amount of work (e.g., switchgear maintenance and renewal) that we need to complete over the planning period and have coordinated the allocation of that work across individual years in order to smooth the delivery work stream around fixed workstreams such as major line builds and new substations.

Delivery of the bulk of the AMP is provided via our internal Engineering and Contracting teams. The skill set of our Contracting team is generally focussed on the core line construction and maintenance roles, including live line work, cable jointing and line construction. Specialist experience such as communications and power technicians are traditionally contracted in as required from external providers who we maintain strong relationships with.

We have recently extended our field capability with the development of vegetation management and electrical services teams within our contracting business. These services were previously contracted out, and so this will reduce our dependency on external providers and is expected to increase the efficiency and quality of the work in these two areas of service delivery.

The sustainable delivery of our AMP requires the ongoing availability of suitable skills within our Contracting team. We recognise that the average age of staff in many of our departments is increasing, and we are at risk of a future skills shortage as these people retire. To address this, we are investing in developing new resources by bringing on board Contracting trainees, trade apprentices and providing scholarship opportunities for technical education. These developmental initiatives are factored into the overall delivery of the AMP.

Sustainable delivery also requires that we balance the works programme to efficiently use our available resources, while still meeting the requirements of the plan. In practice this means that we will choose to schedule large projects across the planning period to avoid peaks and troughs in planned work in areas where we expect our own field teams to deliver. When this levelling is combined with capital intensive activities that do not require our internal resource (such as purchase of a new zone substation transformer) it can result in what appears to be a "peaky" works programme, when considered strictly on an expenditure basis. Where peaks are unable to be met with our contracting team, we will engage other contracting resources to supplement our existing resources.

We monitor, report and correct progress to the AMP at various levels within the business. Project level reporting is the domain of our Project Engineers and Supervisors, who are tasked with keeping individual jobs on track. Progress against major projects and programme level activities such as inspections is monitored by department managers. Programme level financial and status reporting is monitored at Chief Executive and Board level.

Review of these practices has shown that although this reporting gives us good awareness of the historical performance against the works programme budgets, there is room to improve how we forecast ongoing delivery of the works programme, which would create opportunities for efficiency in areas such as resource scheduling. Key areas in our strategic plan target improvements in the area of project management practice, financial monitoring and reporting and forward scheduling of the work programme.

As a small, tightly knit, flexible company we regularly adjust the work programme and coordinate work to take advantage of other activities in a particular area, such as a planned outage, to respond to a particular driver such as a weather event or meeting a customer's unexpected requirements. Exercising this flexibility while still maintaining delivery of the overall AMP is a key focus of our staff.

2.2 Our Position on Climate Change

We acknowledge the science behind climate change and support New Zealand's carbon zero goals. We see that we have a key role in enabling those goals and have incorporated these into our mission and values.

The electricity sector will play a key role to enable process heat and transport to move away from carbon-based energy.

The recent Boston Consulting Group report[1] identifies that "roughly 30% of New Zealand's gross emissions come from sources that can be decarbonised by the electricity sector" and that $22 billion needs to be spent "in the 2020s to prepare networks for rapid electrification and multi-directional flows of electricity in the 2030s".

Last year we worked with EECA, Transpower and Deta to produce a review of the process heat decarbonisation opportunities in our area. We are currently working with a large industrial customer who has committed to converting to electricity next year and we are working closely with another large coal user who we expect to convert between 2027 and 2030. We provide further details on decarbonisation assumptions in **Section 6.4 – Our demand scenario assumptions**.

The two main climate change network issues for us to focus on are ensuring we:

- Continue to develop the capability to operate and effectively grow the distribution network to meet increased demand arising from decarbonisation
- Manage the effects of increased extreme weather events impacting our network infrastructure and systems.

We discuss our plans to manage the first issue and evolve our network infrastructure and systems to enable decarbonisation of transport and connection of distributed generation in **Section 6.2 – Our network evolution roadmap** – and we present our investment plans to enable process heat decarbonisation and general network growth in **Section 6.8 – Network development projects.**

For the second issue, we are monitoring climate research and, as we learn more, will update our practices to ensure we can adapt to these. Currently we have seen research giving high level projections for areas. We have discussed some of these projections below in this section.

[1] Boston Consulting Group – The future is electric – October 2022 https://www.bcg.com/publications/2022/climate-change-in-new-zealand

One of the areas we have yet to address is the impact on our infrastructure from extreme weather events. Cyclone Gabrielle has highlighted significant consequences to lifeline utilities providing services to the communities. We will be reviewing and taking learnings from those involved over the coming months.

We are also currently engaging with NIWA, other EDB's and critical infrastructure groups to co-ordinate understanding and impacts of extreme weather events on critical infrastructure to understand both impact ofn the infrastructure and impact on our ability to respond. This research and modelling is expected to occur over the next two years.

Currently we are working with NIWA and FENZ to introduce new fire risk monitoring systems of the current local fire conditions so we can adapt our operating practices in real time. We are also collaborating with peer EDBs to create a new overhead line design standard and as part of this will work with NIWA scientists to review projected climate conditions for our area.

The Ministry for the Environment have produced climate change projection scenarios for 2040 and 2090[2], compared with a baseline of 1995 and we have presented these below with high-level comments on the impacts we expect in our area.

Temperature

Compared with 1995, temperatures are forecast to be 0.6˚C to 0.9˚C warmer by 2040 and 0.6˚C to 2.8˚C warmer by 2090.

By 2090, Otago is projected to have up to 25 extra days per year where maximum temperatures exceed 25˚C, with around 13 to 45 fewer frosts per year.

The rise in ambient temperature will marginally reduce the operating range for thermally rated equipment such as transformers and overhead lines. We do not expect this to have a significant impact on the capacity of our assets, but will take this into consideration as we review our standards for design of long-life assets.

Rainfall

Rainfall will vary locally within the region. The largest changes will be for particular seasons rather than annually.

Otago is expected to become wetter, particularly in winter and spring. Seasonal projections show winter rainfall increasing by 4 to 10 per cent in Dunedin and 4 to 27 per cent in Queenstown by 2090.

According to the most recent projections, extreme rainy days are likely to become more frequent in Otago by 2090 under the highest emissions scenario.

This may have an effect on timing and magnitude of irrigation demand but is not expected to have an impact over the planning period.

Snowfall

The Otago region is likely to experience a significant decrease in seasonal snow. By the end of the century, the number of snow days experienced annually could decrease by as much as 30-40 days in some parts of the region. The duration of snow cover is also likely to decrease, particularly at lower elevations.

Less winter snowfall and an earlier spring melt may cause marked changes in the annual cycle of river flow in the region. Places that currently receive snow are likely to see increasing rainfall as snowlines rise because of rising temperatures. For rivers where the winter precipitation currently falls mainly as snow and is stored until the snowmelt season, there is the possibility of larger winter floods. This may have an impact on river flows and the water available for irrigation usage, which could impact on the way irrigation is used in our region.

Overhead power lines that are inland to the west of Kurow are subject to damaging snow falls every few years on average and changing patterns of snowfall may reduce this. We will continue to construct our lines for the present design snow loadings, but will keep a watching brief on projections.

Wind and storms

The frequency of extremely windy days in Otago by 2090 is likely to increase by between 2 and 5 per cent. Changes in wind direction may lead to an increase in the frequency of westerly winds over the South Island, particularly in winter and spring.

Future changes in the frequency of storms are likely to be small compared to natural inter-annual variability. Some increase in storm intensity, local wind extremes and thunderstorms is likely .

As part of our new overhead line design standards, we will work with NIWA to review our wind loading assumptions.

[2] Source:2018 '2nd Edition' of Climate Change Projections for NZ https://environment.govt.nz/publications/climate-change-projections-for-new-zealand/

Sea level rise

New Zealand tide records show an average rise in relative mean sea level of 1.7 mm per year over the 20th century. Globally, the rate of rise has increased, and further rising is expected. For new assets we will consider potential effects from climate change, such as sea level rise, increased coastal erosion, and inundation, when we are selecting the location and construction style of the asset.

2.3 Our Operating Environment

2.3.1 Present environment

The operating environment of the Waitaki region is a mixture of coastal plains and alpine areas.

The climate is traditionally dry and cold in winter, and dry and hot in summer. The area is known to suffer from drought.

Extreme weather events can include wind and snowstorms, and floods. We expect to experience at least one significant weather event every year. The impact of these events is typically restricted to the inland area of the network, but can occasionally affect the whole region, and in extreme events can affect neighbouring regions as well.

The coastal conditions are comparatively benign with a fairly small zone where equipment corrosion is a concern, although coastal erosion is starting to impact in some areas of the region, with some local road networks being affected. We are monitoring these situations with respect to our assets in the specific affected areas.

The major urban population is centred on Oamaru, a coastal town of approximately 13,900 people located on the east coast of the South Island. The population of the wider Waitaki region is about 22,300.

There are several small townships in the region, most of which are on the two state highways that run North to South (SH1) and East to West (SH83) through the region.

The rural economy is based on a mixture of beef and sheep farming, crops, and dairy. Irrigation is used widely , via schemes that include border-dyke systems, direct pumping from local water sources, or reticulated systems to the farm gate. Irrigation is a major source of growth on our network. The Ministry for Business, Innovation, and Employment records that the contribution to the regional economy from the agriculture sector was 15% of GDP in 2017 (most recent published figures)[3].

There is also a significant manufacturing sector in the region, contributing approximately 11.5% to the regional economy in 2017.[4]

Despite the typically dry summer conditions, vegetation growth is robust throughout most of our network, and management of vegetation near our assets is an ongoing focus of operations.

2.4 Regulatory Environment

2.4.1 Pricing

It is vital that we can sustainably deliver this Asset Management Plan. To ensure this sustainability we have developed a financial model that allows us to view the impact of the required investment over the planning period and beyond under various growth and asset renewal scenarios. This model is used to plan an appropriate portfolio of funding sources considering the estimated useful life of the investment, the major beneficiaries, and the concentrated nature of some system growth investments.

From an economic regulation perspective, Network Waitaki is subject to regulation by the Commerce Commission under Part 4 of the Commerce Act 1986. As Network Waitaki meets the ‘consumer-owned’ criteria set out in section 54D of the Commerce Act, the company is exempt from price-quality regulation. However, compliance with information disclosure regulation is still required, and we are conscious that we must deliver good value to our connected customers in terms of a price of service vs. quality of supply.

Network Waitaki is furthermore subject to regulations set by the Electricity Authority as the electricity market regulator, responsible for the efficient operation of the New Zealand electricity market. One of the focus areas of the Electricity Authority is improvement of efficiency of distribution prices to become more cost-reflective, especially with new technologies entering the market and changing the way electricity is consumed and produced.

As a wholesale provider of electricity distribution services, we recognise that there is a mismatch between our pricing structures, which generate much of our revenue through volume-based prices, and our costs, which are essentially fixed.

[3] Source: MBIE Regional Economic Activity Web Tool. http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018
[4] Source: MBIE Regional Economic Activity Web Tool. http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018

For this reason, we are adjusting our pricing structures on a staged basis, the ultimate aims of which are to:

- Reflect the cost of service more accurately through a better balance of the fixed and volume-based components of electricity distribution prices, thereby assuring the sustainable delivery of a reliable and safe service.
- Safeguard revenue reliability through implementation of cost-reflective price structures.

2.4.2 Climate change policy

The Climate Change Response (Zero Carbon) Amendment Act 2019 sets New Zealand’s emission reduction targets at zero net greenhouse gas emissions by 2050 (excluding biogenic methane) to contribute to achieving the Paris Agreement goal of limiting global warming to well below 2, preferably to 1.5, degrees Celsius, compared with pre-industrial levels.

Our position on climate change is presented in **Section 2.2**.

2.5 Stakeholders

2.5.1 Stakeholders and their interests

Our stakeholders are the people or organisations that can affect, be affected by, or perceive themselves to be affected by our decisions or activities. Stakeholder requirements are an important driver for our performance, and we place considerable focus on identifying and meeting stakeholder expectations. Our stakeholders are described in Table 3 below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Table 3 - Network Waitaki stakeholders

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
Customers	Health and safety; reliability; value for money; effective communication, particularly during emergencies and faults; emergency and lifeline preparedness.	Bi-annual customer surveys – a revamped survey was completed in 2021 and will be rerun in early 2023; face to face meetings with major customers; feedback sought after work or major outages; public safety performance measures.	Maintaining audited Public Safety Management System and other safety initiatives; price/quality trade off; network development plans; investment planning; asset lifecycle management.
	Ensuring appropriate network provides for customer needs	customers; feedback sought regarding customer service levels, proposed future requirements.	Recognise energy affordability issues and regional development opportunities.
Staff and other workers	Healthy, safe and enjoyable work environment; job satisfaction; assurance of work continuity; visibility of forward workload requirements; work/life balance; career development opportunities; fair remuneration; effective support.	Staff feedback; regular staff briefings and communications; staff input into decisions affecting work environment and methods.	Health and safety initiatives and reporting; integration of risk management into all business processes; forward planning of work.
Public, and landowners	Health and safety; emergency and lifeline preparedness; protection of property and amenity values; effective communication regarding access and maintenance.	Meetings; feedback; consultations.	Health and safety initiatives; emergency preparedness planning; service levels.
Board of Directors	Governance; risk management; health and safety performance; business direction and sustainability; Performance of Chief Executive; statutory and regulatory compliance.	Regular board meetings and directives; performance measures.	Integration of risk management into all business processes; regular reporting.

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
Waitaki Power Trust	Fair and reasonable rate of return on equity; incentives to invest and innovate; good governance; risk management; business sustainability; good reputation with the community; effective asset management	Trustee meetings; performance measures.	Network development planning; investment planning; asset lifecycle management; organisation and governance structures; integration of risk management into all business processes; quarterly and annual reporting.
Councils	Alignment with district and regional requirements; statutory compliance.	Meetings; consultations on regional and district plans.	Network development planning for system and demand growth.
Iwi	Ensure participation to enable responsible stewardship of the environment.	Understand and respect the importance of equity and build relationships with local Iwi and Runanga.	Ensure processes adequately cater for recognition of cultural and governance of our impact on local land and resources
Electricity generators and retailers	Safety, reliability, effective communication; statutory and regulatory compliance; fair contractual arrangements; transparency; effective delivery of business-to-business services.	Industry forums, conferences, and seminars; regular consultation, statutory and regulatory requirements; contractual arrangements.	Network development planning; service levels.
Regulators and Governmental Agencies	Statutory and regulatory compliance; ensure our connected customers receive a reliable supply of electricity accounting for price/quality trade off; compliance with health and safety requirements.	Statutory and regulatory requirements; consultations; industry forums, conferences, and seminars.	Network development planning; service levels; risk management; governance arrangements; inclusion of safety-by-design principles.
Transpower (as grid owner and System Operator)	Security of supply; new grid investment and planning provisions; effective and timely communication; statutory and regulatory requirements; sustainable earnings from connected and interconnected assets.	Operational standards and procedures; regular meetings.	Network development planning; investment planning; asset lifecycle management; risk management.
Neighbouring EDBs	Coordinated investigation into shared transmission constraints, opportunities for sharing common operating standards and practices.	Meetings/participation in working groups to discuss and undertake collaboration opportunities.	Decisions will be incorporated in future Network Development Plan, Network Design and Operating standards and Practices.

2.6 Our Customers

2.6.1 Major customers

Our major customer groups are urban-residential around Oamaru and other townships, and large rural farming customers (typically dairy and cropping). We have a small but important level of commercial and industrial demand on our network and our top 10 customers by volume of energy consumption operate in the industry categories below:

- Meat processing
- District irrigation schemes
- Council utilities and infrastructure
- Supermarkets
- Food manufacturing

We aim to engage with our customers regularly to understand their needs to enable us to better provide a reliable network to meet those needs. We also look to engage when we are planning work that involves a power outage, so we can minimise disruption to their operations.

2.6.2 Maximum demand and energy delivered

A comparison of the network maximum demand and energy delivered since 2011 is presented below. This is separated into winter (June, July, August) and spring /summer/autumn to remove the effect of irrigation from the winter data.

Winter maximum demand and energy delivered are trending upwards at 1.1% per year. Variability from year to year is influenced by winter temperatures and associated changes in heating demand.

Maximum demand for the remainder of the year has increased by 3.1% on average each year (up to FY21) and energy delivered by 2.8%. This is largely driven by irrigation growth. FY22 figures were lower due to wetter than average spring and early summer conditions which is when we typically experience maximum demand.

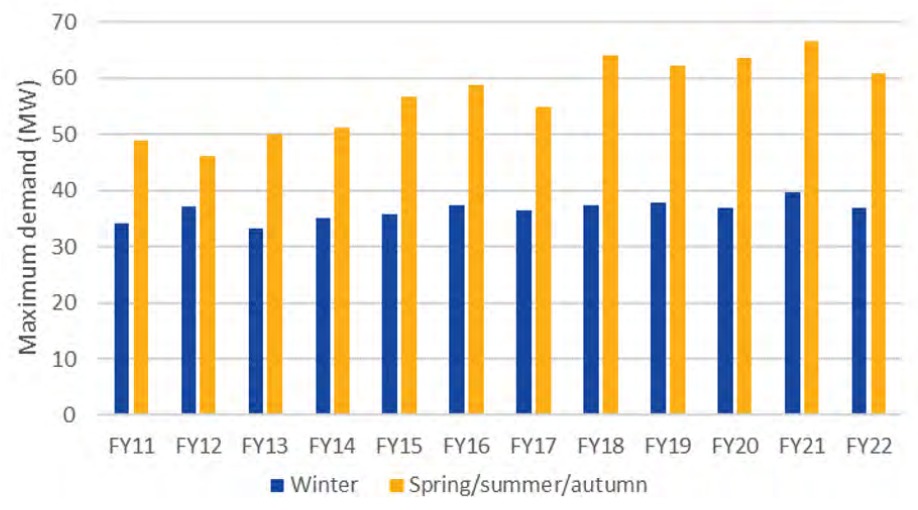


Figure 3 – Historical total network maximum demand

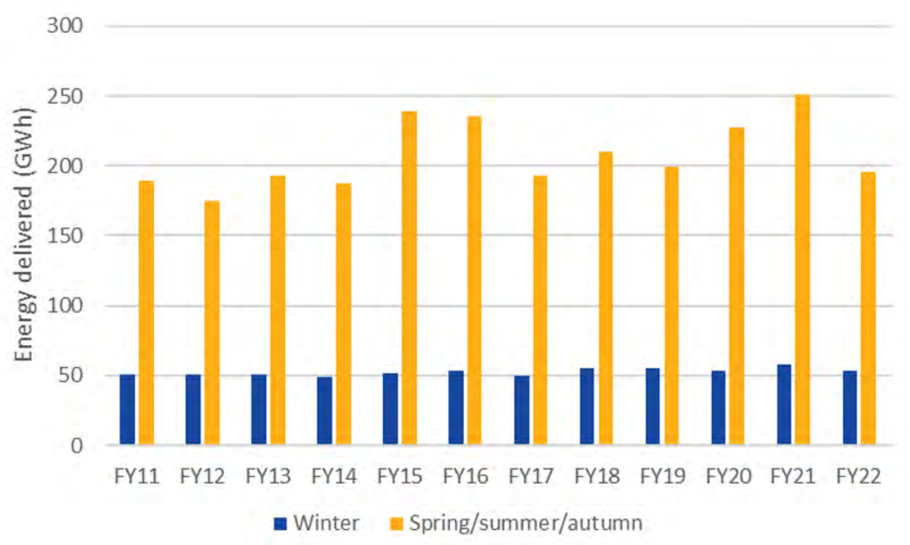


Figure 4 – Historical total network energy transported

2.7 Overview of Our Network

We operate a predominantly overhead rural network supplying the North Otago, Hakataramea, and Ahuriri regions as shown in Figure 5 below. We supply one major urban area, Oamaru, and several smaller townships.

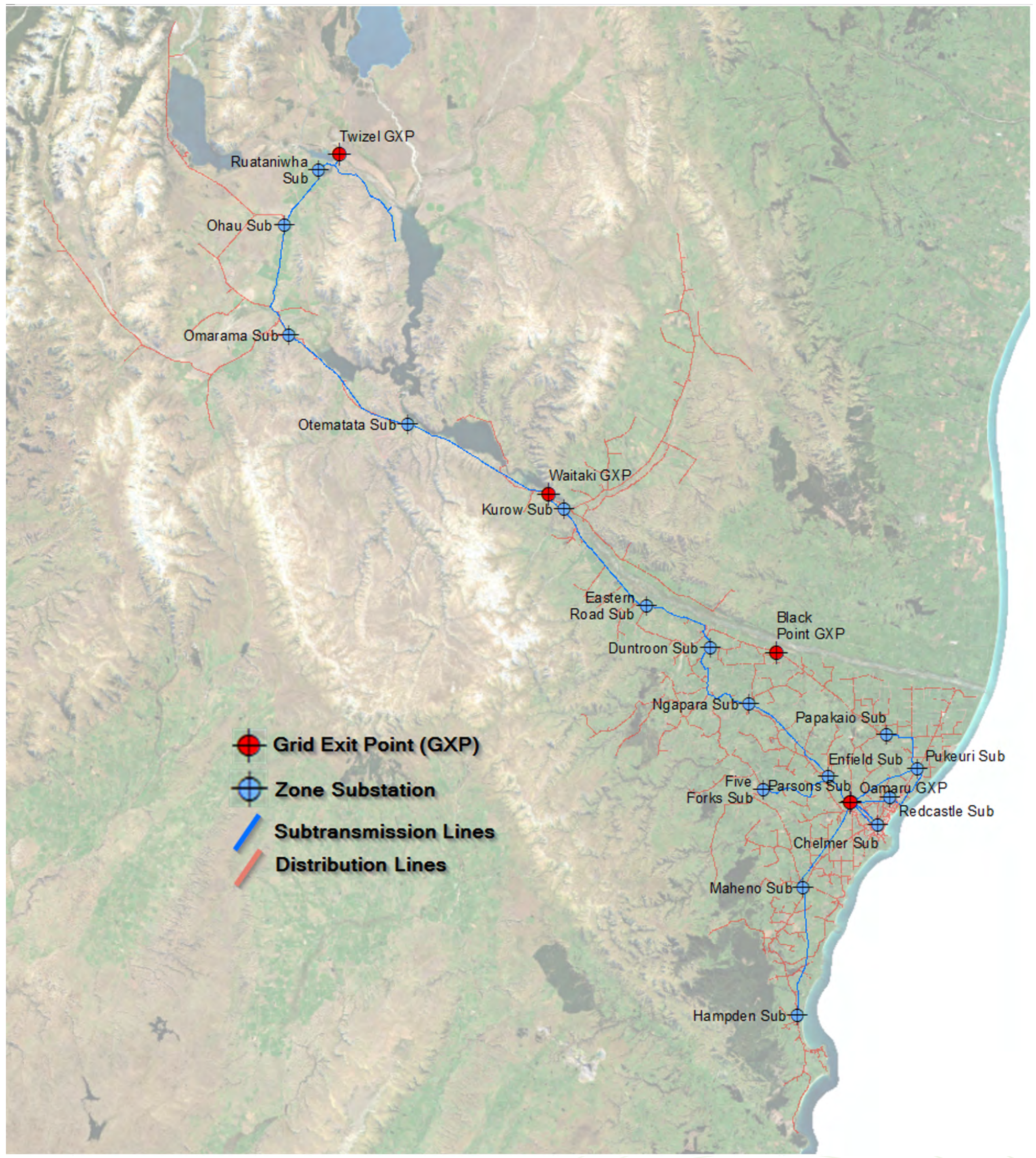


Figure 5 - Map of NWL area of supply and network extent

Bulk supply of electricity is taken from Transpower's network (the national grid) at our four grid exit points (GXPs). This energy is then transported via our sub-transmission network at 33,000 volts (33 kV) to the zone substations. Power transformers at the zone substations convert the 33 kV supply to a lower distribution voltage of 11,000 volts (11 kV) which is supplied to some customers directly (generally large commercial and industrial customers) but is more commonly stepped down via distribution transformers to our low voltage system (400 volt, three phase/230 volt single phase), which supplies most of our customers.

The characteristics of our grid exit points (GXPs) are listed in the table below:

Table 4 - Characteristics of NWL grid exit points as of 31 March 2022

Grid Exit Point	Voltage	Security	Capacity	Max demand FY22 (Non-Coincident)	Zone Substations supplied
Twizel GXP	220/33 kV	N-1	27 MVA	3.1 MVA	3
Waitaki GXP	11/33 kV	N	24 MVA	11.0 MVA	4
Black Point GXP	110/11 kV	N	25 MVA	15.7 MVA	0
Oamaru GXP	110/33 kV	N-1	45 MVA	36.8 MVA	10

A 33 kV sub-transmission network connects the GXPs to our zone substations. The 33 kV sub-transmission network is predominantly overhead construction, apart from a few short cable sections.

2.8 Our Assets

Table 5 - Key features of NWL network

Parameter	Value
Number of poles	21,606
Length of 33 kV lines and cables	238 km
Length of 11 kV lines and cables	1,339km
Length of LV lines and cables	326 km
Number of zone substations	17
Number of connected customers	13,282
Coincident max demand	61 MW
Annual energy delivered to customers	238 GWh

These assets are discussed in more detail in **Section 5 - Renewals and Maintenance**.

Service Levels

03

03

Service Levels

This chapter provides an overview of our network performance, its impact on our customers, and our targets for improving customer outcomes.

3.1 Introduction

3.1.1 Overview

This chapter outlines our performance and targets for the planning period.

There are three areas of focus:

- Health and safety
- Customer experience
- Network performance

3.2 Health and Safety

We are committed to ensuring that our network always remains safe and seek to actively manage risks to members of the public, public property, and our staff. To facilitate safe outcomes, we are focused on

- building capacity of our staff by developing skills and knowledge
- good policies and processes that are easily understood and workable
- providing quality and maintained structures, plant, and equipment
- educating and informing the public and businesses about our network
- collaborative learning and education with emergencies service providers and other businesses
- learning and continuous improvement.

We maintain an audited Public Safety Management System (PSMS) where we document known and likely hazards and risks to the public, along with the controls used to resolve them (eliminate the risk, or minimisation of the risk or likelihood of it occurring). This system is audited annually both externally and internally against the standard NZS7901:2008 Electricity & Gas Industries Safety Management Systems for Public Safety. The external audit provider is Telarc, who are authorised to audit against NZS7901:2008 standard. The outcomes of the audit process are analysed by our staff to make improvements to the PSMS and how we use it.

3.2.1 Health and safety objectives

Our overall objectives are determined by our strategic plan and through our health, safety, and wellbeing plan. Our objectives are to ensure that staff, workers, the public, and their property are safe and free from harm due to the operation of our network and work activities. We will not compromise the health or safety of our staff, workers, the public or their property.

In summary, our safety objectives are:

- Safety is integrated in all aspects of our business.
- Staff, workers, and the public are not harmed due to the operation of our business.
- A positive organisational culture is promoted amongst all our staff and workers.
- Any identified health and safety risks are assessed for risk, prioritised, and mitigated as soon as possible.

3.2.2 Measures and targets

- Monitoring of health and safety performance with targets, such as
    - the number of safety observances or site audits (leading indicators)
    - third party, independent consultants to review work practices against industry practices and training
    - monitoring the implementation and effectiveness of health and safety critical risk controls
    - monitoring and assessing contractors and suppliers
    - incident trend analysis to identify emerging health and safety trends for action
- Monitoring indicators of organisational impacts, such as
    - total work hours within a given period and the number of times staff have worked to the stage where they need to stand down for rest breaks (leading indicators)
    - the amount of sick leave and ACC hours taken across the whole company (lagging indicators)

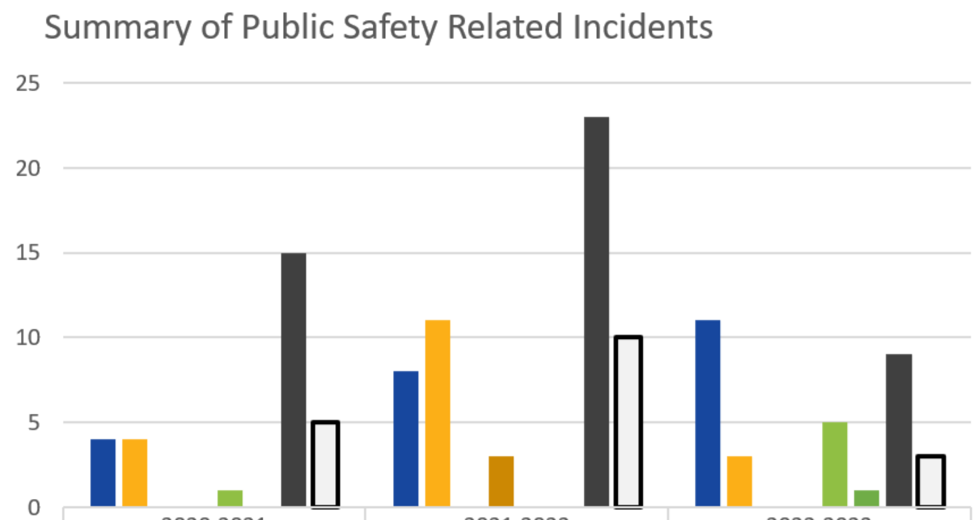
- Monitoring the number of incidents and accidents on our network involving the public.
- The number of public information and education activities.
- Annual certification to NZS7901:2014 for our Public Safety Management System – using Telarc as independent auditors.
- Progress towards certification to ISO45001 Health and Safety Management Systems with Telarc.
- Independent, third part audits and reviews of compliance, risks, and crucial systems.
- Monitoring mitigation of specific risks e.g., the removal of red tag poles from the network.

3.2.3 Performance

Historically the measurement of safety performance has focussed on lost time injuries and incidents reported for our workers.

We also measure and monitor public incidents and accidents on our network, as shown in the table below:

Table 6 – Summary of public safety related incidents and accidents



	2020-2021	2021-2022	2022-2023
Rural Activities	4	8	11
Construction Activities	4	11	3
Trades		0	0
Recreational	0	3	0
Customer Activities	1	0	5
Vandalism/Ignorance		0	1
Vehicles	15	23	9
Network Asset	5	10	3

Table 7 - Public Safety Performance Targets

Objective	Target	Performance
Unauthorised Network Access	0	0
Injuries to the Public from Network Operations	0	0
Significant damage from Network Operations	0	0

As can be seen from the figures, the annual number of incidents involving the public has been consistent over the extended period with an increase in FY22. This may be attributed to improvements in reporting and recording of public related incidents. The bulk of the incidents remain to be vehicle accidents with poles and other ground mounted equipment. There has been an overall decrease in all incident classifications. We will continue to monitor these areas of public safety to identify any trends where we can intervene with public awareness, training, or targeted improvements to the network.

Continuous review of the input/output of information allows better trending of potential issues and focus areas. A Health and Safety report is tabled and discussed at each monthly Board meeting, Health and Safety Committee meeting, management meetings and staff meetings which includes performance figures against our goals. This is to ensure all staff have good knowledge and understanding of our public safety responsibilities and how they contribute to the success of our objectives.

3.3 Customer Experience

3.3.1 Overview

We will see significant changes in the electricity sector in the next twenty years as our customers take up new technologies and decarbonise their businesses and transport. We are committed to enabling our customers future energy needs while being mindful of security, sustainability, and affordability.

To enable our customer's future, we must create a customer experience framework that is both robust and scalable to meet the ever-changing environment we are moving within in line with our Mission, Vision, and Values.

Engagement to understand our customers and stakeholders primarily occurs with surveys, face to face meetings, attendance at public events such as agricultural field days, industry forums and conferences as well as actively participating in industry consultations relating to statutory and regulatory changes, and Regional and District Plans.

To enhance our ability to service our customers, we have three customer centered projects that have commenced to create this enhanced customer experience foundation that will enable us to understand our customers vision of their current and future needs.

On occasions our customers may not be happy about a particular situation, or with the service that they received. When do not meet the expectations of our customers we seek to work with them to resolve any issues whilst also ensuring they are aware of the free and independent service offered by the Utilities Disputes Scheme.

3.3.2 The customer experience journey

The strategy is to create a human connection to our customers and better understand their experience of what we deliver today that will drive the experience in the future.

Human Connection and Empathy –

- Understanding and communicating who our customers are and building empathy to change how interactions are delivered.
- Measuring customer experience at an interaction level rather than a brand perception level.

This project identified drivers of customer effort and the findings are being utilised in helping us re-engineering our future delivery of customer services.

3.3.3 The voice of our customers

We are seeking to improve our customer experience to meet our customer and community's increasing expectations, to not only drive process efficiencies, but to also establish the foundations of a customer centred service that will enable us to deliver an improved customer experience at scale and at the right costs.

We have investigated ways we can gather customer/community feedback (positive/negative) to gain an understanding of how they feel when interacting with NW. This will help us establish what is important to our customers, what we do well, what we can improve on etc. and allow us to make improvements in the right areas and achieve our Business Strategy - especially around our core systems and processes and customer focus.

A Proof of Concept has been completed for an automated Voice of Customer system with the results showing the system can provide a detailed and easy to use tool that enables us to gather data, analyse and report on what matters. The success of the pilot has resulted a decision to implement the system into our processes to enable ongoing consistent monitoring of our customers satisfaction levels.

3.3.4 Customer service benchmarking

We undertake a 2 yearly survey of our customers. A total sample of 410 urban and rural customers are interviewed by telephone with a further 20 face-to-face interviews undertaken with large commercial customers. All interviews are conducted using an interview guide and using a reasonably standardised set of questions to ensure comparability, this enables us to benchmark our performance relative to other EDBs and to measure performance and improvement going forward.

The intention of the survey is to include all aspects of the customer experience from awareness and recognition, quality of service, to delivery, price and quality of interaction with Network Waitaki. The objectives of this research are:

- To understand customer's perceptions of the organisation, and our reputation;
- To understand satisfaction with the services provided by Network Waitaki
- To identify the key drivers of these perceptions; and
- To identify priority opportunities to enhance customer satisfaction.

A series of comprehensive reports, are compiled by Key Research and presented to the business, identifying industry trends, clear priorities to enhance the customer experience and develop our community presence.

The results are then included in an Industry Benchmark Report that measures key performance indicators of a number of other EDBs to understand customer satisfaction experience with the services provided by the electricity distribution industry.

3.4 Delivery of Customer Service

We are focussed on making it easy for our customers to do business with us. To this end we are utilising information from our customer journey process to help us re-engineering our business processes and improving our use digital systems and data to enable where possible customer self-service, or automating processes to deliver better outcomes.

3.4.1 New or changed connections

Our customers usually advise us of their intention to take a new load or generation connection (or alter an existing connection), by completing our online application form, coming into our office, or calling us on the phone. We endeavour to contact larger customers at least annually to talk about their upcoming energy needs.

When we receive an application, we will accept it immediately if capacity has already been provisioned (for example, in a serviced subdivision) or we will contact the customer to confirm that we understand their needs correctly and can manage their expectations around our response timeframes.

We seek to minimise costs to our customers for new or altered connections by

- having a fair and transparent Capital Contributions Policy
- investigating where non-network solutions may be appropriate to minimise congestion
- offering the option of a controlled tariff for domestic connections to minimise network impacts from hot water load in return for a reduced daily charge (non-network solution)
- modelling the impact of the new load on our network to understand any potential issues
- using standard designs and equipment sizes where network upgrades are required.

If we encounter delays, which may be due to weather, impaired site access, or equipment procurement, we endeavour to keep our customers informed and will place increased priority on this work once the cause of the delay is alleviated. We are currently developing our customer service level targets over FY24 and our draft targets are:

Table 8 - Draft customer service level targets

Type	Location	Network	Acknowledge application (working days)	Offer to customer (working days)	Project deliver after customer acceptance (working days)
General enquiries	All	All	3	15	-
Below 1phase 15 kVA and 3 phase 30 kVA	Urban and township	Existing	3	15	20
Less than 300 kVA	Urban and township	Existing	3	25	120
less than 150 kVA	Rural	Existing	3	25	120
greater than 300 kVA less than 750 kVA	Urban and township	Existing	3	30	As agreed
greater than 150 kVA less than 750 kVA	Rural	Existing	3	30	As agreed
All other connections	All	All	3	As agreed	As agreed

Where connections are likely to have a significant impact on our network, we will:

- Have detailed communication with our customer or their agent (e.g., electrician or consultant) to understand the technical and commercial requirements, and timeframes for their proposed connection.
- Model the impact of the proposed new load on our network, with the complexity of the modelling being determined by the size of the potential impact. We will consult with other EDBs or engage external consultants as appropriate.
- Add customer demand that has been signalled with reasonable certainty into our demand forecasting model.

We manage the risk around the uncertainty of the timing of the customer demand (or generation) by forecasting for three growth scenarios (low, expected, and high) at zone station feeder level. For example, a planned customer development of 1 MVA between 2027 and 2030 may appear in the high demand scenario for 2027, the expected scenario for 2030, and depending on certainty may or may not appear in the low scenario.

3.4.2 Customer outage notification

Included in works delivery processes are notification to our customers of planned outages. Prior to arranging the outages, we will engage with priority customers to manage impact. Once an outage is confirmed, we will directly notify our customers through a variety of communication mechanisms. Mainly this is done through text or email, with letters delivered to any customers not contacted. Any cancellations are implemented through the same mechanisms.

For unplanned outages, we will notify customers through social media of area outages with details of the fault and expected restoration. Priority customers are generally contacted directly. Details are also provided to our operators at the call centres.

With the implementation of improved Network SCADA, Outage Managements Systems and Advanced Distribution Management Systems, this will improve our ability to enhance our customer communications. Refer to **section 7.2.1** for more details on our digital utility roadmap.

3.4.3 Customer power quality

We manage the majority power quality issues on reactive basis. When customers have identified issues, we immediately respond to check the validity of the issues and ensure that there are no unsafe situations.

In terms of monitoring low voltage issues on our network, the number of issues identified is generally less than 5 per annum. These are addressed immediately or at short notice. The low number is generally due to our connection processes that also include integration with our design and network planning sections.

We understand that future requirements on new load characteristics mean that we will need to manage our LV networks differently. We are actively developing network models of both HV and LV distribution to ensure adequate planning into the future. Also integral to our management processes is accessing additional power quality data through meters installed at the distribution transformer level and at the consumer premises. This will allow us to implement more proactive voltage management processes. Our roadmap for this development is provided in **section 6.2.3.**

3.4.4 Other customer services

There are a number of other customer services identified for development of re-engineered processes and development of customer service KPI's. Work on these will continue over the next 12-18 months. These services include:

- Vegetation Management;
- Private Service Line Management and Land Access;
- Service Requests i.e. requests for close approach (to live network assets), service line isolations, high load road escorts, underground records and electrical installation services (including metering).

3.5 Draft Customer Reliability Service Levels

Our customers' experience in dealing with us and the service levels they receive from our network and related services are key elements in how we operate our business. We remain focussed on ensuring that our network remains reliable and that when our customers contact us, we respond in a timely and professional manner to resolve their queries.

The service levels for our customers have traditionally been the traditional indicators of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These measures are asset-centric and do not give a give a true reflection of customer group or individual performance.

This year we are revising how we monitor customer experience by adding additional performance measures for customer groupings based on where they live or do business rather than how the network assets are configured. We will also align our traditional Security of Supply Standard with these targets. The proposed customer supply groups are shown below alongside draft outage and reliability targets:

Table 9 - Draft customer reliability targets

Customer Supply group	Average annual interruption duration for group (min)	Average annual number of interruptions for group	Max planned interruptions per year per customer	Max unplanned interruptions per customer	Max annual number of recloses per customer	Feeder interruption duration index (min/fdr/yr)
Business Hub	15	0.33	2	2	0	60
Urban	15	0.5	2	3	0	180
Township	23	1	4	4	0	300
Rural A	180	2	4	5	16	600
Rural B	300	3	4	6	20	800
Rural C	450	3	4	7	24	1080
Special	default as per geographical location or agreed with customers					

We will consult with our customers during FY24 to refine these draft service levels. Preliminary analysis against these service levels shows that a number of customers are receiving lower service, which is not apparent in the higher level SAIDI and SAIFI metrics due to the effect of averaging.

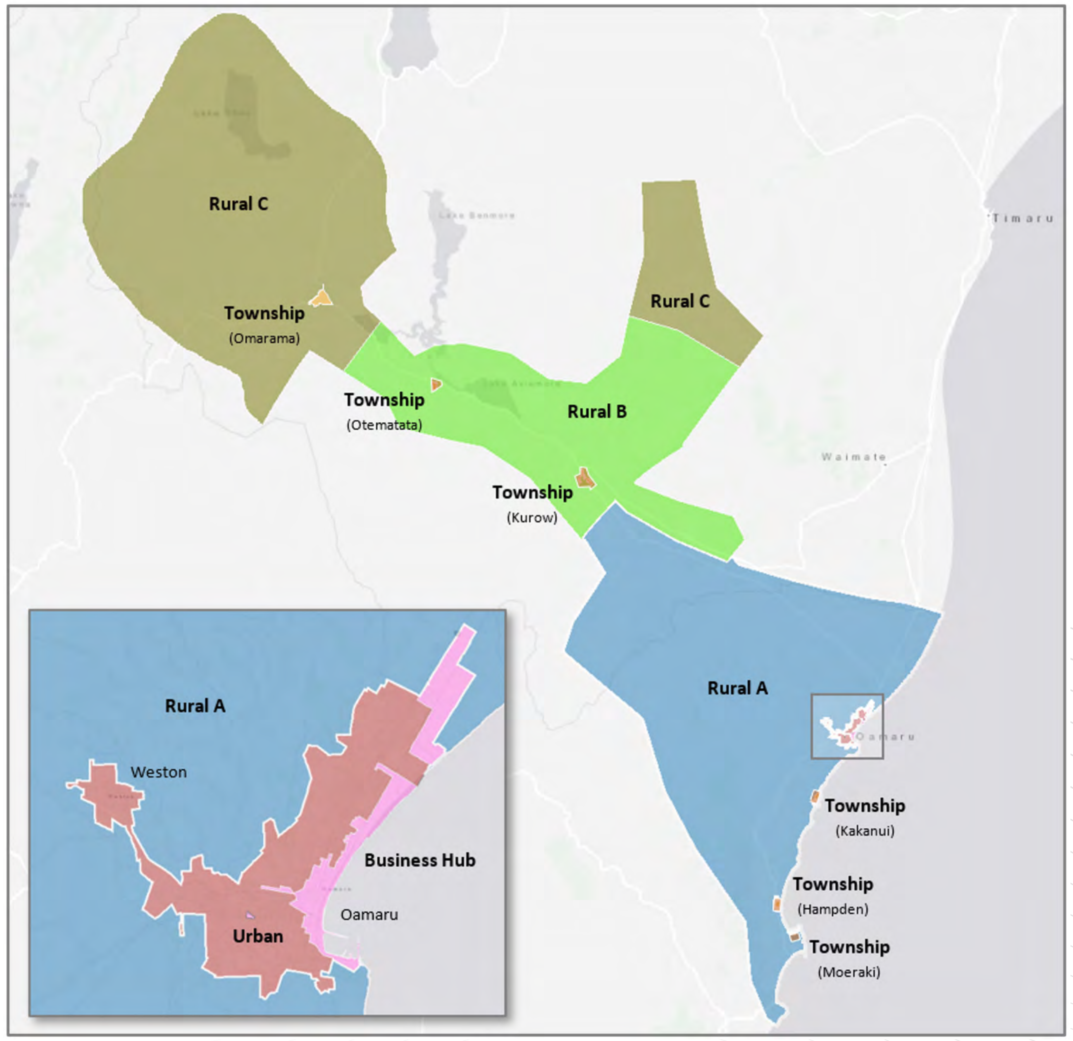


Figure 6 – Preliminary customer reliability results groups

3.5.1 Service level: Network reliability

Reliability of our network is of high importance to us and to our customers. Our customer surveys have revealed that the service attributes most highly valued are "*keeping the power on*" and "*getting the power back on if it goes off*".

3.5.1.1 Objectives

One of our most important corporate objectives is to *"operate a reliable and efficient distribution network"*. Reliability of supply is an important consideration for our customers, especially as the economy decarbonises and electricity becomes more important to both business and domestic users. We aim to strike a balance between good reliability and the cost to our customers of supplying this service.

At a network level, our investment plans associated with maintenance, replacement and development of the network are aimed at ensuring that network reliability does not deteriorate over time. We will ensure that we utilise modern network design techniques and equipment to enhance reliability for our customers where this is cost effective. Specific investment in improved reliability will be driven from performance against targets associated with customer reliability service levels as discussed in section 3.5.

3.5.1.2 Methods

We will meet our reliability objectives by

- designing and constructing new network assets to meet modern reliability standards, considering both the prevailing and any changing environmental conditions
- applying new technology where it can efficiently improve our reliability and customer service outcomes
- monitoring the condition of our network assets using modern techniques to ensure that risks to reliability and safety are discovered
- proactively managing vegetation related issues around our assets
- prioritising and rectifying defects in a timely manner, keeping in mind that minor defects can develop into more serious issues over time
- optimising the use of automated and remotely controlled devices such as reclosers, sectionalisers, and tie-switches to reduce the impact of outages where it is efficient
- monitoring and analysing faults data to identify emerging trends and how to deal with them
- coordinating planned (and where possible, unplanned) work within a geographical area to minimise the impact of planned outages
- examining network performance after major events such as snowstorms to gain insight into Asset Management changes that may improve performance.

3.5.1.3 Measures and targets

In order to ensure that our customers receive an appropriate level of service we need to set performance targets and monitor our activity against those targets and adjust it where there is a signal to change. We use standardised measures to track network performance based on the average number of outages that a customer will experience (SAIFI) and the average total time of outages that they will experience (SAIDI). These measures allow us to monitor our performance from year to year, and against other EDBs.

For compliance reporting, SAIDI and SAIFI are normalised by applying compliance rules to adjust the measures under certain defined circumstances. For most of this chapter however, analysis is presented as either Raw SAIDI or Raw SAIFI which means they have not been normalised. We have used this approach for the analysis and improvement targets because raw values give a true view of the impact that is felt by customers from supply outages on the NWL network.

The targets for SAIDI and SAIFI, as published in our Statement of Corporate Intent, are shown in Table 10 below.

Table 10 - SAIDI and SAIFI targets

Network Non-Financial Performance Measures	2023-24	2024-25	2025-26
Unplanned SAIDI minutes	55	55	55
Planned SAIDI minutes	105	105	105
Total SAIDI minutes	160	160	160
Unplanned SAIFI	1.3	1.3	1.3
Planned SAIFI	0.5	0.5	0.5
Total SAIFI	1.8	1.8	1.8

While keeping safety paramount, we are committed to restoring power to our customers as soon as possible should an unplanned outage occur.

3.5.1.4 Network performance

Our historical SAIDI and SAIFI performance data is shown below in the figures below. The performance levels shown exclude the impact of Transpower outages.

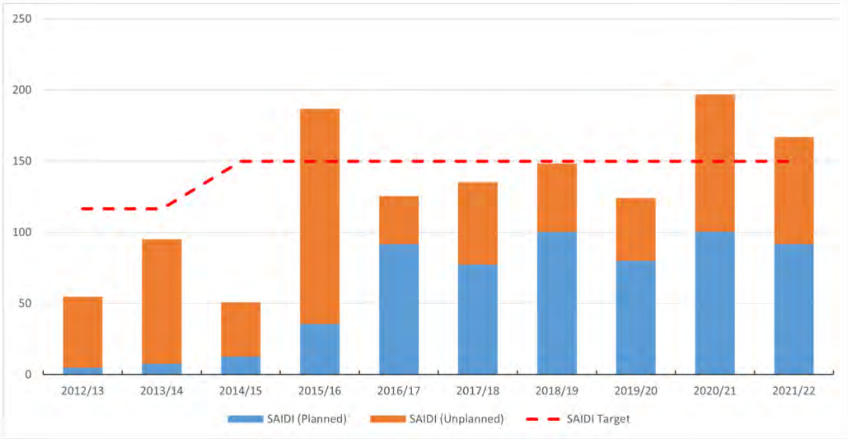


Figure 7 - Historical SAIDI performance compared to target

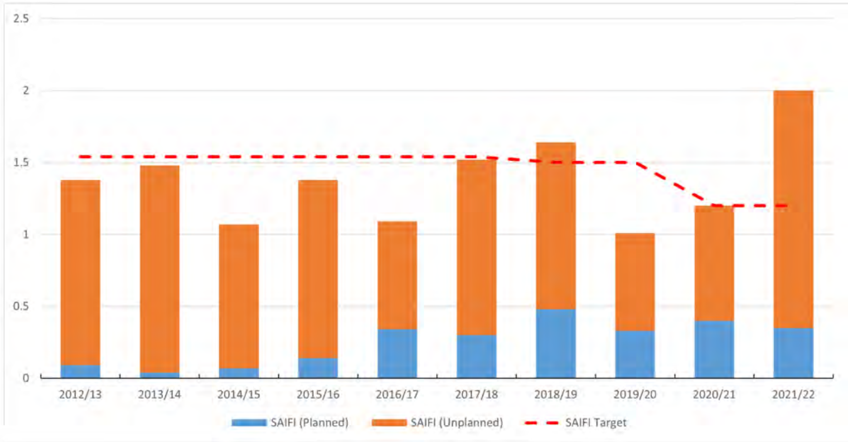


Figure 8 - Historical SAIFI performance compared to target

3.5.1.5 Planned and unplanned outages

The impact of unplanned outages has increased significantly since 2016 due to the implementation of a new risk framework for working with energised equipment.

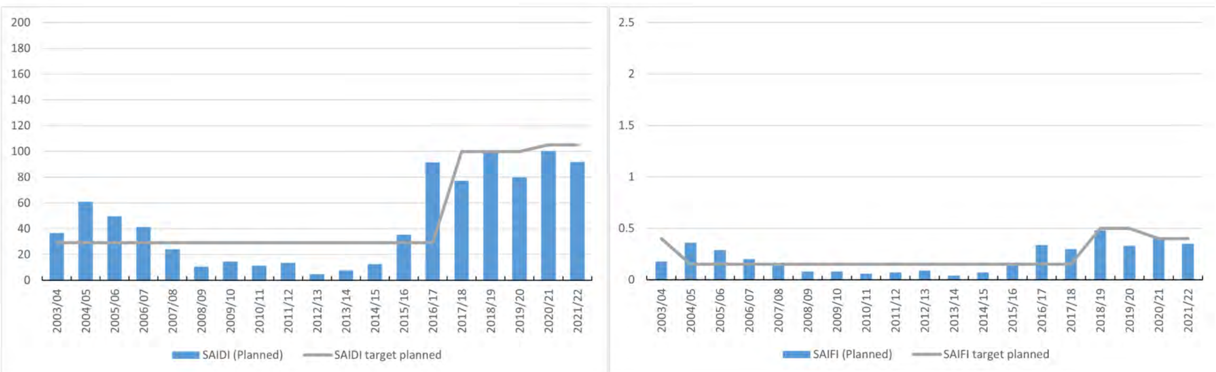


Figure 9 - Historical Planned SAIDI and SAIFI performance compared to target

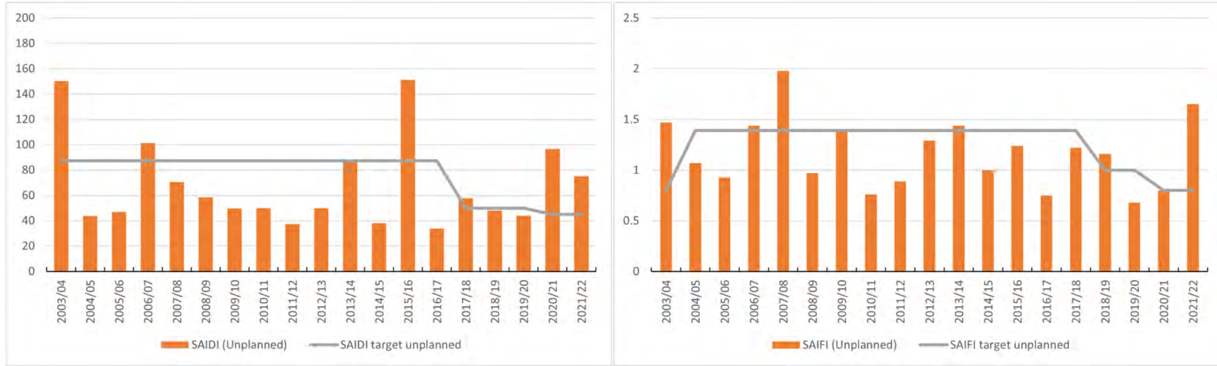


Figure 10 - Historical Unplanned SAIDI and SAIFI performance compared to target

Our performance for unplanned outages is generally consistent except when we have events that affect the sub-transmission system, any of which impacts a large number of customers.

We have projects planned in the next two years to improve the performance of two of our main sub-transmission networks (See **section 6.8.2** for further details). The impact of these projects will be seen after 2025.

We also monitor the service levels experienced by individual customers compared with our service level targets. This analysis shows that fewer than 0.8% of our customers experienced performance that was lower than our delivery targets in the 2021/22 operational year.

We analyse these performance figures to look for evolving trends that may indicate something like a change in operational practice or a targeted replacement programme is required to address the performance. Analysis of the unplanned outages for the previous year shows that there are no particular trends that require significant changes in Network operations. Also refer **section 4.1.7**.

3.5.1.6 Comparison with other New Zealand Networks

We compare our network performance against other EDBs throughout New Zealand in order to show how the service level that we provide for our customers sits against other networks. The source for this is performance data published by the Commerce Commission on their website[5], which is taken from the information disclosures provided annually by EDBs to the Commission.

One of the common comparative reliability metrics associated is the number of unplanned interruptions (faults) that occur per 100km of circuit length. This provides a normalising factor between networks of different sizes, and the comparison of NWL against all other EDBs based on a three-year average of data is shown in Figure 11 below:

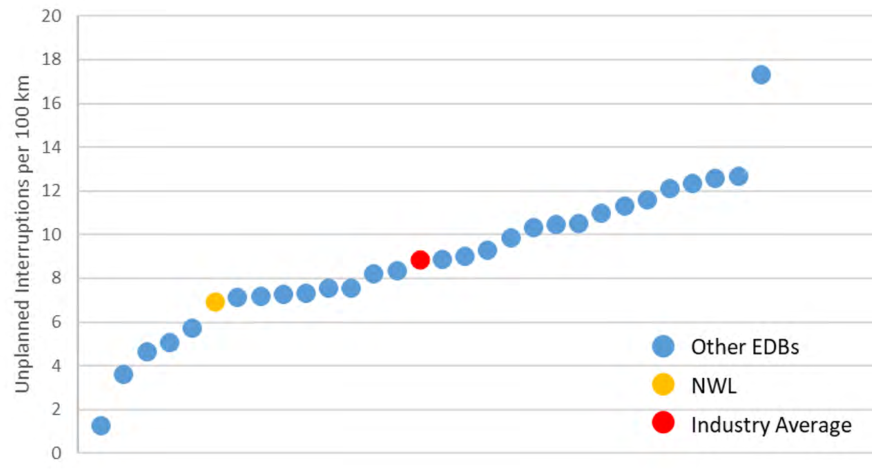


Figure 11 – Comparison of 3-year average of NWL unplanned interruptions per 100km against industry

The 3-year average of unplanned interruptions per km on our network sits 22% below the average level for all EDB's in New Zealand.

[5] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data

We monitor our performance against a group of EDBs that we consider to be our peers. These EDBs are our immediate neighbours and other South Island networks that have similar operational environments, customer bases and network characteristics. These peers are listed in the table below:

Table 11 - Peer EDBs for the purposes of performance comparison

EDB	Region
Alpine Energy	South Canterbury
Network Tasman	Tasman region
Buller Electricity	Buller region
EA Networks	Mid Canterbury
Mainpower	North Canterbury
Marlborough Lines	Marlborough
OtagoNet Joint Venture	Otago
Westpower	West Coast

The comparison of our unplanned interruption performance per 100km of circuit length to that of our peer EDBs, averaged over the last three years is shown in Figure 12 below:

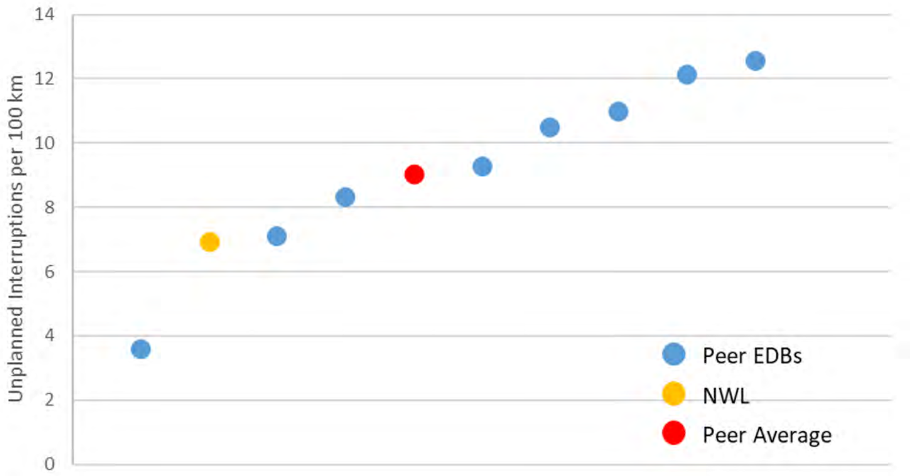


Figure 12 - Comparison of 3-year average NWL unplanned interruptions per 100km of circuit against peer EDBs

This shows that our performance for the incidence of unplanned outages 24% below the average for our peer group.

When we consider the SAIDI and SAIFI figures for the peer group as shown in the figures below, it is clear that both our 3-year average unplanned and total outage (planned plus unplanned) performance is very favourable compared with our peers. The particularly low SAIDI figure indicates that the combination of network design to restore load quickly, and rapid fault response, are providing our connected customers with a good level of service. The consistency of our overall SAIDI and SAIFI over the last 5 years was shown at the start of this section, and we believe that the combination of steady performance combined with our position relative to our peer group demonstrates that we are providing our connected customers with a reliable service. We have met our target of better performance by being better than the peer group average.

In the case of unplanned SAIDI minutes (the outage time that an average customer will experience per annum), we are the best performing of our peers, with our three-year average at approximately 47% of the peer group average.

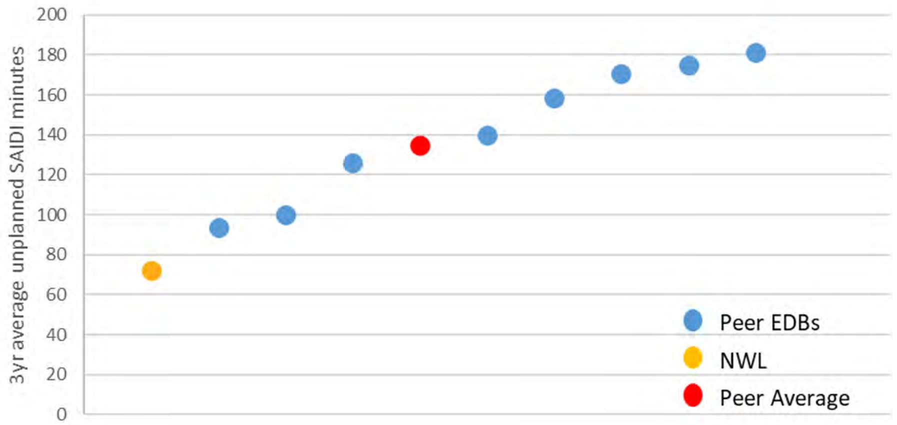


Figure 13 - Comparison of 3-year average unplanned SAIDI against peer EDBs

For total SAIDI we are more than 45% lower than our peer group average.

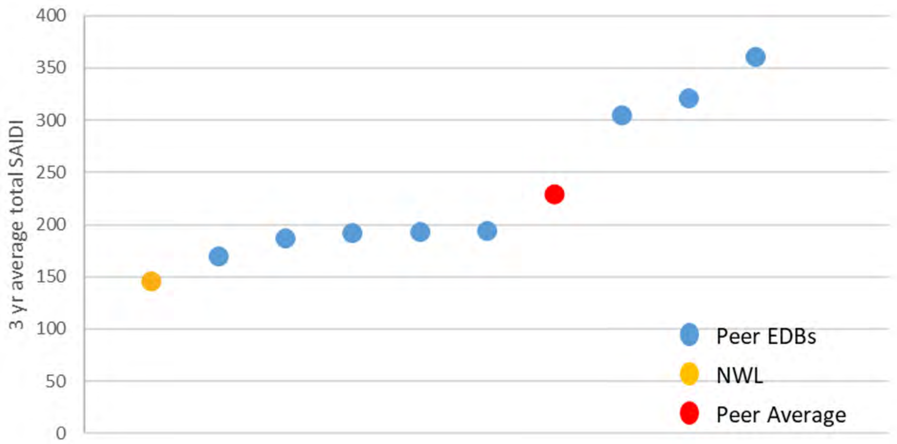


Figure 14 - Comparison of 3-year average total normalised SAIDI against peer EDBs

For unplanned SAIFI (the number of outages an average customer will experience in one year) the 3yr rolling average is also more than 20% lower than the average of our peer group. Our customers experience the third lowest unplanned interruptions of our peer group.

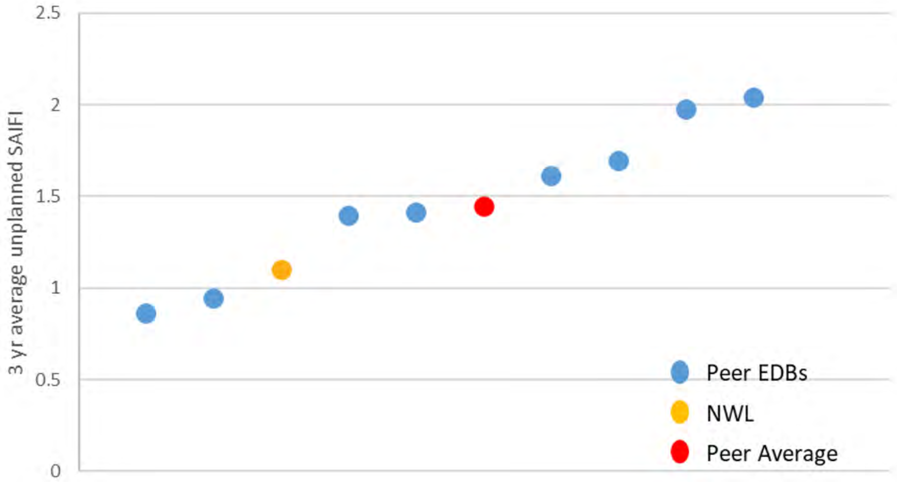


Figure 15 - Comparison of 3-year average unplanned SAIFI against peer EDBs

Total SAIFI includes the effect of planned outages on our customers. Again, our customers experience the third to lowest outage impact in our peer group, with our 3-year rolling SAIFI sitting 22% below the group average.

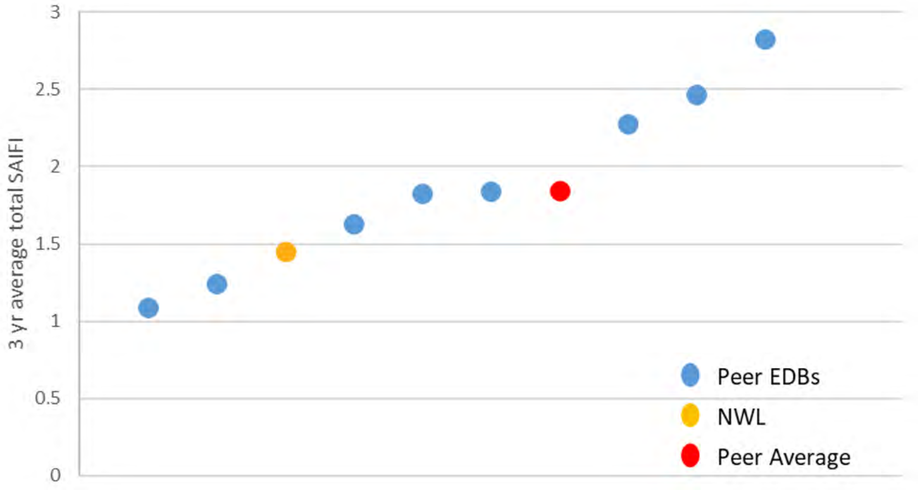


Figure 16 - Comparison of 3-year average total normalised SAIFI against peer EDBs

We believe that the data shown in the figures above can give our stakeholders comfort that we are performing well compared with our peers and delivering an appropriate level of service to them.

3.5.2 Analysis of Issues causing unplanned outages

We analyse causes of unplanned outages and their impact on our customers so we can continuously improve our asset management practises to minimise future impacts. What we have found recently is that while we are able to reduce the average fault per 100km to levels below the industry norm, we are not achieving the SAIDI/SAIFI targets we want for our customers. This is due to the impact that individual faults are having on the numbers of our customers, i.e. we are having a small number of faults causing outages for large numbers of customers, and also comparatively long time taken to get our customers service restored. To this end we have focused on developing more customer centric reliability performance measures and as a result are now identifying specific projects to address service gaps. Refer section 3.5.

3.5.3 Service level: Economic efficiency

As well as delivering supply reliably, there is a need to ensure customers are supplied in an economically efficient and cost-effective manner. We consider that one of the best ways to verify that we are economically efficient is to compare our performance to that of similar EDBs. We therefore benchmark several measures against other network companies to understand whether our asset investment strategies are delivering efficient outcomes for the benefit of our electricity customers in the region.

3.5.3.1 Objectives

It is important to us that we provide a safe and reliable electricity supply that is economically efficient, and that we do this in a sustainable manner. This requires us to make sure that the service we provide to our customers is economically efficient.

3.5.3.2 Methods

To ensure that our economic efficiency targets are achieved we

- work with our customers to ensure that their supplies are optimised to their requirements
- consider the impact of losses when evaluating options for network upgrades and renewals
- optimise loading between our GXPs to improve the efficiency of energy transmission to customers
- actively manage capacity and asset utilisation, and balance equipment loadings where an under or overuse becomes apparent
- continually work to improve our works delivery model and processes
- investigate new technology options where they can provide improved performance and offer solutions from others where these are more economic.

3.5.3.3 Measures and performance

The economic efficiency measures that we apply are:

- Operational expenditure per connection point
- Operational expenditure per km of network

3.5.3.3.1 Total operational expenditure per connection point – measure and targets

This measure provides an understanding as to whether operating expenditures are appropriate given the operating parameters of our company. Adequate levels of operational expenditure per connection point are required to ensure sufficient maintenance is performed to maintain overall system reliability.

We compare our forecast operational expenditure budgets against peer EDBs, including an allowance for inflation. This measure includes all the operational costs involved in running the network, including support functions such as IT, finance, and health and safety. Tracking this measure links our asset management processes to customer and stakeholder preferences for supply reliability.

3.5.3.3.2 Total operational expenditure – performance

The measures associated with operational expenditure provide a view of whether the network operating expenditures (preventative maintenance, corrective maintenance, reactive maintenance, and vegetation management and business support functions) are appropriate for our network.

The figure below shows a comparison between the three-year average of our total operational expenditure (OPEX) per connection point and that of all other EDBs in New Zealand.

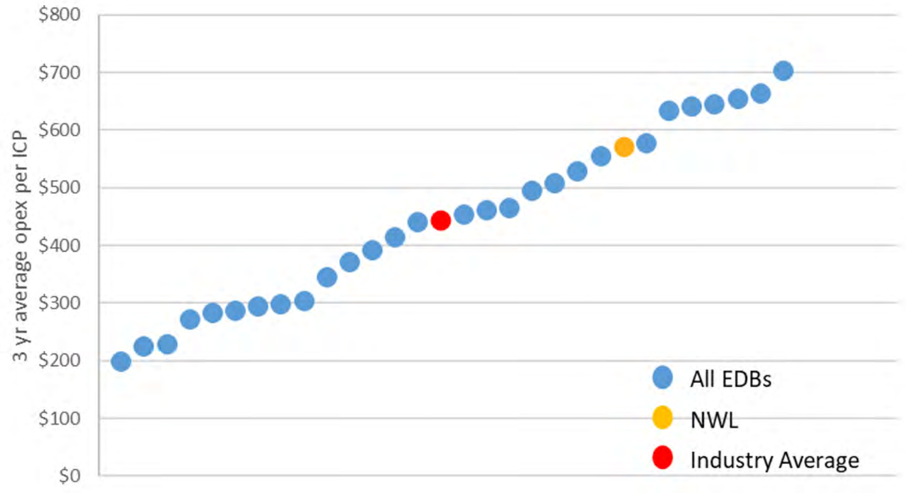


Figure 17 - 3-year average operational expenditure per connection point performance compared to all EDBs

In the context of the entire industry our operational costs are above average. This comparison includes large EDBs with densely populated networks, which skews the cost/ICP profile due to scale. We believe that it is more appropriate to compare our operating costs to the networks in our peer group. The following graphs show the operational cost comparisons between our peer group of EDBs for the average of the last three years.

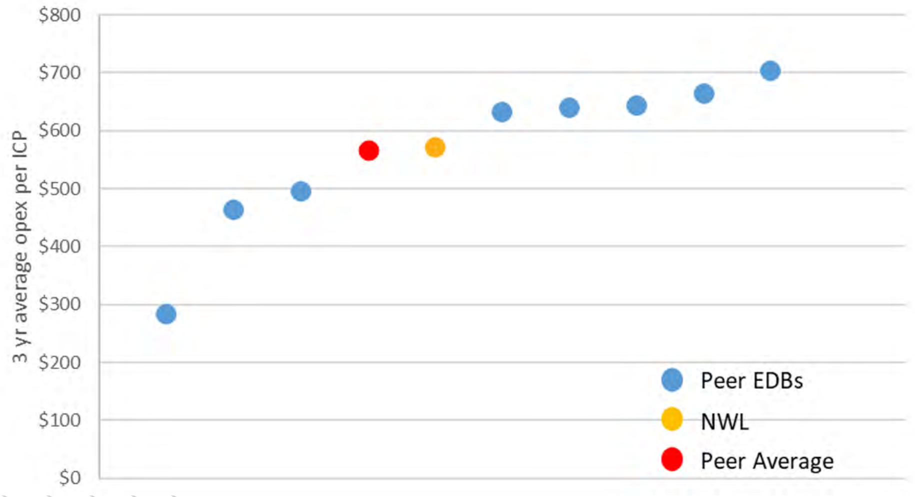


Figure 18 - Comparison of 3-year average total operational expenditure per ICP against peer EDBs

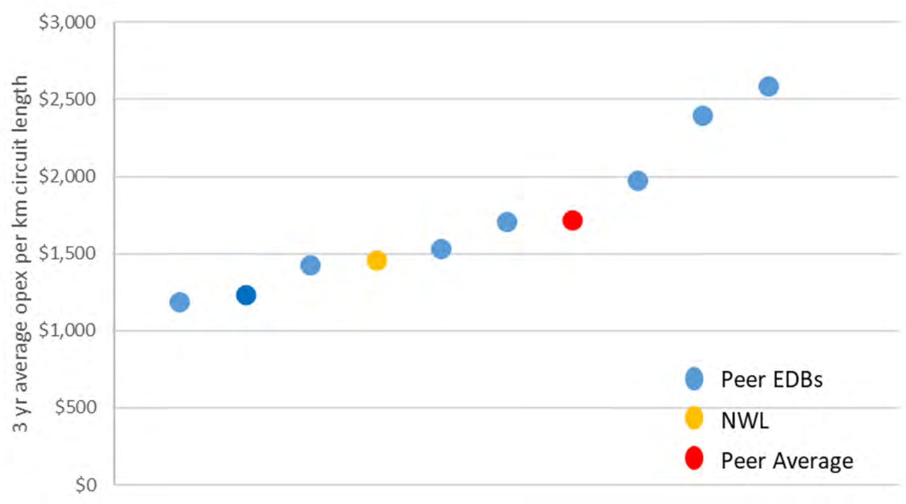


Figure 19 - Comparison of 3-year average network operational expenditure per kilometre of circuit length against peer EDBs

Our 3-year rolling total Opex/ICP sits almost exactly on our peer group average. Given our excellent comparative reliability performance (shown in **section 3.3**) we believe that we are providing a very cost-effective service to our customers, as shown by our OPEX per ICP being below our peer group average, while our SAIDI and SAIFI performance is among the best in our peer group.

Refering to Figure 19, our 3-year rolling average for operational costs per kilometre of circuit length is 15% below the average for our peer group of EDBs.

The combination of reliability and the operational expense measures show that we are successfully and efficiently delivering our electricity network services.

We will work on keeping our operational costs at an appropriate and efficient level by

- ensuring proactive maintenance and repairs are efficiently completed to ensure fewer faults and asset failures occur
- evaluating and making 'replace versus repair' decisions before undertaking large corrective maintenance projects
- considering ongoing lifecycle operational costs in the selection of equipment and systems and selecting equipment that balances operational and capital expense.

Approach to Asset Management

04

Approach to Asset Management

This chapter outlines the approach that we take to managing our Network assets. It provides an outline of the key parts of the planning and the delivery areas of this discipline. This chapter is structured as follows:

Asset management process: Provides an overview of how we view Asset Management as a process and provides detail of how key elements fit the process.

Asset lifecycle management: Describes how we approach the different aspects of the lifecycle of our assets, including initial investment, ongoing maintenance, and refurbishment, and how we make decisions on asset investment.

Risk management framework: Describes how we apply Risk Management to our business, especially around the treatment of assets.

Public Safety Management System, high impact low probability events and emergency response policies and contingency plans: These sections outline processes that we use to manage keeping our network safe for the public, and how we manage our preparedness for major events.

Asset management maturity: This section reflects on how mature we believe our asset management processes are, specifically using the Commerce Commission's AMMAT system for analysis.

Improvement initiatives/continuous improvement: This section outlines the ways in which we are working to improve our asset management capability.

4.1 Asset Management Process

The process that we apply to planning our Asset Management is illustrated in Figure 20 below:

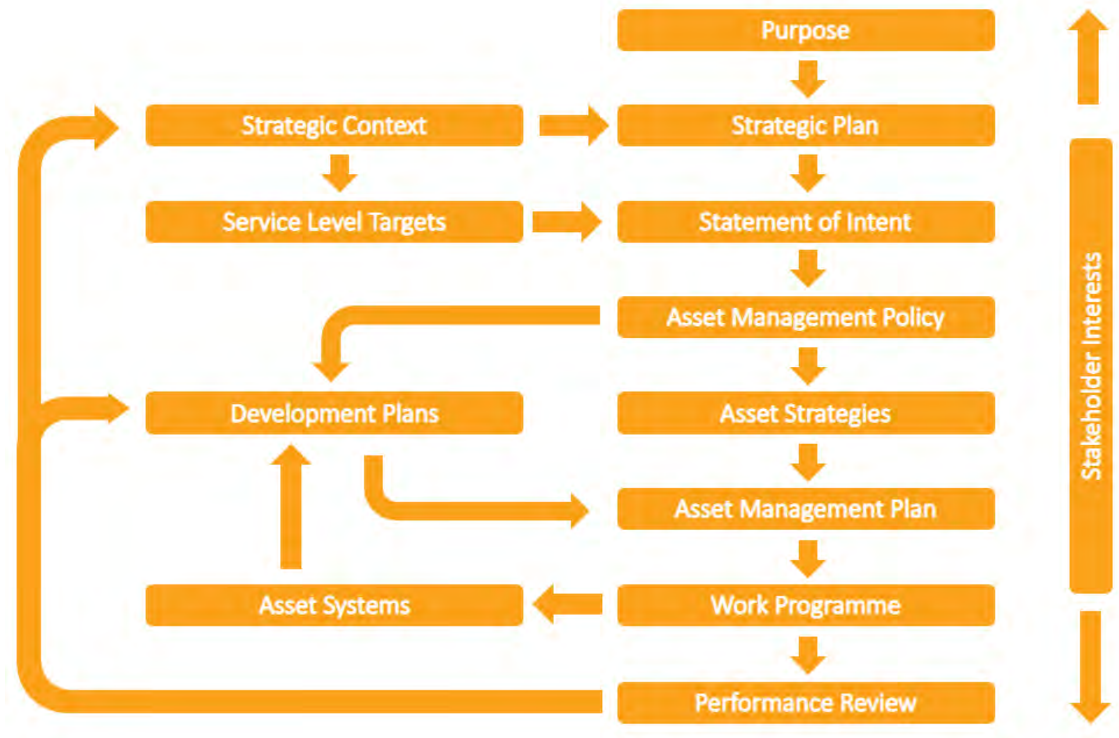


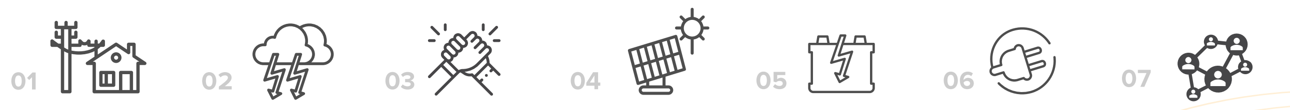
Figure 20 - NWL asset management process

The planning process should be viewed as a continuous cycle rather than a hierarchy of documents. Details of some of the key components of this process are described on the following pages.

4.1.1 Company strategic plan

In 2022 we developed and launched an updated strategic plan that will ensure alignment of the entire business to deliver on our vision of "Powering a vibrant Waitaki" and propel our mission for the ongoing future of our business by "Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers".

4.1.1.1 Our strategic context



01 Traditional distribution infrastructure and assets will continue to remain important, integrated with emerging technologies

02 Environmental and societal changes will shift preferences and expectations

03 Customers will demand more flexibility and choice, seeking improved experiences with greater value and utility on top of reliability of service

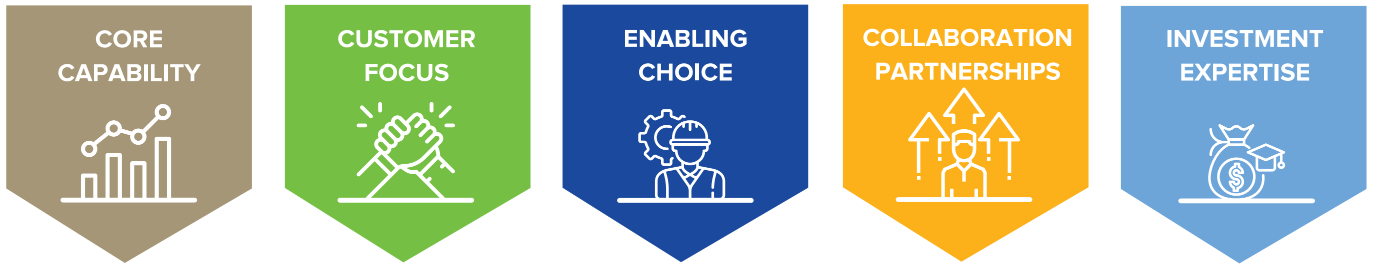
04 Renewable energy technologies will become prevalent, becoming more available and affordable

05 Mass energy storage will become cheaper to purchase, build and manage

06 Electrification will continue to see demand grow

07 Energy services will evolve away from unidirectional flow and into multi-directional flows

4.1.1.2 Our strategic priorities



We excel in what we do, providing a safe, reliable and valuable service for our customers and great place to work for our people

We are effective in our impact on our environment and enabling a sustainable future for the community for which we serve

We provide excellent customer service and community engagement and are valued by the customer, the region and our shareholder

Our strong 'can do' culture underpins our capability to deliver what our customers want

We are a trusted advisor and supplier of innovative energy solutions for our customers, to enable their full participation in the new energy future and a low carbon economy

We have a range of profitable services on offer and are the service provider of choice

We develop the culture, skills and expertise that we leverage to partner with others to create value

We engage and collaborate with key partners to enhance our business and capability, to access expertise and scale, to improve efficiency and service delivery

We will be excellent in our selection, management, and delivery of network and non-network investments aligned to our core competencies

We will enhance our financial performance by making smart investments to deliver shareholder value

4.1.2 Asset management policy

The purpose of our Asset Management Policy is to ensure that our asset management activities occur within a structured and systematic framework. This framework provides a focus on delivering a safe, reliable, secure, resilient, and cost-effective supply of electricity that meets the performance expectations of our customers, while complying with all relevant New Zealand laws, regulations, and codes of practice. Specifically, our Asset Management Policy states:

It is NWL's policy that the electricity network is designed, constructed, operated, and maintained in a safe and efficient manner aligned to good industry practice, and follows the following principles:

1. Safety is the highest priority. We are committed to instilling a strong safety culture and capability throughout the company. We strive for zero harm to employees, contractors, and members of the public.
2. We will plan our activities to sustainably meet the price and service quality expectations of our customers. We will do this by engaging with our customers and stakeholders for consideration with other strategic, economic, and regulatory drivers.
3. Our investments will be clearly aligned with delivering our service level targets, effectively managing risk and optimising lifecycle cost.
4. We will consider non-network and demand-side solutions, technology, innovation and investment and operational efficiency when we seek to optimise our investment.
5. We will continuously improve our Asset Management practices, to align with nationally and internationally recognised asset management standards.
6. We will develop and retain talented, competent and motivated people to maintain and improve our asset management capability.
7. We will consult and manage our asset management practices in accordance with obligations related to the Treaty of Waitangi, "Te Tiriti o Waitangi".
8. We will include emerging factors such as Decarbonisation, Climate Change, Sustainability, and Social Responsibility in our Asset Management activities.
9. We will comply with all environmental, security and other relevant statutory and regulatory requirements.

4.1.3 Asset management strategy

Our Asset Management strategy is to ensure that our asset management practices continue to deliver agreed service levels as set out in this AMP at minimum long-term cost.

Our Asset Management strategy aligns with our Asset Management Policy and corporate objectives and encompasses the components listed below.

4.1.3.1 Asset configuration

The following strategies are applied to our consideration of asset configuration:

- We will take a long-term view of asset requirements, noting that customers ultimately benefit from well planned investments.
- When building new assets or rebuilding existing ones, we will ensure that the capability to meet future needs is built in: i.e. purchase sufficient land to enable dual transformer (where appropriate) substations to be built.
- We will consider using portable or semi-portable generators at distribution substations to help meet customer reliability levels during planned and unplanned outages. To enable this, when installing new or upgrading existing distribution boxes, consideration will be given to installing generator connection plugs to enable quick and easy connection of portable generators.

4.1.3.2 Resourcing

The key strategies applied to resourcing for our company are:

- We will identify the required skill sets needed for effective asset management and have a well-developed recruitment and training plan in place.
- We will ensure that our contracting business has a well-developed recruitment/training plan – an ageing workforce means that we need to prepare workers to deliver on the strategy during the planning period.
- We will continue to utilise external contractors to maintain our specialist systems such as communications and SCADA networks.
- We will continue to maintain our engineering skill set through the hiring of qualified engineers and supporting the growth of trained engineers by providing scholarships for local engineering students.
- As technology and systems advance, we will actively identify gaps in skillsets so we use the best tools and train our staff or recruit to fill those deficiencies.
- We will continue to engage suitable consultants for specialist work including civil design, protection, and regulatory advice.

Finding staff to fill technical roles is a particular issue for our sector. Skilled immigrants are one of the pools of talent that all EDB's draw upon, and with ongoing difficulties in immigration, combined with an ageing workforce, we risk difficulty in filling open positions. This has led to a greater focus on the development of trainees and the identification of components of work where less skilled staff can be used without compromising quality or safety.

4.1.3.3 Materials

We recognise that decisions made around material selection for construction projects can have long term implications on capital and operational expenditure. We apply the following principles to purchasing decisions:

We will use only materials and equipment approved by our internal policies and standards, or by specific design where necessary.

- In assessing offers to supply materials or equipment, we shall consider the total life cycle costs of the offer.
- When bringing new equipment types onto the network we will follow a rigorous procurement process which will examine the risks associated with safety, longevity, maintainability, and operability of the equipment.

Worldwide logistic issues have an impact on almost all of our suppliers to some extent or another. International freight disruptions have affected the price and availability of raw and finished materials, leading to some uncertainty with supply arrangements. We anticipate that equipment will only be available on longer lead times and will factor this in when purchasing major equipment for projects in the first few years of the works programme.

4.1.3.4 Delivery of works programme

Where practical our engineering staff commence design for major projects in the financial years before the works programme that the project is scheduled for. Budgets are developed to provide funds to do this prework where possible. This smooths out the planning and delivery process and allows for consents, long lead time procurement and resourcing scheduling.

This also provides opportunities to pre-order long lead-time material items so they can arrive earlier in the financial year, providing more flexibility for works delivery and resulting in a smoother flow of work. A project may be moved forwards or backwards in the plan to take advantage of an opportunity, provided that this does not introduce undue risk.

Progress against the works programme is monitored by the management team throughout the year, with attention paid to the resourcing and prioritisation of work. The timing of a job may be brought forward or deferred depending on the priority. An example of this is when low priority maintenance such as painting an asset may be moved back in the works programme to free up resource to carry out safety related work which may not have been in the original works plan but has arisen through routine inspections.

4.1.3.5 Performance reporting for asset management

We believe that the asset management of our network should be implemented in an open and transparent manner. The key formal reporting mechanisms that we employ are shown below:

Reporting line	Reporting mechanisms and content
The Company to customers and stakeholders	The company website includes the AMP, Company Annual Report, and other disclosure documents. Company annual report includes Chairman and Chief Executive's statements and audited accounts. Annual information disclosure.
The Board to the Trust	Quarterly presentation includes financial and operational performance.
Chief Executive to the Board	Monthly board report includes network performance updates, risk management activities, and progress on works programme delivery. Out-of-cycle reporting on significant developments.
Management Team to Chief Executive and the Board	Annual reports on budget and major projects. Monthly reports include network performance and progress against budget. Individual reports on major projects. Daily updates on areas of concern.

Table 12 - Key asset management reporting mechanisms

4.1.4 The Asset Management Plan

This Asset Management Plan (AMP) is intended to give stakeholders a window into our asset management practices, and to communicate our plans for the next 10 years of operation and development of the network.

In particular, the objectives of this AMP are to:

- Link the asset management processes to customer and stakeholder preferences for prices, supply reliability, and public safety.
- Demonstrate that all asset lifecycle activities, plans, and associated costs are systematically planned with a long-term view towards minimising lifecycle costs, which promotes productive efficiency.
- Demonstrate that physical, commercial, and regulatory risks are correctly managed throughout the life of our assets.

4.2 Asset Lifecycle Management

An overview of the typical lifecycle of a network asset is shown in Figure 21:

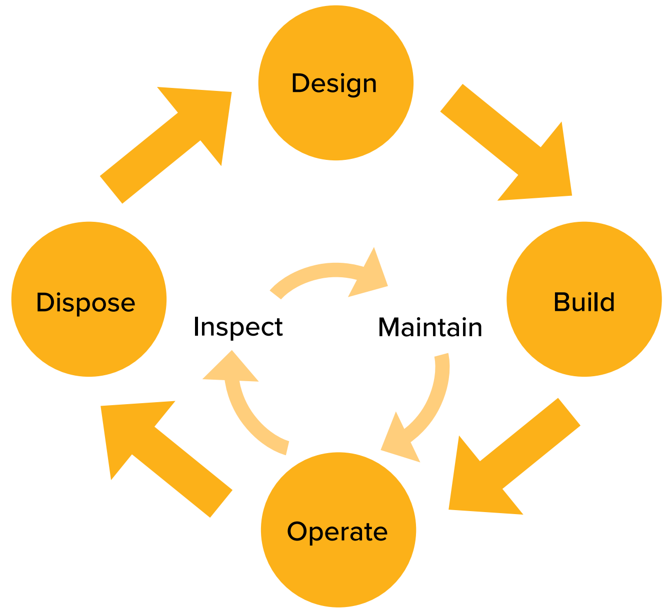


Figure 21 - Typical network asset lifecycle

4.2.1 Design and procurement

The design and procurement activities are where we begin to influence the service life of our assets. By following good design practice and standards and working with reputable suppliers we control the quality of assets entering service on the network.

We follow a rigorous change management process to ensure that new equipment can be safely installed, operated, and maintained on the network. This process also identifies any special tools or techniques that may be needed for the installation and operation of any new type of asset, and helps provide our staff with the training necessary to safely install, operate and maintain the assets.

4.2.2 Installation and commissioning

Using correct techniques and equipment for installation and commissioning ensures that new assets are installed as per the manufacturer's intentions and are operated within design tolerances. Examples of this are following specific handling methods for lifting concrete poles, and having trained staff use the correct tooling for installation of cable terminations.

4.2.3 Preventative Maintenance and Inspections

During their operational life assets are regularly inspected to identify any defects. Inspection intervals are determined according to the type and criticality of the asset to make sure that it still meets the required levels of service, and to meet legislative requirements for operation of the network.

Inspections include visual inspections such as a walk around a substation fence, as well as more in-depth condition-monitoring such as the thermal inspection of a roadside distribution transformer, or X-ray and seismic technology for inspections of a wooden power pole. Inspections can also include non-intrusive testing such as earth resistance, oil sampling and partial discharge tests. Periodic inspections and tests are usually scheduled at suitable time-based intervals based on the criticality or consequence of failure of the asset. The frequency of inspections is affected by asset type (high value assets are more closely monitored), physical location (highly public occupancy or fire risk areas) or electrical location within the system (if more customers lose supply upon failure).

An important aspect of our inspection regimes is the safety of our assets for our workers and the public. Safety risk for an asset can be affected by external factors such as public activities in the road or public spaces where our assets are, or the presence of vegetation near our overhead lines. To mitigate these factors, our inspections consider public safety , based on where the asset is, and what activities or external risks are present in the environment.

A specific form of public safety risk management is the control of vegetation around our overhead lines. Trees and other vegetation can pose a significant risk to public safety through fires and electric shock hazard, as well as the reliability of our network. We maintain a vegetation management team of specialist Utility Arborists within our Contracting team and engage with the public in multiple ways to inform and educate them of the risks around managing their trees. Our vegetation management team complete scheduled patrols of our overhead network to manage risk to the safe and reliable operation of the network. They work with tree owners to resolve problems within the Electricity (Hazards from Trees) Regulations 2003, and adhere to good practice.

Preventative maintenance is carried out based on the results of condition assessments and at scheduled intervals in order to keep the equipment in good condition. Preventative maintenance includes activities such as greasing and checking the contacts on an air brake switch or maintaining the on-load tap changer on a power transformer. These activities can be scheduled based on time cycles (e.g., 3 yearly) or on operational activity (e.g., after three high current faults).

We are also trialling real time monitoring on some assets in order to optimise our response to conditions such as overloading, and in some cases to potentially discover defect conditions much earlier than we presently can.

4.2.4 Asset defects

Assets that do not meet a required service level are recorded in our defect management database. The defect process includes a risk assessment to identify potential risks, including the safety of the public and our workers, and the possible effects on the network. Defects which have a potential risk of causing serious harm to members of the public, employees, or property; or which could have a significant impact on the reliability of the network, are treated with high priority and must be resolved rapidly.

Information to trigger renewals or maintenance can also come from analysis of fault reports, from observations by our staff or members of the public, or from wider industry advice of an issue with a particular asset type.

A defect may be due to the failure of an asset to meet a required level of service such as electrical capacity (e.g., an overload on a transformer), structural capacity (degradation of a power pole means it can no longer safely support conductors), or operational (the asset cannot be supported due to age and lack of spare parts). The outcome of the defect can range from a gradual reduction in useable life or capacity, through to catastrophic failure.

4.2.5 Repair, renewal, or replacement decisions

When planning remedial work, the risk assessment is reviewed to determine the appropriate intervention strategy. It is important to deal with a defect that has a high safety, environmental or network operational risk attached such as a damaged ground mount transformer, whereas a less urgent intervention can be scheduled for a future date, possibly during a planned shutdown. Occasionally the risk associated with a defect is so low that pre-emptive intervention is not considered economical, and the asset may be left to run to failure with appropriate monitoring.

Intervention can involve repairing an asset in place (return to pre-defect condition or capacity), renewing it on site (improving on pre-defect condition or capacity) or replacing it with a new asset. The age, condition, urgency of the defect and any known issues with that type of asset are all considered in making this decision.

Sometimes a renewal programme will be triggered based on the age and general condition of a group of assets, such as an overhead line of a particular type and age, or a type of switchgear that is known to fail prematurely, rather than specific individual defects. These planned renewals are undertaken to ensure network safety and reliability.

Renewal may also be carried out to ensure that an asset or system will continue to meet its performance requirements, such as capacity or speed of operation.

4.2.6 Standard life expectancy, asset age and health data

Our company has applied standard life expectancy figures across all categories of assets for many years. The values for these life figures are developed from industry-published figures and are used primarily for accounting purposes such as setting depreciation rates. In practice we are seeing that the useful (and safe) life of our assets is generally higher than the standard life, and can be highly dependent on location, treatment, and loading. For this reason, wherever possible we avoid using age as a proxy for condition and base asset decisions on test results or observed data.

Asset Health is primarily based on condition information. The condition information can be further separated into objective (test results) and subjective (visual assessment) data. Where assets lack suitably robust condition data then modelling, using parameters such as type (make and model), location (environmental/pollutants) and age, are used. Where a failure mode trend has been identified, the assets that have features in common with that trend may be replaced at an accelerated rate.

Assets have varying degrees of obtainable data. Where there is evidence supporting a likely state (such as similar or adjacent equipment, or staff knowledge) then we will assess them equivalently. Otherwise, we will take a conservative approach and place the assets in the lower health band for that type of asset.

4.2.7 Investment decision framework

Major investment in the network such as new lines or zone substations are often triggered by the presence of a constraint in the operation of the existing equipment. Before major investment is considered on our network, consideration is given to the following options:

1. Accept the risk

The risk may only exist for a handful of hours per year, or during a very particular set of circumstances, so the decision may be made to accept the risk of the constraint, especially where the cost of remediation is high. This option is not usually implemented permanently and may be used where longer-term solutions cannot meet required timeframes or where the costs of other options significantly outweigh the benefits. The risks of operating in this mode must be quantified and assessed as acceptable to stakeholders.

2. Optimise the network

This option could involve altering the configuration of 11 kV feeders to shift load from a heavily loaded to a lightly loaded feeder or it could involve installing a voltage regulator on a feeder to avoid a conductor upgrade.

Consequences such as increasing system losses or a reduction in security of supply should be included in the cost-benefit analysis.

3. Control customer demand

This option involves NWL acting to reduce customer demand while a constraint is present.

If new load is likely to exceed a constraint limit NWL may choose to impose conditions that allow NWL to control that demand during constraint periods. If the network is upgraded to remove the constraint these conditions may be removed.

Demand that may be controlled includes demand traditionally available for interruption such as water heaters and demand that is specified as controllable in our Security of Supply Standard (e.g., irrigation demand).

4. Non-network solutions

This option may be used to augment parts of our network or in some cases replace them. In some cases, a remote power system (typically a system combining solar and diesel generation with battery storage) may be more cost effective compared with a traditional power line. The comparative lifecycle costs of non-network solutions are examined where there are new lines, capacity upgrades or replacements being considered. There is more detail on our approach to non-network solutions in **Section 6.3 – Our planning approach**.

5. Modify or re-rate existing assets

This option could involve a design review to increase conductor maximum temperatures or using dynamic rating on a line or cable to increase capacity. Cooling fans could be added to a transformer to increase capacity.

6. Install new assets

This involves either building new network or upgrading existing assets.

Customer demand increases are often signalled to us at short notice (in this context, less than 12 months), which may require that options 1 to 3 are used in the short term, followed by a long-term response following detailed analysis of all appropriate options.

For low-cost projects, we use deterministic rules from our design and Security of Supply standards which may result in evaluating only a subset of these options.

All options selected for detailed study are evaluated for cost and benefit (including costs of energy losses and value of lost load where appropriate) and considered for alignment with:

- Our strategic plan (which includes health and safety, environment, and sustainability requirements)
- Statutory requirements (e.g., voltage, power quality limits)
- NWL Security of Supply Standard
- Forecast network capacity requirements
- Customer reliability requirements.

Options are scored across these categories and ranked according to their scores. The option (or options) with the best score is submitted for expenditure approval.

4.2.8 Expenditure approvals

Following on from this initial prioritisation process, a Project Expenditure Approval is prepared for any budgeted individual project over $50,000; any individual project over $250,000 or major unbudgeted project requires a business case which will approved by the Chief Executive (>$250K) or the Board (>$1M).

The business case includes details of:

- The risks and issues that the project is designed to address
- Analysis of the options that have been considered
- Recommendations for solutions
- The rationale for the selected option or options
- Financial analysis of the options, including a risk-based assessment of the cost of lost load, if applicable
- Analysis of performance impacts with respect to SAIDI and SAIFI and any other service level targets
- Any other benefits that will accrue from this project in terms of security, quality, customer/community perception etc.

4.3 Risk Management Framework

Our business faces a wide range of risks. Some of those risks relate specifically to our network assets and the physical environment in which they are located, whilst other risks include more generic risks that all businesses face. Risk management is a fundamental part of good management practice and corporate governance, and effective stewardship of our assets.

Our approach to risk management strengthens our asset management decision making and practices. We apply risk management across all of our business activities, including network planning, policy development, business planning and change management. We adopt a systematic risk management process that is based on the international standard *AS/NZS ISO 31000:2009 – Risk management – Principles and guidelines.*

Figure 22 below illustrates the systematic application of risk management according to the standard:

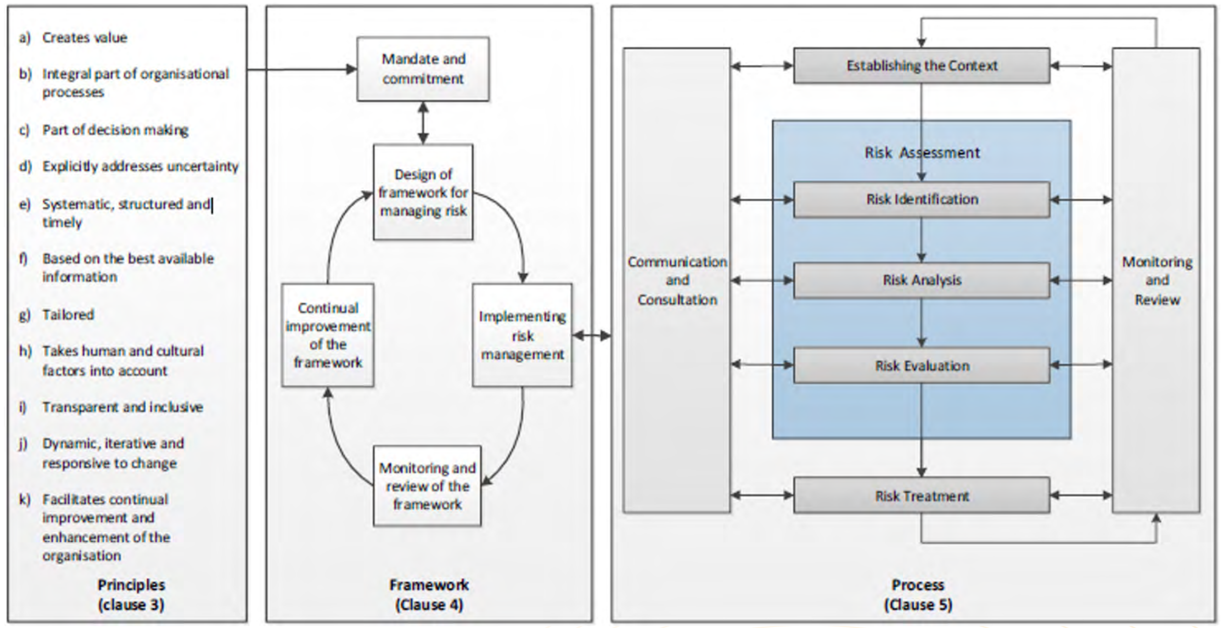


Figure 22 - From ISO31000:2009

Our risk management system consists of the following components:

- Risk management policy
- NWL risk management framework
- Risk management process
- Risk management plans
- Risk registers
- Risk reporting

4.3.1 Risk Management Policy

Our Risk Management Policy is updated regularly and applies to all business operations of Network Waitaki. It presents our risk management objectives, provides guidance for establishing risk appetite and lays out responsibilities of our staff. It is intended to support and drive

- protection of people, the community, our network, the environment, and the business through effective risk management
- a flexible and evolving risk management framework aligned to the *AS/NZS ISO 31000 Risk Management Standard*
- effective systems and tools for managing risk
- regular review of existing risks and assessment of emerging risks
- understanding how robust risk management supports good decision making
- a culture of risk management awareness across all aspects of the business.

4.3.2 Risk Management Framework

Our Risk Management Framework outlines our processes and methods for ensuring the appropriate management of risk across the business. It ensures that risk management is integrated into all aspects of our business including governance, strategic planning, operational (day to day) planning, and reporting.

These activities are evaluated from the following aspects:

- Health and Safety (Public and Personnel)
- Environmental
- Legal and Regulatory Compliance
- Reputation and Stakeholder Confidence
- Customer Service Levels including Supply Reliability
- Financial
- Business Disruption

4.3.3 Risk management process

Our risk management process ensures our risks are identified, understood, and managed consistently across all levels of our business so that risks are assessed and tracked on the basis of likelihood and consequence outcomes.

Our risk management process involves the following steps:

1. Establishing the context in which the risks exist. This involves understanding our business objectives and values, defining the internal and external environment which we operate in, and setting the scope and risk criteria. We consider many factors, including accessibility of our assets by the public, asset age, and location.

2. Risk identification is the process of identifying, recognising, and describing our risks, and the effects those risks have. Our risks are identified through regular operational reviews, safety-in-design processes, and through lessons learnt from other businesses. Risks are recorded in appropriate risk registers that allow us to track and monitor the risks and the effectiveness of the controls.

3. Risk analysis. Risks are analysed using qualitative and quantitative methods to identify the likelihood and potential consequences that they present to the business.

4. Risk evaluation. All our identified risks are evaluated against our risk criteria. This assists us in our decision making to ascertain which risks need treatment, the priority for treatment implementation, and the level of investment that would be appropriate for the risk.

5. Risk treatment. We treat a risk depending on the outcome of the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, and these can include the following:

- Avoiding the risk by not commencing or continuing the activity
- Removing the risk source by doing the activity in a different way
- Changing the likelihood of the risk occurring
- Changing the consequences if the risk does eventuate
- Sharing the risk with another party or parties (e.g., contracts and insurance)
- Accepting the risk by informed decision.

6. Post treatment risk evaluation. The risks are reassessed after the application of the treatment to verify that the post treatment level of risk is known and accepted by the company.

7. Ongoing review of risks. It is important that once a risk is recorded in the system it is regularly reviewed, as the likelihood and consequence can change. Software risk registers are used to record and manage risks, including scheduling reviews, and reporting on outstanding risks.

4.3.4 Risk management plans

For complex activities such as major projects or where a new type of work is being introduced, we develop complete risk management plans, covering health and safety, financial, environmental, and operating risks for an activity. These plans are developed and approved by the key stakeholders involved in the activity in question, such as engineers, managers, and field staff.

4.3.5 Risk registers

Information from the risk management process is recorded, reported, and monitored using our risk registers. These cover:

- Public Safety Management System
- Health and Safety risks
- Business risks
- Asset risks
- Individual project risks
- Physical risks for specific sites

It is important that all risks can be tracked and managed in one system so that there is good visibility of the total risk that the business faces.

4.3.6 Risk reporting and monitoring

The risk register includes mechanisms for reporting and monitoring of risks and their treatments. This includes automated reviews based on set periods, dashboards to track the effectiveness of risk mitigation and the risk profile of the business. We have confidence that the monitoring and reporting processes in this area are robust and complete, with monthly reporting on risks in this area going to the board.

Some lower-level risks, such as project level performance and commercial risks, are monitored by the staff managing the project itself and are normally reported to management on an exception basis if the risk becomes a real threat.

4.3.7 Health and Safety Critical Risks

We maintain a special awareness and focus on what we consider to be critical risks associated with operating an electricity network. These risks have been identified and assessed in collaboration with our staff through an ongoing workshop process, using bowtie analysis. The critical risks of focus include:

- Health and wellbeing (mental health and fatigue)
- Traffic management
- Asset integrity
- Electricity
- Mobile plant and equipment
- Driving
- Working at height
- Dropped objects

The treatment of these risks includes special focus on training and the development of safe standard work practices, as well as regular monitoring of the risk profile and our performance in these areas.

4.4 Public Safety Management System (PSMS)

As an electricity network operator, we strive to manage our assets in a way that reduces to as low a level as reasonably practical any risk to our people, members of the public, and property . Under the Electricity (Safety) Regulations 2010, NWL is required to maintain a public safety management system to manage all known hazards and risks to the public or their property caused by the operation of our business. It records the actions to be taken (or that have been taken) to resolve those risks. Public safety risks are identified through operational processes such as documentation by field staff, and team and project meetings. This information is also reported to the Board monthly and in annual reports.

Our PSMS is certified to NZS7901 and is audited annually by an external auditor (Telarc). Internal auditors also work to provide assurance that the system is working effectively. In February 2021, we received confirmation that our PSMS again achieved certification to NZS7901:2008 and NZS7901:2014, and that the certification would not need to be renewed for three years.

4.5 Operational Resilience

Electricity distribution is a critical component of modern society. Businesses are dependent on electricity for production processes, IT operations and lighting. The general population depends on electricity for basic functions such as lighting, cooking and, increasingly, heating. Critical infrastructure such as water treatment and hospitals require electricity to function.

There are a number of potential events that could significantly disrupt our ability to deliver electricity. A significant event could disrupt our ability to perform our core functions by damaging key components of our network, causing business systems to fail or to operate at reduced capacity, affecting the availability of resources to operate the network, or disrupting our supply chain. Key examples of such events are:

- A large earthquake on the South Island's alpine fault
- A large earthquake on a fault line within the Waitaki region
- A tsunami
- A pandemic
- A large snowstorm
- A large wind storm
- Flooding
- Sustained loss of supply from Transpower's transmission system
- Cyber attack
- Sabotage

Thankfully the likelihood of many of these events is rare, with return periods ranging from decades to centuries. These sorts of events are often referred to as "high impact low probability" (HILP) events.

As the provider of a lifeline utility, we have a responsibility and duty to plan and prepare for HILP events. The Civil Defence Emergency Management Act 2002 requires Lifeline Utilities such as Network Waitaki to participate and plan for major events affecting the environment. In particular it requires utilities to:

- Function to the fullest extent during and after an emergency event
- Establish and maintain plans to enable this functioning
- Participate in CDEM planning at a regional and national level as required
- Provide technical advice and information to CDEM authorities where required.

Due to our Network being located in both the North Otago and South Canterbury geographic regions, we are involved as a member of both the Otago and Canterbury Lifeline groups. This provides us with information at regional and national levels into hazard and risk assessment, mitigation methods, and business practices. It also establishes relationships with other lifeline utilities and agencies. We also actively learn from other EDBs and communities that have been impacted by HILP events. This learning occurs through various channels, such as:

- Attending industry conferences such as EEA asset management forums.
- Involvement in regional peer industry groups such as the Combined Network Operations Group (CNOG).
- Involvement in Civil Defence workshops and exercises.
- Working with experienced consultants to carry out specific reviews of vulnerabilities in our assets and operations and develop remediation plans.

In the 100 years of operation of our network we have regularly been exposed to major flooding and snowstorm events. The knowledge and experience gained from responding to these disruptions have been fed back into our operational procedures, design standards and procurement standards to make our business more resilient.

We have also been working to improve the ability of our business to ride through an abnormal event such as a large earthquake, and to operate effectively in the aftermath of such an event. This has included working with experts in different fields to ensure that our electrical network and our business infrastructure are able to perform as expected after a disruptive event. Our goal is to ensure that during and after a HILP event our network and business systems are able to:

- Provide a safe environment for staff, contractors, and the wider community
- Reduce the potential damage to assets where this is economically viable
- Enable the timely restoration of power supply as far as practicable
- Allow us to effectively communicate with the public, Civil Defence Emergency Management, our staff, and other stakeholders
- Return to a "business as usual" mode of operations as quickly and as efficiently as practicable after an event.

The Covid 19 pandemic and the ongoing lockdowns proved an opportunity to trial the performance of many of our remote business systems and processes, with staff successfully working from home to keep our business as functional as possible under the restrictions at the time. We also carry out regular desk top exercises to test and tune our response plans and provide staff with experience in using them.

Resilience of our key infrastructure is being improved, with the reinforcing of our zone substations to meet importance level 4 (IL4) building rating by 2024. Our office and depot at Chelmer St are being redeveloped over the next three years including new or upgraded facilities with design features to ensure that our operations can continue after a disruptive event.

As part of our continual improvement programme, we continue to review and ensure that future risks are continually assessed. In particular, climate change is likely to have an impact on the environmental conditions that affect our network . We are continually reviewing research into impact on our environment and are currently collaborating with some other South Island electricity businesses to review our overhead design standards.

4.6 Asset Management Maturity

In 2021 we engaged with an independent assessor to review our Asset Management practices against good practice using the Commerce Commission's asset management maturity assessment tool (AMMAT). This assessment tool is a series of self-assessment questions based around the principles of the ISO55000 suite of standards for Asset Management. The questions cover particular facets of good asset management practice, with scores being applied to each ranging from 0-4 to reflect the maturity level of the organisation. The outcomes are also useful to identify gaps in our asset management systems. We are not currently seeking ISO55001[6] certification, but we will be looking to align our systems with the principles of those standards as part of the improvement plan to come out of the review.

4.6.1 Summary of AMMAT assessment

The latest assessment of our asset management practices against the AMMAT is attached in the Appendices. As an organisation we are applying many good practices in the asset management space and developing strengths in others, but we recognise that these initiatives have often been isolated and that our overall development strategy for asset management practices is not particularly mature.

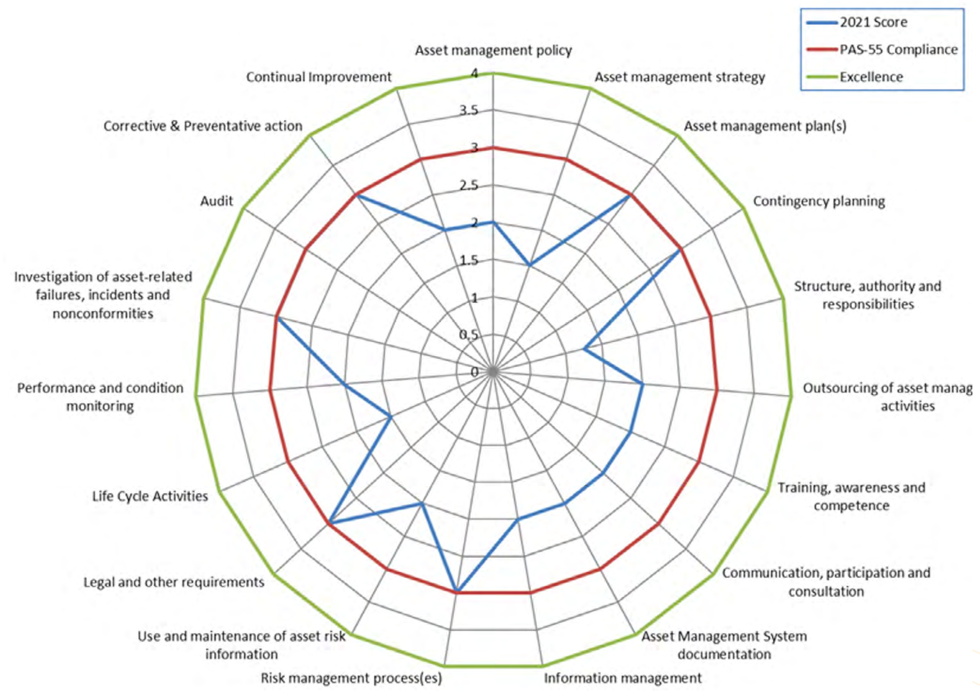


Figure 23 - AMMAT results summary

Our systems and processes are functional and have historically resulted in good network performance, but they are not particularly efficient and rely heavily on the specific knowledge of individual staff. We are still very reliant on manual data entry and processing. This reduces the efficiency of some of our activities, such as asset inspections, documenting project work and dealing with customer requests. It also reduces our ability to monitor and maintain oversight of our practices. Integration and coordination of data across our various systems can also require considerable human intervention, as can analysis of that data to generate useful information. We are actively involved in improving the efficiency and effectiveness of our systems through the introduction of field-based data capture systems, and the integration of data between software systems such as our GIS and our work management system.

[6] ISO 55001 – International Standard for Asset Management - Management Systems

4.6.2 Asset Management Maturity Development Plan

From this original AMMAT assessment point we have been working on improvement in various areas within the business focus areas, such as our control room operations, field service delivery and GIS systems. The latest business strategic plan includes a goal to achieve substantial alignment with ISO55001 good practice within the next five years. One of the overall effects of the new strategic plan will be to align and integrate asset management strategy with the broader business strategy. In the shorter term we are targeting several specific activities for improvement in some of the AMMAT assessment categories shown in Figure 20.

A key component for achieving this ISO 55001 alignment and improving our asset management capability has been an independent expert review of our capabilities, strategies, systems, and processes in this area. The outcome of this review enabled the creation of a strategic roadmap to guide the development of our asset management practices and systems, and to identify initiatives for focus. These initiatives are summarised in Appendix A.

Lifecycle management of all assets will be improved with the development of asset class plans to document good practice activities for all our assets. This work is expected to take two years to complete for all asset classes, with five high value and high-risk asset groups such as power transformers and switchgear being completed in 2023.

Improvement of our resilience planning has been a focus of efforts over the last two years, with a major review and overhaul of our business continuity plans and establishing a seismic resilience review and upgrade programme for our substations.

Ongoing updates to our risk management processes have included the adoption of better software tools for recording and analysing risk. Critical risks are undergoing bowtie analysis, and the integration of good practice risk management throughout the business is well underway.

A key strategic action in 2023 is improving our defects management system and integrating with our works planning systems. Having a system with the ability to record and view defects in the field, that allows us to a track and follow up on defects and the associated remedial work, will provide meaningful reporting. This can be used as a performance measure and provide insight for future Asset Management decisions.

4.6.2.1 Integration of asset management data

We operate several separate systems to manage our asset data, including some that are paper based, and some that are on old software platforms that are becoming difficult to support. We realise this is inefficient, and ongoing work aims to integrate this data across our business in digital form. The scope of this work includes data in our GIS, works planning and management, fault recording, and defect management systems, as well as others. This will improve understanding and awareness of network and asset performance and risks and provide for more efficient operation of the business.

Success with this project will result in staff being able to access asset data in the field, and to input information from the field directly into our asset records, rather than being captured on paper for later transcription into our systems. These systems have been trialled in the field in pilot projects, with good success, and have been placed into production with the broader work force. The establishment of our in-house vegetation management crews in the last 12 months has been based on the use of field capture and reporting tools.

Our vegetation management process has successfully been put into production in an online, end-to-end digital system. This allows vegetation management crews to easily capture and share inspection and mitigation data on tree hazards on and near the Network. Moving from a paper-based system has improved visibility of performance and issues, the efficiency of planning work, and communication with tree owners and other stakeholders.

We are working closely with peer EDBs and other organisations with similar systems and requirements to share knowledge and learn good practice. The goal is to ensure a tightly integrated system across the following areas:

- Works planning
- Maintenance scheduling
- Condition monitoring and analysis
- Financial management
- Timesheet integration for plant and staff
- Defects recording and location
- Management of controlled documents such as standards and policies
- Fleet management of plant
- Asset registers, operational, financial, and regulatory
- Stores and procurement
- SCADA Data

4.6.2.2 Improvement of asset data

Many areas of our asset data are complete and accurate, but there are still some deficiencies. This workstream will be ongoing for the next few years and will involve the digitisation of old paper-based records, field surveys and using personal knowledge of the network to close any gaps. The improved systems integration outlined in section 4.6.2.1 will help in the discovery of these knowledge gaps.

The focus of this work will initially be assets classed as critical or with higher levels of public risk attached, as well as those where a particular knowledge hole has a high potential impact (e.g., the current rating power of a cable, the manufacturer of a circuit breaker or the age of a battery).

Certain classes of asset have traditionally been managed with the age of the asset being used as a marker for replacement decisions. We are reviewing the collection and analysis of condition data for asset classes where there is a gap in condition information so we can establish measures and record data to build a future works programme based more on condition and risk factors and less on strict age-bound criteria.

An example of success in this area is the adoption in recent years of better inspection techniques and inspector training for pole condition assessment. These initiatives have improved the quality and reliability of pole condition data being returned from inspections and allowed us to develop meaningful rates of renewal that provide better insight into future investment needs.

4.6.2.3 Understanding asset criticality

A focus of the early part of the planning period is the analysis of the true criticality of assets in the network. Although the criticality of some major components and sections of the network is well understood from an operational point of view, we lack a formal criticality analysis for all assets. Having this rating available will provide a mechanism to assist in planning the most efficient and effective execution of planned work, and assist in improving network resilience, as we will be able to focus resources on the parts of the network where they will give the greatest benefit.

Our network controllers, engineers and planners are working with major customers and other stakeholders to complete risk assessments to identify critical assets that may have a disproportionate impact on customer experience and to ensure that these are dealt with appropriately. In the short term this is reflected in the ongoing review of contingency plans that will help us respond rapidly and effectively to critical emergency events, such as the loss of a major sub-transmission feeder.

4.6.2.4 Quantifying risk and obtaining value

An Asset Owner who only replaces assets once they have failed is not an Asset Manager. The first step in the path is developing a planned set of interventions such as inspection, testing and/or maintenance. This enables a better understanding of asset condition and rate of deterioration.

Once the Asset Condition is understood the level of intervention can be optimised, allowing more efficient allocation of resources such as staff and funding, as well as reducing disruption and improving reliability.

Combining Asset Condition with Criticality through the lens of our Risk Framework allows us to understand the overall risk to be managed and lets us identify the highest risks across all asset classes and the wider business. However, simply prioritising our resources to the biggest specific risks is not necessarily the most effective or efficient form of management.

We must also understand both the cost to mitigate any risk along with any risk that will remain once that mitigation is carried out. This results in value propositions that can be understood within the wider business sense.

4.6.2.5 Asset Management Development Path

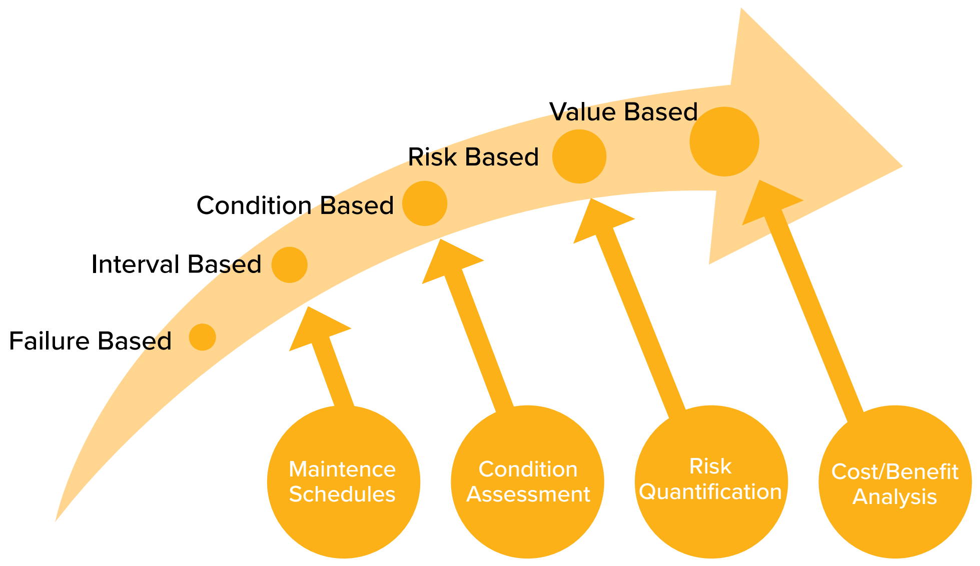


Figure 24 - Asset Management Development Path

Network Waitaki's assets are currently managed with varying degrees of maturity depending on their criticality and the cost/benefit of the relevant asset management regimen. Most assets are managed using condition as the basis for decisions, but poles and transformers use a risk-based approach informing their management strategy. More assets will have risk quantification applied in 2023.

Maintenance and Renewal

05

Maintenance and Renewal

In this section we have taken a consistent approach for each asset class:

- Describing the assets and their purpose within the system
- Profiling their age and current health
- Identifying and describing key risks associated with each class
- Detailing our processes for inspection and maintenance
- Describing our Renewal and Replacement criteria and plans

Asset description and purpose - We have typically grouped asset classes by function and their associated asset management processes and practices. This continues to be reviewed as our system information and the maturity of our processes develop.

Age and health - An age profile is provided but it is the health of an asset that is of prime consideration. The Health Index (HI) uses multiple factors including test and inspection results, type data and, to a limited extent, age. This Health index can correlate to Probability of Failure (PoF) of each individual asset. Health Index values are described below:

1. No longer fit for purpose, replace immediately
2. Near end of economic life, allow for replacement in plan
3. Fit for purpose but has signs of ageing/degradation
4. Normal in-service condition
5. As new

Asset Risks - We have evaluated the performance of the asset class in relation to its historical failure rates (faults per 100km or item) and contribution to SAIDI and SAIFI. The risks associated with failure modes of these assets are identified and described.

Inspection and maintenance - The failure causes and mitigation or control measures for any asset category help inform us of the appropriate inspection and maintenance regime. This, along with continually monitoring asset health provides context for the asset condition, maintenance, and replacement plans. We provide the scheduled maintenance work plans that keep the asset serviceable and prevent deterioration or in-service failure.

Renewal and Refurbishment - These are major works that do not increase the asset's design capacity but restore, replace, or renew an existing asset to its original capacity or extend its expected service life. A summary of upcoming programmes and work is also included. Replacement expenditure forecasting is based on known historical replacement costs and projected replacement volumes.

5.1 Asset Summary

The assets that make up our network are summarised in the table below. The renewals and maintenance that we apply to these assets are the primary means by which we achieve the service levels laid out in Chapter 3 and retain the value of the assets for our owners.

Table 13 - Summary of network assets by category

Asset category	Section	Unit	Quantity
Concrete poles		No.	9,130
Wood poles		No.	12,474
Sub-transmission OH up to 66 kV conductor		km	234
Sub-transmission UG up to 66 kV (XLPE)		km	4
33 kV Switch (Pole Mounted)		No.	94
33 kV CB (Indoor)		No.	11
33 kV CB (Outdoor)		No.	51
11 kV CB (ground mounted)		No.	84
11 kV CB (pole mounted)		No.	4
Zone Substation Buildings		No.	
Zone Substation Transformers		No.	23
Distribution OH Open Wire Conductor		km	1,255
Distribution UG XLPE or PVC		km	71
Distribution UG PILC		km	13
11 kV CB (pole mounted) - reclosers and sectionalisers		No.	56
11 kV Air Break Switches and Fuses (pole mounted)		No.	4,032
11 kV RMU (individual switches)		No.	199
Pole Mounted Transformer		No.	2,389
Ground Mounted Transformer		No.	560
Voltage regulators		No.	38
LV OH Conductor		km	222
LV UG Cable		km	104
LV Switchgear (Distribution Boxes)		No.	317

5.2 Asset Categories

For the purposes of planning renewals and maintenance we group our network assets into the following functional areas:

- Zone substations
- Sub-transmission network
- Distribution network
- Secondary and support systems

Maintenance and renewal management plans for each of these groups are detailed in the following sections.

5.3 Maintenance Planning

Maintenance falls into four main categories:

- Preventative maintenance, which includes routine activities such as inspections, scheduled maintenance, and condition monitoring.
- Corrective maintenance, which can include defect correction and renewals.
- Reactive maintenance, which involves dealing with faults and service interruptions, and restoring supply to customers; and
- vegetation maintenance, which is the inspection and management of trees and other vegetation around our assets, in accordance with the Electricity (Hazards from Trees) Regulations 2003 and good industry practice.

Our preventative maintenance programme is primarily time based. Assets are inspected and serviced at regular intervals, based on manufacturer's recommendations, industry good practice, or local experience. The primary goal of these inspections is to verify that the assets continue to operate safely and correctly, provide a condition assessment of the assets, and to identify any defects or risks that may be present.

Preventative maintenance activities outlined in the following sections are based on the estimate of the number of assets that will fall due in a particular year, and the estimated cost per activity.

Our objective is to discover any non-compliance or defects and complete work to remedy the defect before it becomes a hazard, causes an outage, or damages the asset. The results of the routine inspections, fault reports and defect reports can trigger specific reactive maintenance or renewal activities on certain types of assets or in particular areas of the network. Other triggers for renewals or maintenance can also come from patterns of faults reports that may reveal a developing problem or from wider industry advice of an issue with a particular asset type.

Corrective maintenance activities in the following sections are based on estimates of defects that may be discovered in a particular year and the estimated costs of remedy. Where possible this failure rate is based on empirical condition and failure rate data, although where this is not available, we will use historical expenditure trends, or industry failure rates, often based on the age profile of the asset type. Where we have used expected failure rates based on existing age and condition profiles, we have confidence in the first five years of the plan but expect that the accuracy of these estimates will reduce in the final five years of the plan.

NWL field staff carry out the inspection and maintenance for most of our assets. We provide inspection staff with specialist training and tools such as thermal imaging cameras, partial discharge detectors and acoustic and x-ray imaging pole testing equipment to inspect our assets. External contractors and laboratories are used to undertake certain detailed and technical assessments such as dissolved gas analysis (DGA) and partial discharge (PD) analysis of key assets such as substation transformers and cable terminations.

5.4 Renewals Planning

Planned renewals and replacements are undertaken to ensure network safety and reliability. The difference between renewal and maintenance actions is often around the scale of the work to be carried out on an asset. Common drivers in the renewal programme are age and/or general condition of a group of assets.

Renewal may also be carried out to ensure that an asset or system will continue to meet its performance requirements, such as capacity or speed of operation. Wherever possible we use asset condition when planning renewals, although where suitable condition data is not available, we may use asset age as a proxy for renewal or replacement triggers.

Economic analysis is also completed to decide whether an asset is renewed (i.e., substantially rebuild or overhauled) or removed from service and replaced. If an asset is to be replaced the operational requirements throughout the expected life of its replacement are identified and specified. This includes aspects such as capacity (decarbonisation/demand changes), functionality (technology/customer expectations), strength (climate change/new standards) and end of life disposal (sustainability/safety).

5.5 Data Improvement

As mentioned previously, of the key areas we are working on improving is the asset data that we collect and base decisions on. This includes fixed attributes such as manufacturer, model numbers and capacities, as well as operational data such as demand profiles, condition, location, and relationship with other assets on the network.

Some of this data, such as geographical location and relationship of one asset to the rest of the network, are available and reliable for almost all of our assets. Some asset types such as poles have good condition data available, but incomplete age data. Some asset types such as distribution transformers have good age data available, but incomplete information on demand profiles. We are working to identify and close these gaps based on the criticality of the information for asset management decision making.

Asset Health is primarily based on condition information. The condition information can be further separated into objective (test results) and subjective (visual assessment) data. Where assets lack suitably robust condition data, then modelling using parameters such as type (make and model), location (environmental/pollutants) and age are used.

Utilising field capture of key information will help in this improvement area. Many of our data capture activities are currently paper based, which leads to difficulty with data analysis and linking of data, and with the efficient sharing of asset information between parts of the business.

5.6 Zone Substations

5.6.1 Overview of zone substations

Zone substations house the equipment that connects the bulk electricity supply at sub-transmission voltage to our customers for end use. Power transformers convert electricity from 33 kV, which allows efficient transfer of large amounts of energy to 11 kV, allowing for the cost-effective connection of end user demand. Switchboards and other switchgear allow the safe and reliable connection of supply to multiple areas from a central point via 11 kV feeders that are monitored by protection relays to swiftly disconnect the supply in the event of a fault.

Our zone substations are summarised in the following table. We also own assets at two Transpower GXPs, which are functionally treated under the same regime as our zone substations for maintenance and renewals.

Table 14 - Summary of NWL zone substations

Zone Substation	GXP	Capacity (MVA)	Number of Customers	Security Level	Year Built	Number of Feeders	Transformer Year of Manufacture	Switchgear Year of Manufacture
Ohau	Twizel	3	140	N	2006	3	1959	1997
Omarama	Twizel	3	462	N	1984	3	1960 & 1963	1985
Ruataniwha	Twizel	2	18	N	2015	1	1971	None
Otematata	Waitaki	3	529	N	1973	2	1961	2017
Kurow	Waitaki	12.5	744	N-1	1991	5	1966 & 1979	2015
Eastern Rd	Waitaki	7	123	N	2020	3	2005	2018
Duntroon	Waitaki	7	212	N	2010	4	2010	1969
Ngapara	Oamaru	7	354	N	1970	4	2005	1972
Papakaio	Oamaru	7	391	N	2006	4	2012	2006
Enfield	Oamaru	7	317	N	2006	3	2005	2006
Five Forks	Oamaru	7	169	N	2017	3	2005	2016
Parsons Road	Oamaru	10	1,081	N	1970	4	1966	2018
Weston	Oamaru	-	0	N-1	2005	-	-	2005
Pukeuri	Oamaru	12.5	446	N-1	1971	5	1966 & 1966	2017
Chelmer Street	Oamaru	28	4,068	N-1	1967	8	2009 & 2009	2009
Redcastle	Oamaru	15	2,326	N-1	1967	6	2014 & 2014	2008
Maheno	Oamaru	5	1,013	N	1967	4	1965	2019
Hampden	Oamaru	7	805	N	2010	3	2012	1968
Waitaki GXP	Waitaki	24MVA	100	N	2013	1	2013	2013

Note: The security grade refers to the security of supply based on the equipment at the substation, and does not factor in the ability for load to be switched to surrounding substations during an outage.

5.6.2 Management approach

Our zone substation assets are critical assets, as a component failure can have a significant impact on system reliability and many customers.

Our objectives for the maintenance of zone substations assets are:

- Keep our people and members of the public safe.
- Maintain the reliable supply of electricity to our distribution network and minimise supply interruptions.
- Ensure that zone substations are operable in a post disaster scenario.
- Maintain the value of our investments and prevent negative effects on the neighbourhood.

5.6.3 Zone substation buildings, fences, switchyards, and grounds

Our zone substation buildings are specifically designed for accounting for their location and criticality. They are mostly constructed with reinforced, concrete filled blocks. We continue to invest in strengthening them based on the experience gained by other infrastructure businesses.

5.6.3.1 Age profile and population data

We expect zone substation building to have an average life of 70 years. The age/health profile shown in the following graph is based on the establishment date of the substation. In several cases the buildings, switchyards and fences have been partially rebuilt in the intervening years.

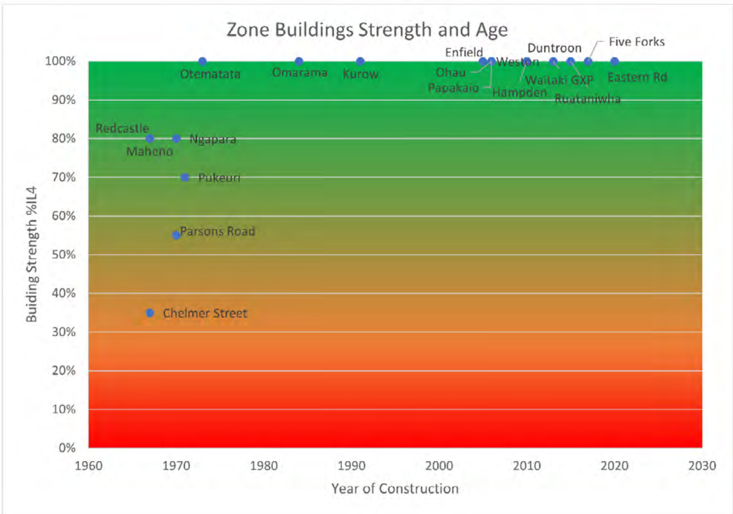


Figure 25 - Age and Strength profile for zone substation buildings

5.6.3.2 Asset risks

Specific risks and issues associated with this asset group include:

- Security breach due to fence condition, failure of locks, etc.
- Damage due to animal ingress into yard (e.g., possums) or into switch room equipment (e.g., mice).
- Water/weather ingress into switch room.
- Work hazards due to condition of switchyard surfaces, including surface levelling, weeds, etc.
- Failure of lighting, heaters, and other secondary equipment.
- Electrical hazards from rubbish, straw, and other foreign materials inside switchyards.
- Condition of firefighting equipment, oil spill equipment, etc.

5.6.3.3 Inspection and maintenance programme

Table 15 - Zone substation buildings, fences, switchyards and grounds inspection and maintenance programme

Activity	Summary	Frequency
Routine visual inspections	All equipment at substation. Check for defects, weeds, issues with weather tightness, housekeeping, pest control etc. Special attention to site security, fences, etc.	3 months
Detailed inspection	Detailed condition assessment of fencing, building envelope, bus structures, etc.	5 yearly
Earthing system test	Specialist test of the performance of the substation earth mat.	5 yearly

5.6.3.4 Renewal and refurbishment programme

In line with our commitments to prepare for HILP events (see section 4.5), our substations need to be able to operate immediately after an earthquake or other disaster and are therefore required to meet importance level 4 (IL4) under the New Zealand Building Code. In 2019 we assessed the seismic capacity of our substations against the new building standard for IL4 (% NBS IL4). A remediation plan was developed, and remedial work began in 2020. The following table shows the work plan that remains, which will be completed over the first year of the planning period.

Table 16 - Zone substation remediation required to achieve IL4

Substation	% NBS IL4	Risk level	Structural work	Non- structural work	Land remediation	Target date
Waitaki GXP	100%	Low	N/A	N/A	no	Complete
Kurow	100%	Low	N/A	Minor	minor	Complete
Twizel	100%	Low	N/A	N/A	no	Complete
Ruataniwha	100%	Low	N/A	N/A	no	Complete
Ohau	100%	Low	N/A	N/A	no	Complete
Omarama	100%	Low	N/A	N/A	no	Complete
Otematata	100%	Low	N/A	Significant	no	Complete
Pukeuri	70%	Low	Required	N/A	no	Complete
Five Forks	100%	Medium	Required	Minor	no	Complete
Hampden	100%	Medium	Required	Minor	no	Complete
Papakaio	100%	Medium	Required	Minor	no	Complete
Duntroon	100%	Medium	Required	Minor	no	Complete
Enfield	100%	Medium	Required	Minor	yes	Complete
Redcastle	80%	Medium	Required	Significant	no	Complete
Maheno	80%	Medium	N/A	N/A	no	Complete
Parsons	55%	Medium	Required	Minor	no	End of FY23
Ngapara	80%	Medium	N/A	Minor	minor	Complete
Weston switch room	100%	Medium	N/A	N/A	no	Complete
Chelmer St	35%	Medium	Required	Minor	minor	End of FY24

The work ranges from spot strengthening actions at some substations through to the addition of significant internal steel reinforcing frames in others. A few sites also require some work to be carried out on the surrounding environment (streambanks, slopes) to reduce risks.

Other refurbishment and renewal programmes include repair, upgrade or replacement of fencing and security systems based on condition assessment, and how effective they are compared with current security standards. Other defects such as damage to buildings are remedied as they are found.

The transformer bunds at Otematata and Omarama substations will also be upgraded as part of the seismic work.

5.6.4 Zone substation transformers

Power transformers are installed at zone substations to transform sub-transmission voltages to a distribution voltage of 11kV. They are fitted with on-load tap changers and electronic management systems to maintain the required delivery voltage on the network.

5.6.4.1 Age profiles and health data

We expect power transformers to have an average service life of 60 years. The age used in the following graph is the date of manufacture of the transformers and the health index is based on the Electricity Engineers Association Asset Health Indicator Guide.

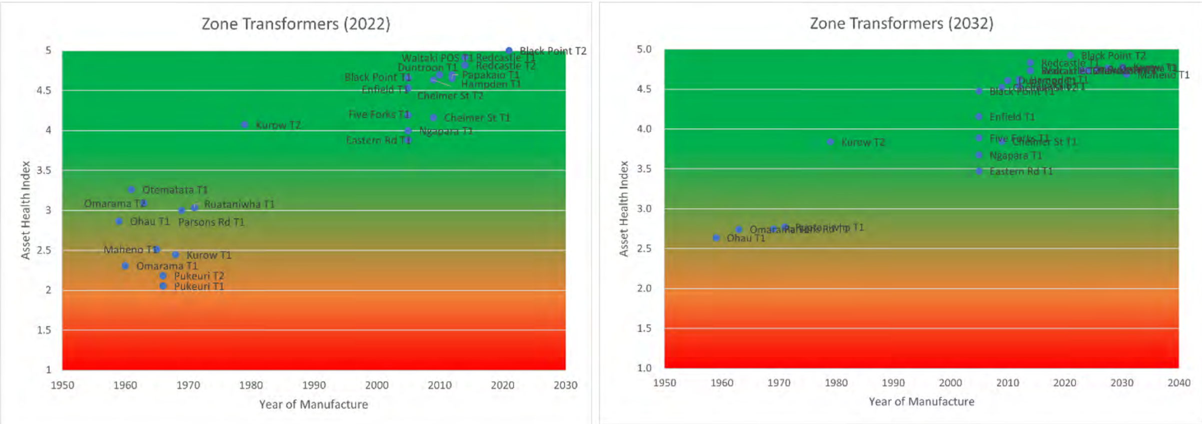


Figure 26 - Zone transformers age and health profile 2022 and 2032 (forecast)

5.6.4.2 Asset Risks

Risks and issues commonly associated with zone substation transformers include:

- Degradation of paper insulation resulting in damage during faults
- Reduction in life due to oil degradation
- Catastrophic failure due to internal electrical fault
- Online tap changer failure
- Reduction in capacity due to cooling system (radiators and fans) failure
- Environmental damage due to oil leaks
- Electrical failure due to cracked or damaged bushings
- Moisture ingress into transformer due to dehydrating breather system malfunction
- Reduction in life due to corrosion
- Damage in an earthquake due to failure of seismic hold-down equipment

5.6.4.3 Inspection and maintenance programme

Table 17 - Zone substation transformers inspection and maintenance programme

Activity	Summary	Frequency
Routine visual inspection	As part of regular sub inspections.	3 months
Partial discharge tests	As part of substation PD testing.	12 months
Transformer detailed inspection	Detailed inspection. Includes expert inspection, thermal imagery, DGA and oil testing.	12 months
Transformer tap changer maintenance	Servicing of tap changer and associated equipment. SFRA and other offline testing carried out during work.	3 yearly, or 10,000 operations

5.6.4.4 Renewal and refurbishment programme

Zone substation transformers are a long lead time item, in that procurement of replacements can take 12 months or more. For this reason, we aim to maintain these assets in good condition, and to predict end of life with sufficient notice to secure replacements. In the case of an unforeseen failure, contingency arrangements are in place for all transformers based on the criticality of the site and utilising a hierarchy of controls, including:

- Energised spare on site (N-1)
- Transferral of load to adjacent sites (N-1 Switched)
- De-energised spare on site
- Compatible energised spares at other sites

Transformer on-load tap changers are refurbished every three years, or 10,000 operations, whichever comes first. Analysis of our historical refurbishment work indicated a historical under-budgeting in this area, so the forecast for this programme has received an uplift in this plan.

Maintenance activities such as oil treatment or streamlining are triggered by trends detected during DGA testing.

Minor defects such as a damaged breather or cracked bushing are remedied soon after they are detected, as the repair work is relatively simple. Major refurbishment of transformers is based initially on age (mid-life) and then condition and operation characteristics (late-life). An older transformer that shows good results for oil and paper condition in routine testing (such as DGA tests) can be a good candidate for late-life refurbishment, which will generally involve core de-tanking for dry out and tightening, as well as refurbishment of the tank, replacement of fans, radiators and auxiliary systems as required.

Replacement decisions for transformers are based on the assessment of factors such as having outdated major systems (e.g., tap changers) that cannot be adequately supported, incompatible vector group for normal operation or the condition of insulating paper as determined by DGA testing.

We follow international good practice to ensure that our transformer condition assessment processes are delivering good outcomes. As can be seen from the age profile, several of our transformers will reach or surpass the standard asset life within the planning period, with nine units currently more than 50 years old. Annual DGA and inspections indicate that most of our fleet are in good condition for their age and are likely to continue to operate safely and reliably. We will look to extend the life of these transformers if it is economic to maintain them in operation, or until reinforcement or capacity upgrades force their retirement.

Capacity upgrades at some substations as part of the network development plan (see chapter 6) will influence this replacement programme, as this work may free up younger existing transformers that can replace older units. At this stage we are budgeting to purchase a spare transformer and replace two transformers of 3 MVA capacity and three of 10/12 MVA capacity within the planning period. The replacements have been planned based on insulating paper condition trends that have been noted in recent assessments.

5.6.5 Zone substation switchgear

Zone substation switchgear allows the control of the individual high voltage circuits that radiate out from the substations. The switchgear provides a safe and convenient way to energise and de=energise sections of the sub-transmission and distribution networks for clearance of faults, or to carry out work.

5.6.5.1 Age profile and asset data

We expect zone substation outdoor switchgear to have an average service life of 40 years and indoor switchgear 45 years.

The health profiles in the following graphs are based on the Electricity Engineers Association Asset Health Indicator Guide. The units with the lowest health ratings are in Duntroon, Hampden and Ngapara substations and are all scheduled for replacement in the next 3 years.

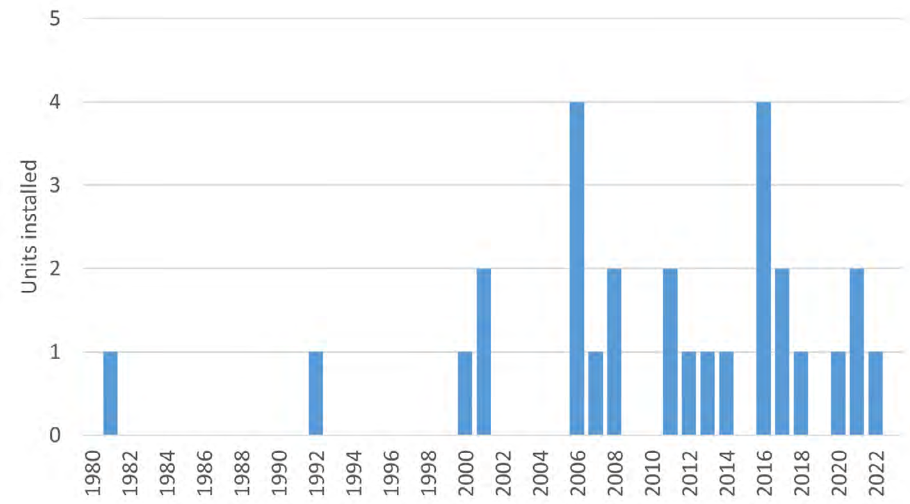


Figure 27 - 33 kV circuit breaker age profile

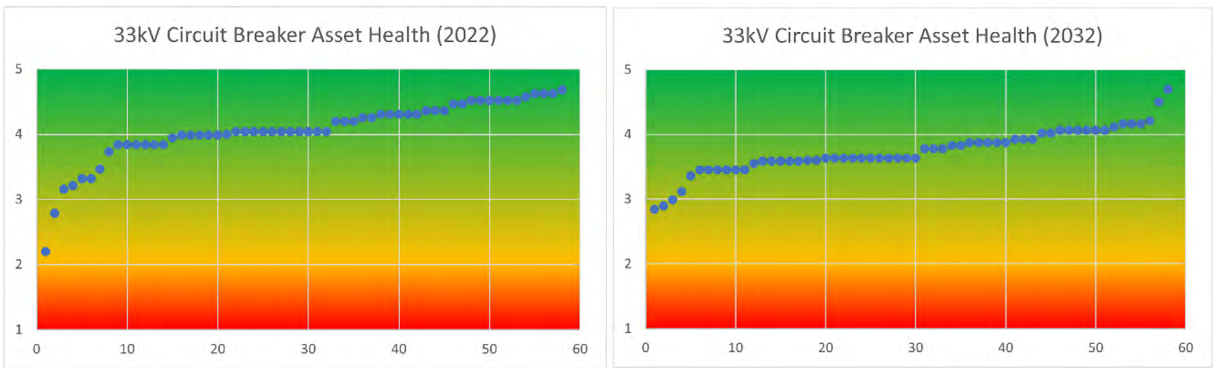


Figure 28 - 33 kV circuit breaker Asset Health

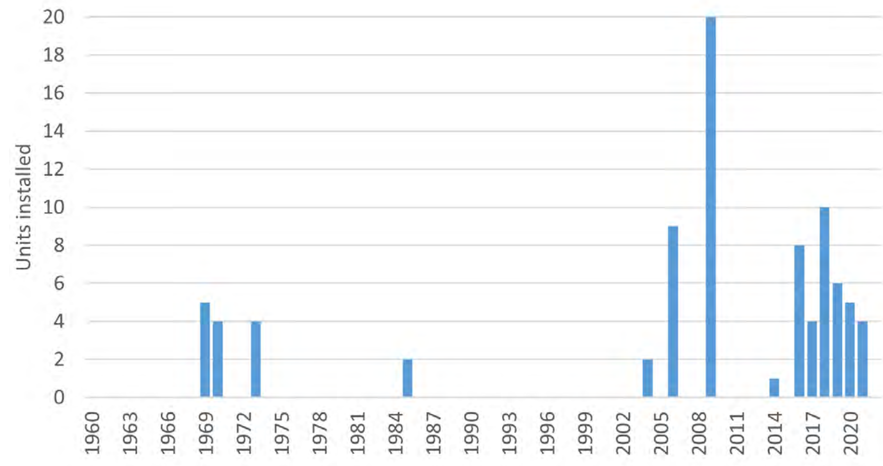


Figure 29 - 11 kV circuit breaker age profile

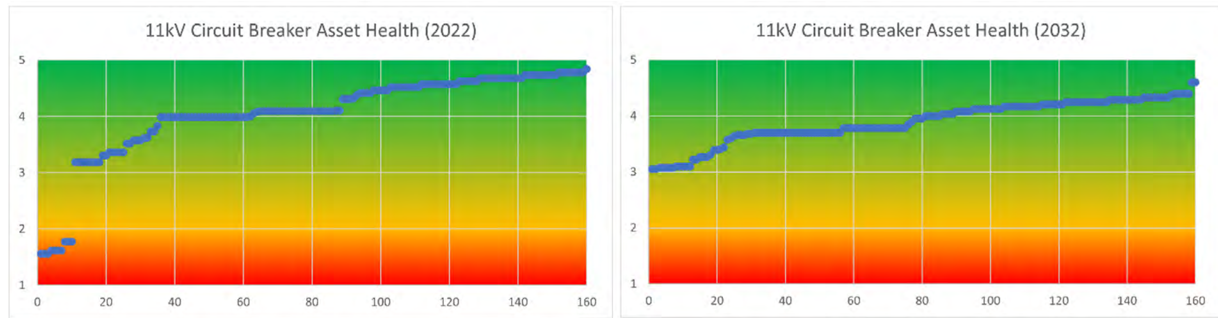


Figure 30 - 11 kV circuit breaker Asset Health

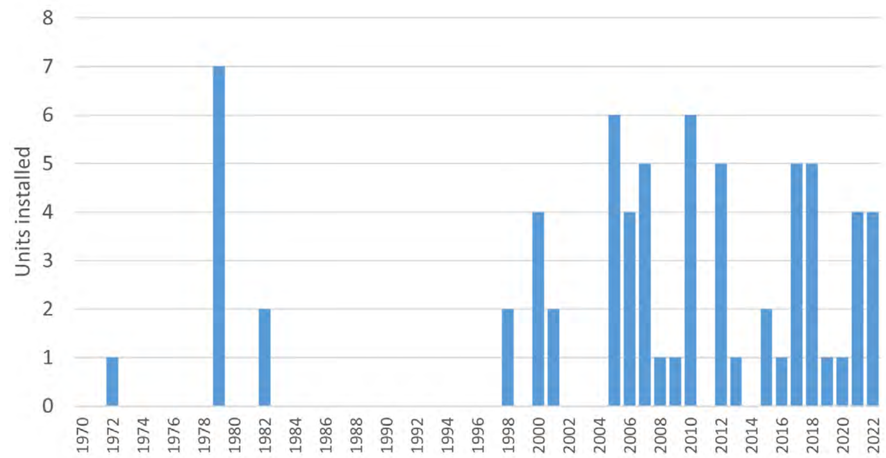


Figure 31 - Zone Substation Isolator Age Profile

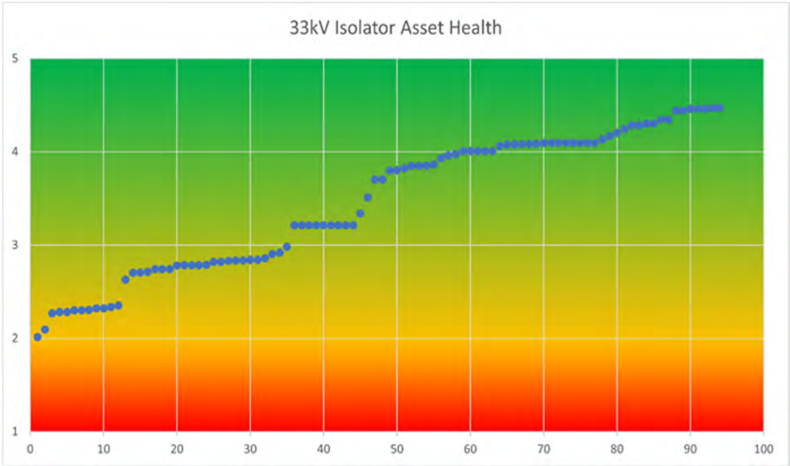


Figure 32 - Zone Substation Isolator Asset Health

5.6.5.2 Asset risks

Common issues and risks associated with this asset group include:

- Degradation of oil insulation in older switchgear
- Mechanisms binding and slowing down
- Overheating conductors (busbar, joints, terminations)
- Partial discharge (cable terminations, busbar chambers)
- Arc flash hazard to operators due to switchgear design and type
- Isolator contact damage
- Cracking porcelain insulators

5.6.5.3 Inspection and Maintenance Programme

Table 18 - Zone substation switchgear inspection and maintenance programme

Activity	Summary	Frequency
Visual external inspections	As part of regular inspection	3 monthly
Detailed switchboard inspection (non-invasive)	Partial discharge testing, thermal imaging of boards, CBs, cable terminations etc.	12 months
110kV or 33kV gas insulated CB maintenance	Insulation, contact resistance and operational tests.	5 yearly
33kV or 11kV vacuum insulated CB switchboard maintenance	Insulation, contact resistance and operational tests.	5 yearly
11kV oil filled CB switchboard maintenance	Service of oil CBs. Insulation, contact resistance and operational tests.	3 yearly/3 high current fault operations

5.6.5.4 Renewal and refurbishment programme

A programme is underway to replace older (pre-1990) oil insulated switchboards with modern, arc-fault-rated switchboards fitted with vacuum-insulated circuit breakers. Four switchboards remain to be replaced, at Ngapara, Hampden, Duntroon and Omarama zone substations; all are scheduled for replacement in the planning period. Drivers for replacement include the age and obsolescence of equipment making maintenance and repairs difficult, minor age-related failures causing reliability problems, and the poor safety performance of the type of switchgear in the event of an arc flash fault.

We are in the process of retrofitting arc-fault-rated doors and arc flash detection systems to the more modern switchgear in our zone substations. Installations are scheduled based on fault level and other work that is being completed on switchgear.

Outdoor switchgear (33 kV and 11 kV vacuum/gas-insulated circuit breakers and air break switches) are replaced based on condition assessment or as they become obsolete, and the management of spares becomes problematic. We expect to replace two examples of this switchgear in the planning period.

There is a known problem with a particular brand of 33 kV air break switch where the porcelain insulators crack and fail. We carry out detailed inspection of these ABS at twice yearly intervals to check on signs of cracking and will be replacing all examples of this type of insulator during the early part of the planning period.

Substation cables are replaced or re-terminated based on the results of condition assessment (such as PD inspection) or based on age and type (e.g., old paper lead insulated cables) when replacement of associated equipment occurs, such as switchgear or power transformers.

5.6.6 Zone substation DC systems

DC systems at substations include the battery chargers and batteries. These systems are considered critical to the network, as they enable the operation of network equipment such as protection relays and circuit breakers in the event of the loss of mains power.

5.6.6.1 Age profile and population data

We expect zone substation DC supplies to have an average service life of 20 years with the batteries having an expected serviceable life of 7 years. A profile showing the asset age of the main DC systems is below.

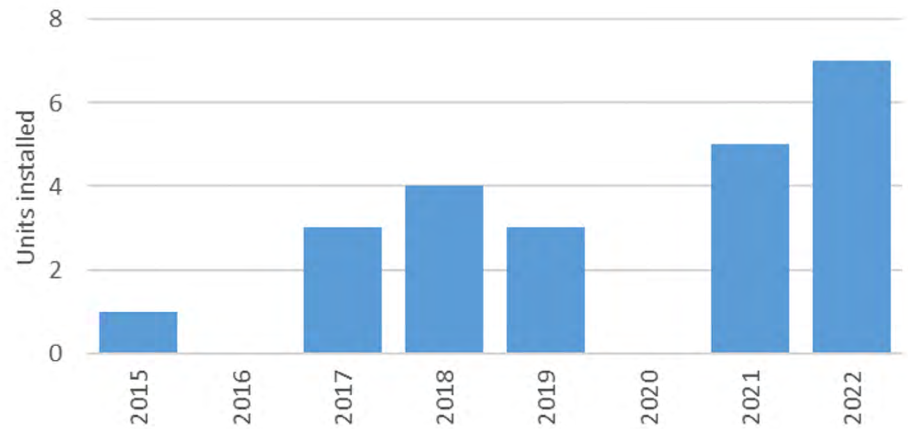


Figure 33 - Age profile data for zone substation batteries

5.6.6.2 Asset Risks

Specific risks in this asset group include:

- Corrosion on battery terminals
- Loss of battery capacity
- Internal failure of batteries
- Failure of battery charger
- Damage to equipment during seismic event

5.6.6.3 Inspection and maintenance programme

Table 19 - Zone substation DC systems inspection and maintenance programme

Activity	Summary	Frequency
Visual inspection	As part of regular sub inspections	3 months
Battery testing	Routine testing of battery bank	12 months
Discharge testing	Discharge testing of battery banks	2 yearly

5.6.6.4 Renewal and refurbishment programme

Substation batteries are critical to the ongoing operation of the network. We currently plan to replace complete battery banks after no more than 7 years of life, to ensure that they will be fully capable of operating when required. Individual cells or entire banks may be replaced depending on the results of discharge testing before then. We will be monitoring the performance of more modern batteries to see whether modern charging management is increasing this useful life. We expect to replace up to five battery banks per annum. A stocktake and review of existing systems was completed in FY21 to close the information gaps around the age of some of the battery banks.

Battery chargers and associated switchgear are replaced based on age (if obsolescent) and operating performance. These systems are generally up to date and in good condition. As we replace older systems, we are installing smart chargers that provide detailed operational information through the SCADA system and will review DC system functionality and capacity during any upgrades.

5.6.7 Zone substation protection relays

Protection relays detect faults on the network and signal the circuit breakers to open and remove the supply to the affected assets. The key attributes of this equipment are that it is sensitive and reliable, so that public safety and network performance is maintained.

All the protection systems at our substations are of the modern digital type and are reasonably up to date and performing satisfactorily. All our substation protection relays are connected to our SCADA systems and are remotely controllable.

5.6.7.1 Age profile and population data

We expect protection relays to have an average service life of 40 years, although technological development and changing operational requirements often mean that the relays are superseded before this. A profile showing the asset age of the relays is below.

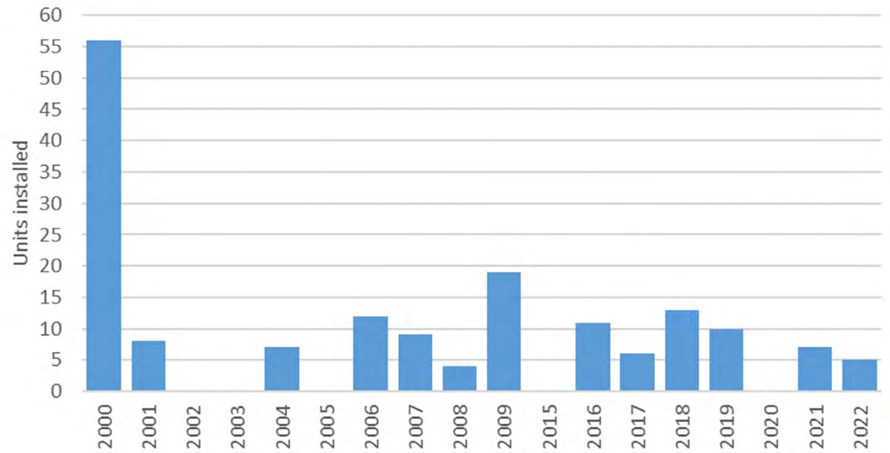


Figure 34 - Age profile data for protection relays

5.6.7.2 Asset risks

Specific risks in this asset group include:

- Failure of a protection device to operate, putting staff or the public in danger.
- Obsolescence of protection device leading to improper operation in the network.

5.6.7.3 Inspection and maintenance programme

Table 20 - Zone substation DC systems inspection and maintenance programme

Activity	Summary	Frequency
Visual inspection	As part of regular sub inspections	3 months
Detailed protection relay assessment	Confirm settings and test operation, check, and replace onboard batteries, check terminals and wiring.	5 yearly

5.6.7.4 Renewal and refurbishment programme

We are working through a programme to replace some older feeder protection relays (SEL 551 type) with more advanced designs that offer better operational flexibility.

We also take opportunities to improve the quality of our protection relay network when we can, as with the commissioning of differential protection on sections of our 33 kV sub-transmission network. These projects are generally carried out as part of wider project work, such as replacement of a switchboard or transformer.

There are no other specific condition-based replacement plans for protection relays currently, and neither are there obsolescence issues with the current fleet of relays. However, we have allowed an ongoing budget for replacement of protection relays that have been in operation for more than 20 years, as it is likely that we will begin to get some failures in the population from that point.

5.6.8 Zone substation Ripple Control transmitters

Our Load Management (Ripple) System controls electrical loads predominantly by injecting frequency signals over the electricity network. The primary purpose is to defer energy consumption and minimise peak load. This is achieved in two ways: Customer demand management load reduction and/or generation and by distributor-controlled load management through hot-water cylinders and other interruptible loads. A secondary purpose of the system is to allow coordinated management of common load types such as streetlighting.

NWL owns and operates Landis & Gyr solid state 33 kV Ripple Injection Plants at each Oamaru and Twizel GXP. An indoor Landis & Gyr solid state 11 kV injection unit is installed at the Kurow Zone Substation and services the demand connected to the Waitaki GXP. We own the ripple control relays installed at customers' premises and these are discussed further in section 5.9.6.

5.6.8.1 Age profile and population data

We expect ripple transmitters and their associated equipment to have an average service life of 40 years. Transmitters are located at the following sites:

Table 21 - Ripple control transmitters by installation date

Zone substation	GXP(s) served	Year Installed
Kurow	Waitaki	1999
Twizel	Twizel	2005
Parsons Rd	Oamaru	2013

5.6.8.2 Asset risks

Specific risks for ripple control transmitters include:

- Failure of power electronics in transmitter
- Failure of coupling cell component

5.6.8.3 Inspection and maintenance programme

Table 22 - Zone substation ripple control inspection and maintenance programme

Activity	Summary	Frequency
Visual inspection	As part of regular substation inspections	3 months
Detailed ripple control plant inspection	Check operating signals, test coupling cell components	Annually

Further monitoring, testing and maintenance of the SCADA System is part of a support contract with the SCADA system provider.

5.6.8.4 Renewal and refurbishment programme

Our ripple control transmitters are still within their expected lifespan, but they are a highly critical piece of equipment, and the system configuration does not allow for mutual support between all units in the event of the failure of one. For this reason, we hold critical spares for these plants.

We expect that ripple control will be rendered obsolete by 2035 due to displacement by new smarter technology or the next generation of smart meters. As a result, we are not forecasting any replacement of ripple plant in the planning period.

We will maintain a watching brief on this situation and adjust this programme accordingly. We intend to maintain our ripple control capability until after any alternatives are established and proven.

5.6.9 Total zone substation expenditure forecast

Table 23 -Total zone substation expenditure forecast

Zone Substations ($000)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Service Interruptions & Emergencies	0	0	0	0	0	0	0	0	0	0
Routine & Corrective Maintenance and Inspections	339	325	310	310	310	310	310	310	310	310
Asset Replacement & Renewal (Pukeuri Transformer 1)	99	565								
Asset Replacement & Renewal (Pukeuri Transformer 2)		96	565							
Asset Replacement & Renewal (Omarama Transformer 1)					100	450	115			
Asset Replacement & Renewal (Kurow Transformer 1)							100	450	115	
Asset Replacement & Renewal (Maheno Transformer 2)									100	450
Asset Replacement & Renewal (Duntroon Switchgear)	96	366								
Asset Replacement & Renewal (Ngapara Switchgear)		462								
Asset Replacement & Renewal (Pukeuri Alliance Switchgear)			200	500	200					
Asset Replacement & Renewal (Other)	618	525	474	474	520	432	432	478	432	432
Total	1,152	2,339	1,549	1,284	1,130	1,192	957	1,238	957	1,192

5.7 Sub-Transmission Network

5.7.1 Overview of the sub-transmission network

The sub-transmission network connects the supply of electricity from Transpower grid exit points (GXPs) to our zone substations. The zone substations connect to our distribution network to supply the local community.

Supplies to zone substations are generally configured so they have an alternative supply from another sub-transmission circuit. This also makes the sub-transmission assets relatively easy to remove from service in order to carry out inspections, maintenance and repairs.

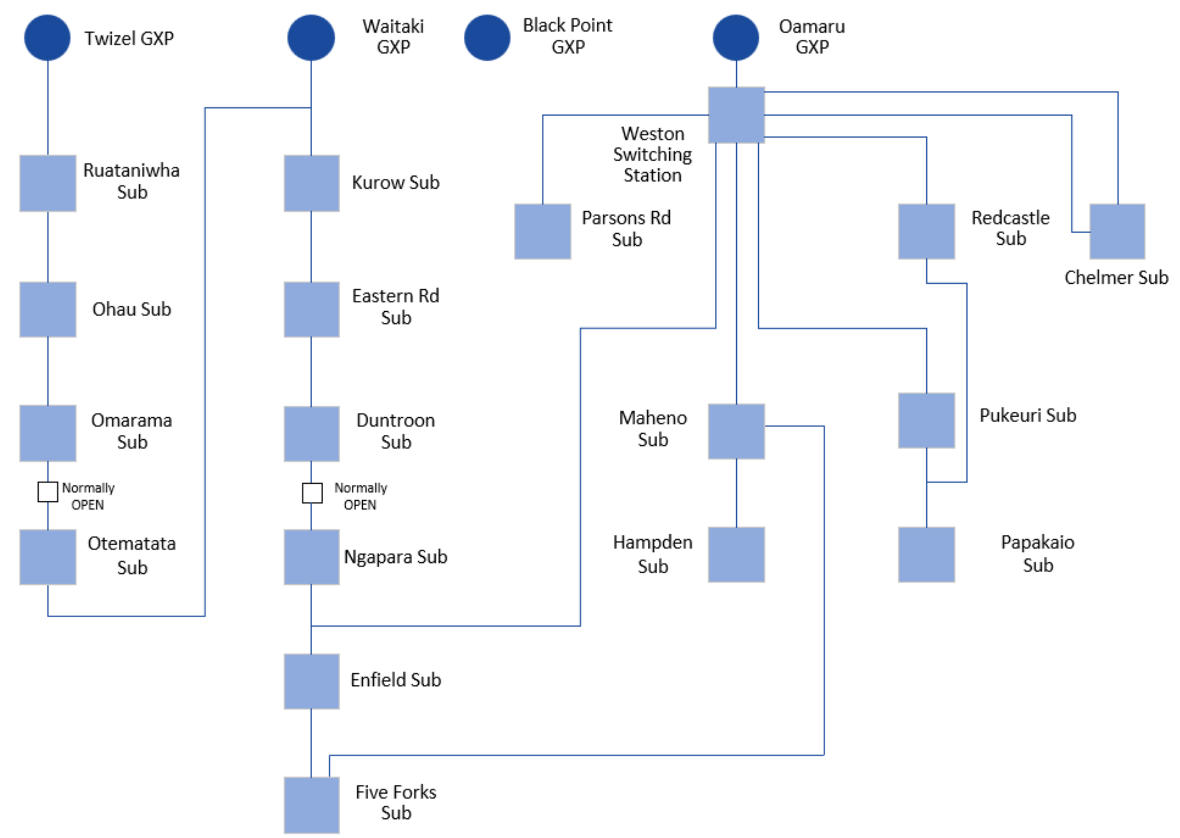


Figure 35 - Sub-transmission system configuration

5.7.2 Management approach

The 33 kV sub-transmission network is mostly overhead construction, apart from some short lengths of cable, generally between the feeder CBs and line terminations, and on the Redcastle to Pukeuri feeder.

Our objectives for the maintenance of our sub-transmission assets are to:

- Keep members of the public safe.
- Maintain the reliable supply of electricity to our zone substations and minimise supply interruptions.

A failure on the sub-transmission system can affect several zone substations, and hence many customers. The construction maintenance and inspection requirements for these high criticality assets is accordingly to a higher standard than the general distribution system.

5.7.3 Sub-transmission lines

Our sub-transmission overhead circuits total 231km in length and are a mixture of ACSR, AAC and AAAC conductors.

ACSR is a stranded aluminium conductor reinforced with steel strands at its core. This conductor is chosen for its high strength and reasonable conductivity. It performs well under snow, wind and ice environments but can be vulnerable to corrosion in coastal and other areas with high air pollution.

AAC is a stranded All Aluminium Conductor. This conductor has been historically chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability, as the spans between poles are shorter.

AAAC is a stranded All Aluminium Alloy Conductor. This conductor has good conductivity and corrosion resistance and better strength characteristics than AAC, though not quite as good as ACSR. It performs well in all environments and is the default conductor of choice on the sub-transmission network unless the local conditions (e.g. higher altitude) require the use of ACSR.

A summary of the line conductor types on our sub-transmission system is in the table below.

Table 24 - summary of sub-transmission line types

Conductor type	Length
ACSR	84 km
AAC	77 km
AAAC	70 km

5.7.3.1 Age and health profile data

The average life expectancy we apply to our sub-transmission lines is 60 years and an age profile for them is shown below:

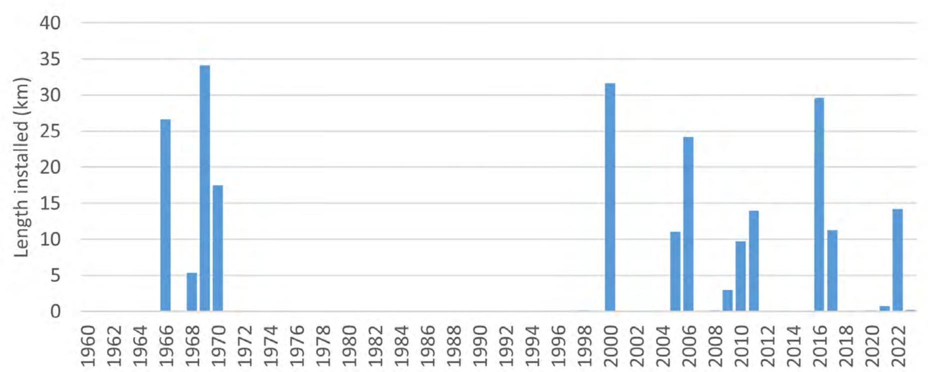


Figure 36 - Asset Age profile of sub-transmission over head conductor

The health profile of these assets is shown below. Sub-transmission lines are often installed and replaced in large sections with the same material subject to similar environmental conditions. This is reflected in the "stepped" nature of the profile.

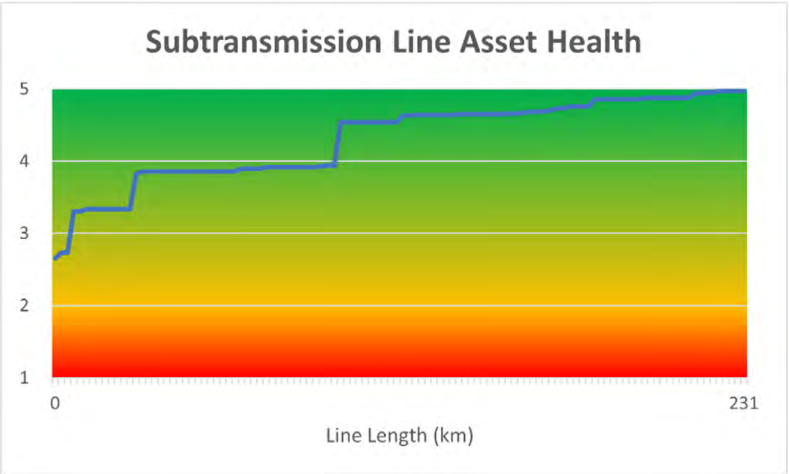


Figure 37 – Asset Health profile of sub-transmission over head conductor

5.7.3.2 Asset risks

Major risks to the sub-transmission lines include:

- Extreme weather events such as heavy snow or high winds resulting in contact with trees or windborne debris
- External equipment – pivot irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Thermal fatigue or damage to connections due to cyclic loading or through fault currents.

5.7.3.3 Inspection and maintenance programme

Table 25 - Sub-transmission lines inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003	Annual
Vegetation Patrols	Overhead sub-transmission lines are inspected annually by our specialist vegetation team to maintain safety and reliability	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	5 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

5.7.3.4 Renewal and refurbishment programme

Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild. Some sub-transmission circuits that were installed in the 1960s are scheduled for rebuilding during the planning period. In the planning period we expect to rebuild the Weston to Maheno 33kV circuit due to conductor condition caused by vibration over time. Replacement of conductor on Weston to Chelmer No.1 33 kV is budgeted for FY24, based on the age of the existing conductor, and the criticality of the asset. In a similar vein, the 33 kV conductor between Omarama and Twizel will be beyond its standard life expectancy during the planning period, and is known to have suffered damage due to extreme weather events, including effects of historic heavy snow loads, although is not yet showing end of life characteristics.

During renewals we may also improve the reliability of the sub-transmission network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so.

5.7.4 Sub-transmission support structures

Sub-transmission lines are supported by 2506 poles. They are a mixture of wooden (Hardwood and Softwood) and concrete (Pre-stressed and Mass Reinforced).

Hardwood poles are usually sourced from Australia. They are suitable in all conditions and can be used under all loading conditions.

Softwood poles are usually locally sourced. They are suitable in all conditions and can be used under all loading conditions but have a lower strength to size ratio compared with hardwood poles and they age faster.

Pre-stressed poles are usually locally sourced. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations. They are lighter than wood and mass reinforced concrete poles for a given strength but are vulnerable to shock loads such as from contact machinery and vehicles.

Mass reinforced poles were usually locally sourced but are no longer available. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations, but they are less vulnerable to shock loads than prestressed poles.

A summary of the different pole types in use on the sub-transmission system is in the table below.

Table 26 – Pole types in use on the sub-transmission system

Asset type	Number
Hardwood Poles	1560
Softwood Poles	482
Pre-stressed Concrete	227
Mass Reinforced Concrete	237

5.7.4.1 Age and health profile data

The average life expectancy we apply to our poles is 40 years for softwood poles and 60 years for all other types. An age profile for them is shown below. Softwood poles have been installed on sub-transmission lines only since 2000.

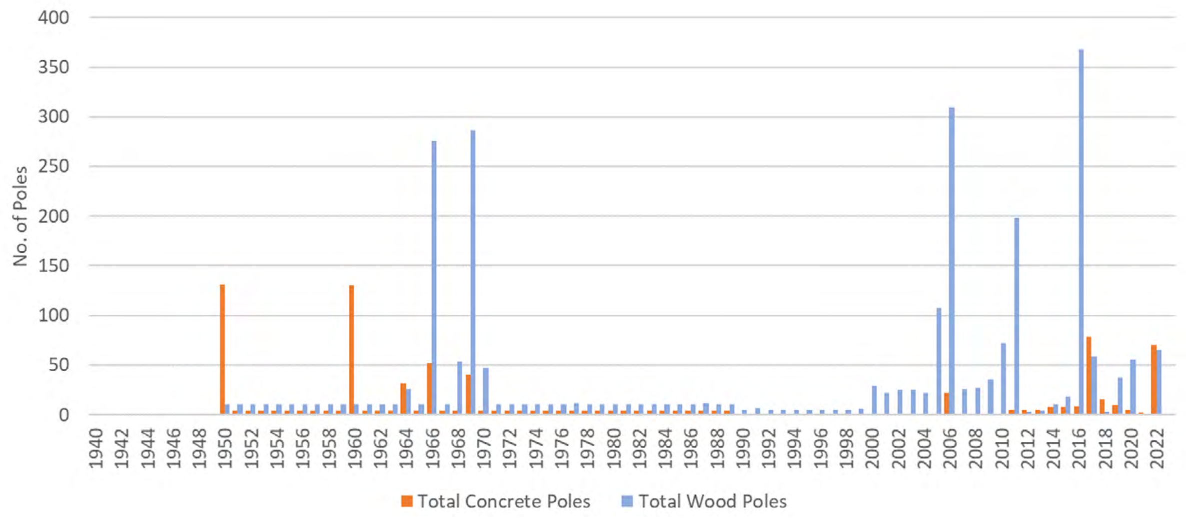


Figure 38 - Age profile for sub-transmission poles

Concrete and wood poles have different condition assessment criteria but are graded using a common index. The asset health of the concrete and wood pole fleets are shown below.

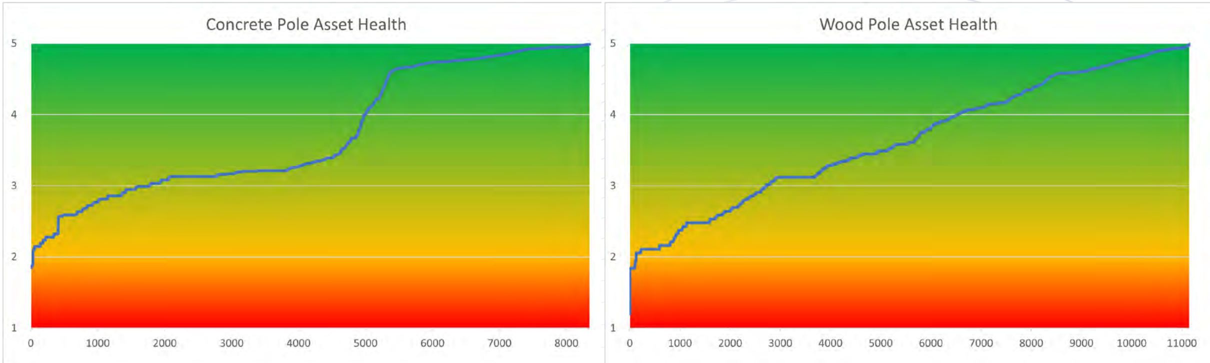


Figure 39 - Asset health of concrete and wood pole fleets

5.7.4.2 Asset risks

Major risks to the sub-transmission poles include:

- Vehicle impact – much of the network is built adjacent to public roads
- Erosion of land around foundations
- Extreme weather events such as high winds or heavy snow
- Degradation of structural strength due to age related issues such as pole decay.

5.7.4.3 Inspection and maintenance programme

Table 27 - Sub-transmission support structures inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware. Testing of pole structural condition using Thor hammer and Portascan test sets, digging and probing. Thermal inspection of joints and cable terminations. Vegetation related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	Annual
Vegetation Patrols	Overhead sub-transmission lines are inspected annually by our specialist vegetation team to maintain safety and reliability.	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	Annual
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

5.7.4.4 Renewal and refurbishment programme

Renewals in the sub-transmission network are largely repairs and replacements to structures based on the results of line patrols. Individual poles are generally earmarked for removal due to condition and changed in a suitable shutdown period. The renewal budget for pole and hardware replacement is based on defect rates developed from recent analysis of line patrols.

Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild. Some sub-transmission circuits that were installed in the 1960s are forecast for such rebuilding during the planning period. In the planning period we expect to rebuild the Weston to Maheno 33kV circuit due to conductor condition caused by age and vibration. Replacement of conductor on Weston to Chelmer No.1 33 kV is budgeted for FY24, based on the age of the existing conductor, and the criticality of the asset, an in a similar vein the 33 kV conductor between Omarama and Twizel will be beyond its standard life expectancy during the planning period, and is known to have suffered damage due to heavy weather, including effects of historic heavy snow loads, although is not yet showing end of life characteristics.

During renewals we may also improve the reliability of the sub-transmission network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so. Condition based pole replacements that are required on the Chelmer St substation No.2 33 kV circuit are in difficult to reach locations, and the opportunity is being taken to replace the affected section of line with a new cable, at the same time locating in a more diverse route from the other 33 kV feeder. This will increase the resilience of the substation.

5.7.5 Sub-transmission cables

We have a small length (4km) of underground cable on our sub-transmission network, all of it modern (post 1985) XLPE type.

XLPE (Cross Linked Polyethylene) enhances the temperature properties of the insulation, allowing strength and chemical stability to be maintained at higher operating temperatures (and loads). Impact and tensile strength, scratch resistance, and resistance to brittle fracture are also enhanced over other insulation types.

5.7.5.1 Age and health profile data

The average life expectancy we apply to our modern XLPE cables is 55 years. An age profile for the various sections is shown below:

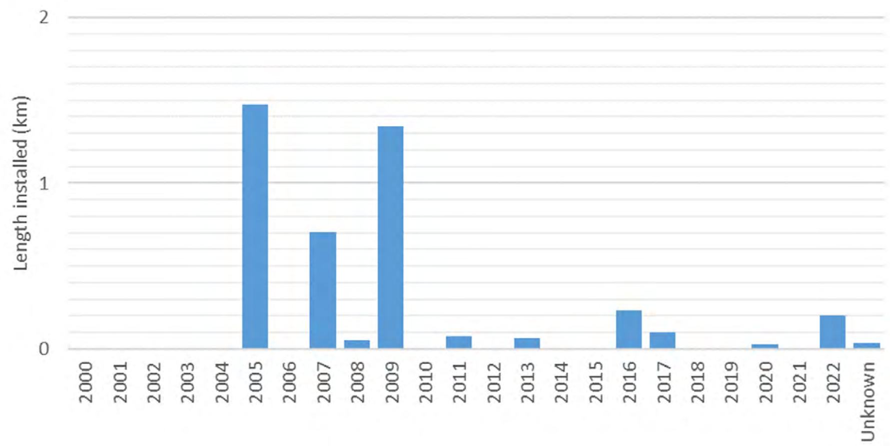


Figure 40 - Age profile of sub-transmission underground cables

5.7.5.2 Asset risks

- Major risks to the sub-transmission cables include:
- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation.

5.7.5.3 Inspection and maintenance programme

Table 28 - Sub-transmission cables inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Patrol of cable routes to identify land damage and any excavation work in the vicinity	Annual
Partial Discharge Monitoring	Sub-transmission cable terminations as part of zone substation partial discharge monitoring	Annual

5.7.5.4 Renewal and refurbishment programme

Given the asset type, age and condition, there are no renewal or refurbishment plans for Network Waitaki's sub-transmission cables within the planning period.

5.7.6 Sub-transmission switchgear

Sub-transmission switchgear is used to control and redirect the flow of electricity between our various zone substations. They are differentiated by function into subcategories (Circuit Breakers, Reclosers, Sectionalisers and Isolators).

Circuit Breakers are designed to operate and safely interrupt supply even under fault conditions where there are significant amounts of energy to be contained. They are normally located within zone substations.

Reclosers perform a similar function to Circuit Breakers but are usually rated to lower energy levels. Reclosers will automatically restore supply (re-close) in a transient fault situation. Often the only difference between a Circuit Breaker and a Recloser is its control mechanism and operational configuration.

Sectionalisers are used to isolate (sometimes automatically) sections of the network and can be operated under load, but not when a fault current is present.

Isolators (Air Break Switches) are like Sectionalisers but can only be operated when there is no load flowing through them.

We utilise Vacuum and SF6 insulated switchgear Circuit Breakers, Reclosers and Sectionalisers in our sub-transmission network. Isolators are air insulated. Most of this equipment is of recent manufacture, although there are a handful of older items.

5.7.6.1 Age and health profile data

The average life expectancy we apply to our sub-transmission switchgear is 45 years and age profiles for the various types are shown below.

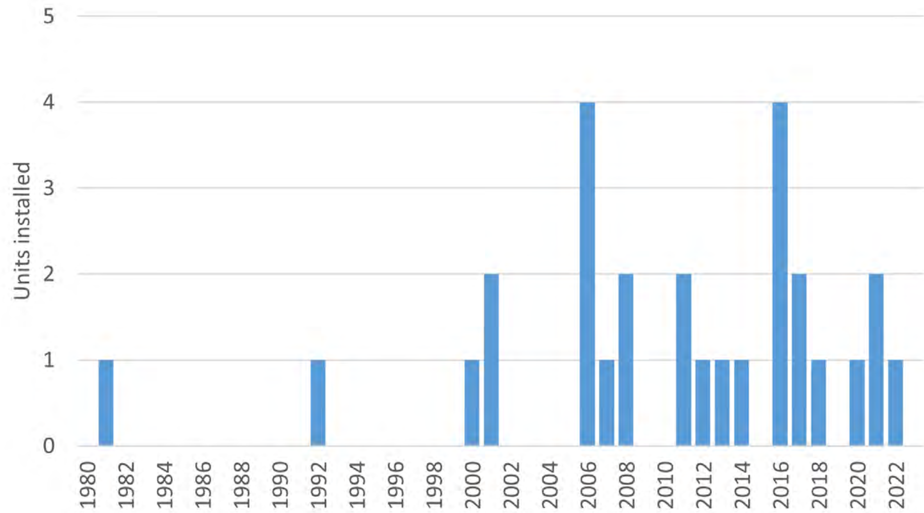


Figure 41 – Age profile of sub-transmission circuit breakers

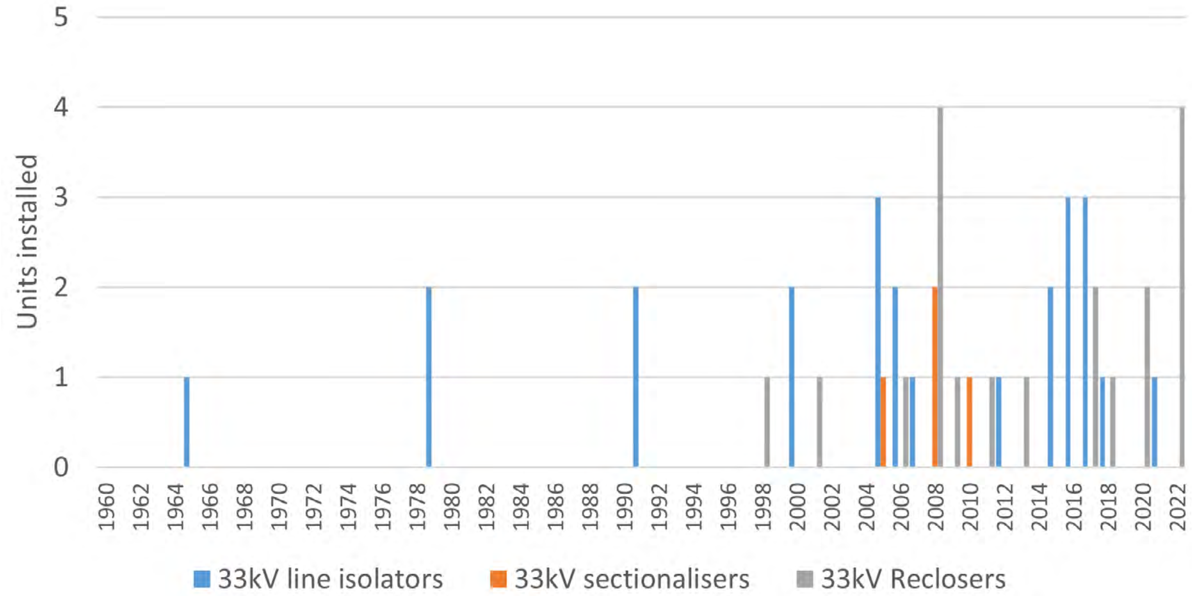


Figure 42 – Age profile of other sub-transmission switchgear

The practicable life of Circuit Breakers and Reclosers is often determined by other factors such as operational functional requirements, number of operations and magnitude of fault interruption. Asset Condition is therefore a more accurate indicator of remaining life than age.

The asset health of 33kV Circuit Breakers (including Reclosers), Sectionalisers and Isolators are shown below.

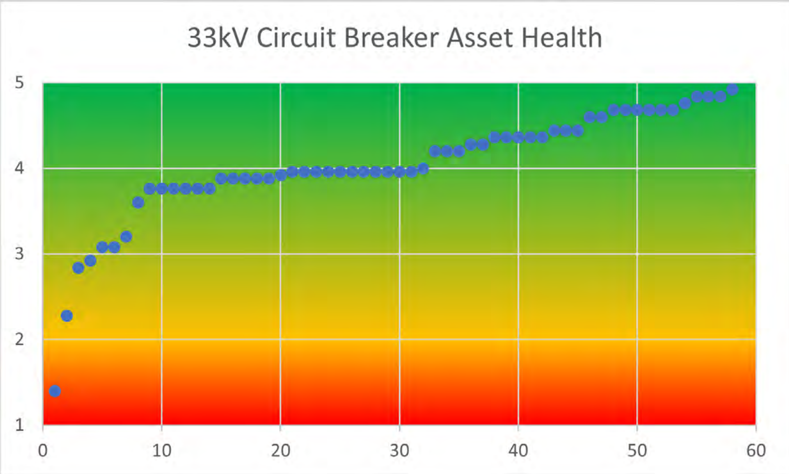


Figure 43 – Asset Health profile of sub-transmission Circuit Breakers and Reclosers

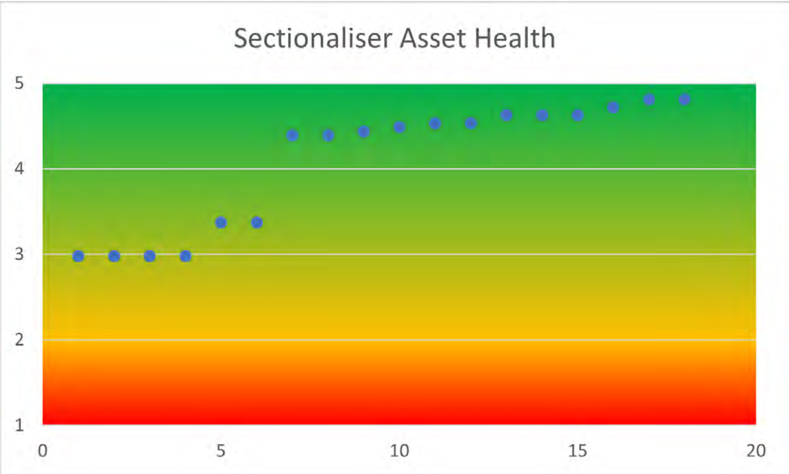


Figure 44 – Asset Health profile of sub-transmission Sectionalisers

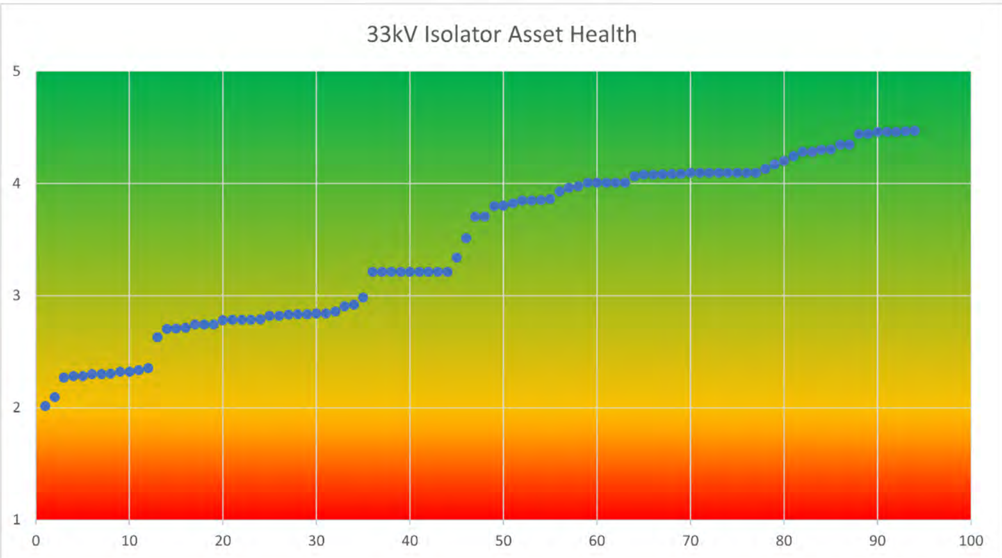


Figure 45 – Asset Health profile of sub-transmission Isolators

5.7.6.2 Asset risks

Risks commonly associated with our sub-transmission switchgear include:

- Loss of insulating gas or vacuum
- Failure of porcelain insulator through cracking or age
- Failure due to terminations overheating.

5.7.6.3 Inspection and maintenance programme

Table 29 - Sub-transmission switchgear inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Thermal inspection of switchgear and terminations	Annual
Climbing patrol	Physical check of terminations, fittings etc.	5 yearly
Operational checks	Verification of settings and trip testing. Battery replacement	5 yearly

5.7.6.4 Renewal and refurbishment programme

Switchgear in this category is replaced based on condition assessment or as they become obsolete, and the management of spares becomes problematic. We expect to replace two reclosers in this planning period for these reasons.

There is a known problem with a particular brand of 33 kV air break switch where the porcelain insulators crack and fail. We will be replacing all examples of this type of ABS in the early years of the planning period.

5.7.7 Total Sub-transmission network maintenance and renewal expenditure

Table 30 - Total sub-transmission network maintenance and renewal expenditure

Sub-transmission ($000)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Service Interruptions & Emergencies	11	12	15	15	15	15	15	15	15	15
Routine & Corrective Maintenance and Inspections	193	287	249	192	192	192	192	192	192	192
Asset Replacement & Renewal (Weston-Maheno)		390	274	274						
Asset Replacement & Renewal (Chelmer St 2)	57	360								
Asset Replacement & Renewal (Omarama-Twizel)					296	240	240			
Asset Replacement & Renewal (Other)	242	382	314	314	314	314	314	314	314	314
Asset Relocations	36									
Total	539	1,431	852	795	817	761	761	521	521	521

5.8 Distribution Network

5.8.1 Overview of the distribution network

Our distribution network operates at 11 kV. The distribution network reaches out from our zone substations to supply the majority of our customers using distribution transformers to convert the 11 kV supply down to 400/230 V for connection to customer loads.

There are fifty-five 11 kV distribution feeder lines supplied from our 33/11 kV zone substations. Supply restoration in the event of an outage is often possible by connecting neighbouring feeders. To further assist in quicker supply restoration, we have embarked on a programme of installing automated open points on 11 kV interconnection between substations.

There are 1,255 km of overhead lines and 81 km of 11 kV cables on our distribution network.

5.8.2 Management approach

We maintain our distribution network with the aims of keeping it safe for our workers and the public, and minimising outages. Our approach is mainly driven from defects found during regular inspection cycles, or generated from other work such as customer connections, or attendance at faults. When a part of the network is particularly affected by a major event (e.g., a snowstorm) we will instigate a special line patrol post event.

Where 11 kV feeders interconnect, they are normally configured as open points using remote controlled switches. This provides the ability to swiftly reconfigure the network to support load in the event of an outage. NWL's loadings are such that security provisions are generally focussed on switching to restore supply quickly rather than targeting zero interruptions.

This approach, which is backed by a fairly well interconnected distribution network, means that outage figures are kept below our targets without over investment on the distribution network.

Our distribution network covers a large area, with many assets in diverse locations, ranging from busy urban streets to isolated mountainsides. Individual components connect fewer and fewer customers the closer they are to the load, down to the level of an individual installation. Accordingly, we aim to balance our maintenance and renewals with the risk and service level associated with each asset.

Key objectives for management of our distribution network include

- keeping the public safe
- keeping our workers safe
- maintaining the reliability of our network
- no unassisted failures of poles and conductors in normal operating conditions
- reduce the number of third-party contact incidents on our distribution network
- no incidents of unauthorised access to our ground mounted distribution assets
- maintain the visual condition of our assets in neighbourhood areas.

5.8.3 Distribution lines

Our distribution lines connect the zone substation to distribution transformers, which are usually next to public roads or within the property they service. Any failures can be disruptive to our customers and the public at large as most of the equipment is located in publicly accessible areas. They operate at 11kV and total 1260km in length and are a mixture of HD Cu, GS, ACSR, AAC and AAAC conductors.

HD Cu is a stranded Copper conductor specifically treated to ensure it retains its shape over time. It performs well under all environmental conditions and has excellent electrical properties. The cost increases in the late 1960s mean that it is now rarely used in new builds.

GS (Galvanised Steel) has been used in areas where mechanical strength needs dominate over electrical requirements. This conductor has extremely high strength but poor reasonable conductivity. It performs well under snow, wind and ice environments but can be vulnerable to corrosion in coastal and other areas with high air pollution.

ACSR is a stranded Aluminium conductor reinforced with steel strands at its core. This conductor is chosen for its high strength and reasonable conductivity. It performs well under snow, wind and ice environments but can be vulnerable to corrosion in coastal and other areas with high air pollution.

AAC is a stranded All Aluminium Conductor. This conductor has been historically chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability as the spans between poles are shorter.

AAAC is a stranded All Aluminium Alloy Conductor. This conductor has good conductivity and corrosion resistance and better strength characteristics than AAC though not quite as good as ACSR. It performs well in all environments and is the default conductor of choice on the sub-transmission network unless the local conditions (e.g., higher altitude) require the use of ACSR.

A summary of the line conductor types on our 11kV distributions system is in the table below.

Table 31 - Summary of distribution line types

Conductor type	Length
HD Cu	99 km
GS	80 km
ACSR	919 km
AAC	109 km
AAAC	38 km
Unknown	15 km

5.8.3.1 Age and health profile data

The average life expectancy we apply to our distribution lines is 55 years and an age profile for them is shown below.

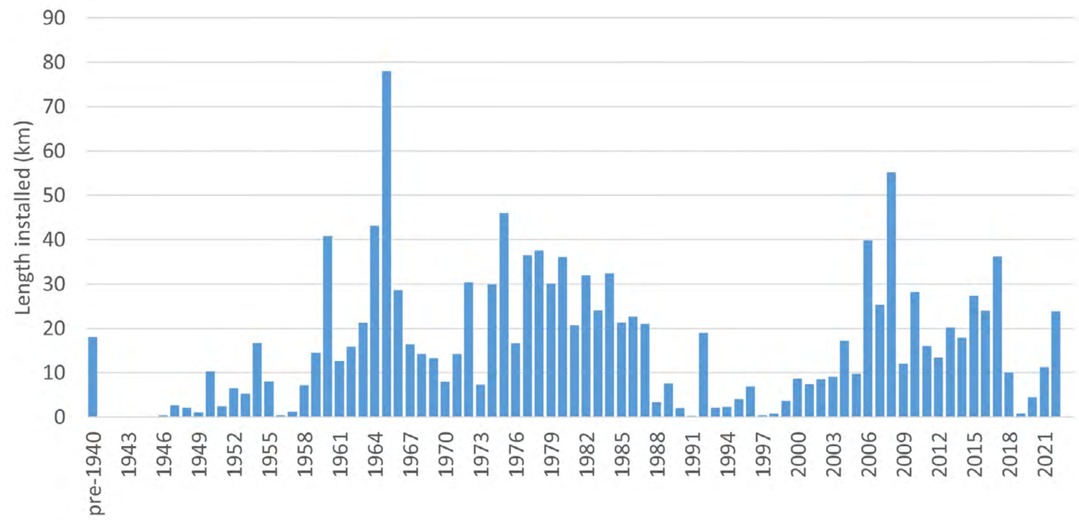


Figure 46 - Health profile of 11 kV overhead lines

The asset health profile of these assets is shown below.

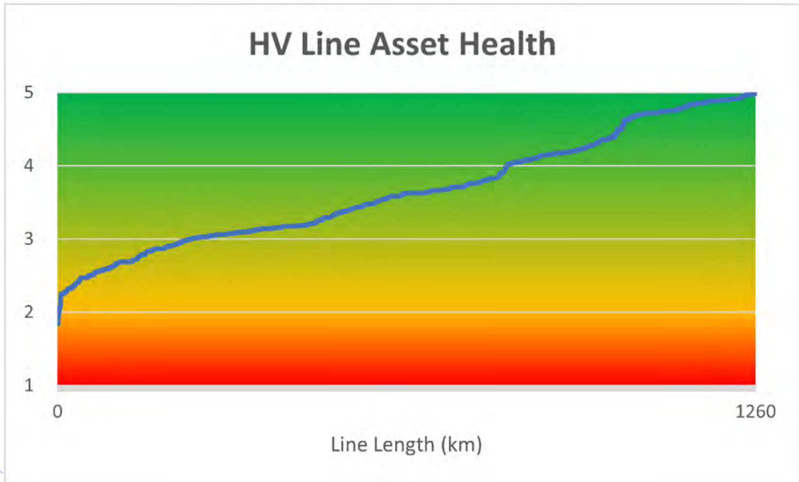


Figure 47 - Health profile of 11 kV overhead lines

5.8.3.2 Asset risks

Major risks to the distribution lines include:

- Extreme weather events such as heavy snow or high winds resulting in contact with trees or windborne debris
- External equipment – pivot irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Thermal fatigue or damage to connections due to cyclic loading or through fault currents.

5.8.3.3 Inspection and maintenance programme

Table 32 - Distribution lines inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	5 yearly
Vegetation Patrols	Overhead lines on main feeder routes are inspected annually by our specialist vegetation team to maintain safety and reliability.	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	15 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines.	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

5.8.3.4 Renewal and refurbishment programme

Conductor replacements are primarily determined with condition as the highest weighted factor, followed by maintainability and age if required. Sometimes localised load increases will mean that a conductor is replaced for capacity or voltage support reasons before it reaches the end of its practical life. In that case the replacement will be included in the Network Development programme (Section 6). Using Asset Health modelling, the conductor fleet will be replaced using the following priorities:

- All single wire steel conductors will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2024-2028).
- All other steel wired conductors that are within the enmeshed network or supplying more than two transformers on a radial branch will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2024-2028).
- All other steel wired conductors that supply two or fewer transformers on a radial branch will be replaced in the year following their scheduled inspections in FYE 2028-2032.
- All 7/.064 Copper conductors that are within the enmeshed network or supplying more than two transformers on a radial branch will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2024-2028).
- All 7/.064 Copper wired conductors that supply two or fewer transformers on a radial branch and any remaining 7 stranded Copper Conductors will be replaced in the year following their scheduled inspections in FYE 2029-2033.

This will result in the removal of all Steel conductors from the network by 2032 and the replacement of all 7 stranded Copper conductors on the network by 2034.

5.8.4 LV lines

Our LV lines connect distribution transformers which are usually next to public roads along the local street to customers' properties. They operate at 400V,total 222km in length and are a mixture of bare and covered HD Cu and, AAC conductors.

HD Cu is a stranded Copper conductor specifically treated to ensure it retains its shape over time. It performs well under all environmental conditions and has excellent electrical properties. The cost increases in the late 1960s mean that it is now rarely used in new builds.

AAC is a stranded All Aluminium Conductor. This conductor has been historically chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability as the spans between poles are shorter.

A summary of the line conductor types on our LV system is in the table below.

Table 33 - Summary of LV line types

Conductor type	Length
HD Cu	34 km
AAC	26 km
Unknown	162 km

5.8.4.1 Age profiles and population data

The average life expectancy we apply to our LV lines is 55 years and an age profile for them is shown below.

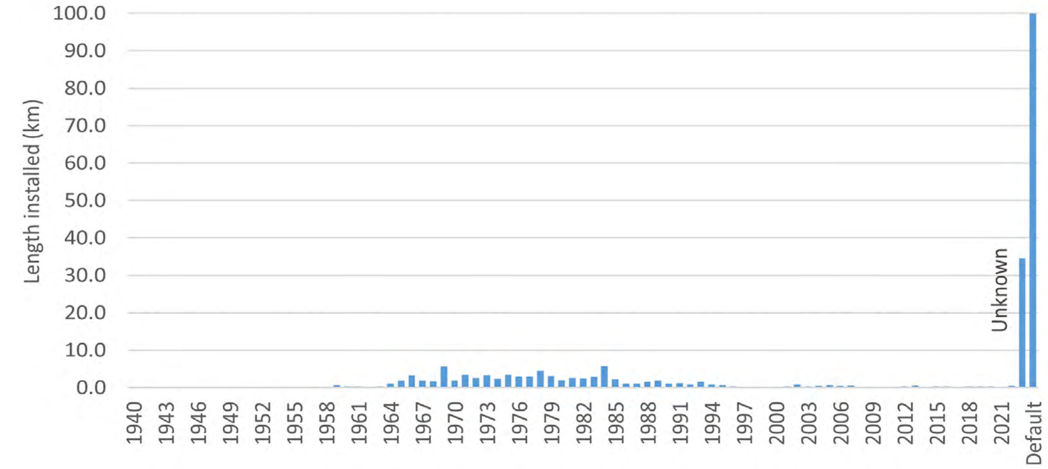


Figure 48 - Age profile of LV lines

The asset health profile of these assets is shown in the following chart:

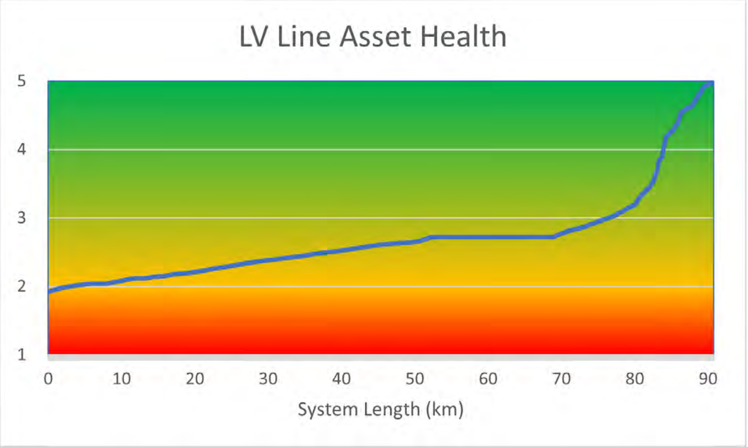


Figure 49 - Health profile of LV overhead lines

5.8.4.2 Asset risks

Major risks to the LV lines include:

- Extreme weather events such as heavy snow or high winds resulting in contact with trees or windborne debris
- External equipment – farming equipment and irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Insufficient clearance above ground or between the conductors and structures.

5.8.4.3 Inspection and maintenance programme

Table 34 - LV lines inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	5 yearly
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	5 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines.	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

5.8.4.4 Renewal and refurbishment programme

Conductor replacements are primarily determined with condition as the highest weighted factor, followed by maintainability and age if required. Sometimes localised load increases will mean that a conductor is replaced for capacity or voltage support reasons before it reaches the end of its practical life. In that case the replacement will be included in the Network Development Programme (Section 6). There are no type issues with this asset class so replacement will continue to be based on condition or load requirements only.

5.8.5 Distribution support structures

Distribution lines are supported by 17,339 poles of which 2889 support LV lines only with the balance supporting 11kV lines or a combination of both voltages. They are a mixture of wooden (Hardwood and Softwood) and concrete (Pre-stressed and Mass Reinforced). Some distribution lines are co-located on poles owned by other asset owners. There are about 2000 poles supporting HV Distribution Lines that supply customers on private property. Network Waitaki will be engaging with the property owners and end customers to agree to a solution for the ongoing management of these lines and supports in the long term.

Hardwood poles are usually sourced from Australia. They are suitable in all conditions and can be used under all loading conditions.

Softwood poles are usually locally sourced. They are suitable in all conditions and can be used under all loading conditions but have a lower strength to size ratio compared with hardwood poles and age faster.

Pre-stressed poles are usually locally sourced. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations. They are lighter than wood and mass reinforced concrete poles for a given strength but are vulnerable to shock loads such as from contact machinery and vehicles.

Mass reinforced poles were usually locally sourced but are no longer available. They are suitable in most conditions but are vulnerable in low temperatures and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations, but they are less vulnerable to shock loads than pre-stressed poles.

A summary of the different pole types in use on the distribution system is in the table below.

Table 35 - Pole types in use on the distribution system

Asset type	All Distribution	LV Only
Hardwood Poles	6,923	1,285
Softwood Poles	2,394	393
Pre-stressed Concrete	1,074	229
Mass Reinforced Concrete	6,948	982

5.8.5.1 Age profiles and population data

The average life expectancy we apply to our poles is 40 years for softwood poles and 60 years for all other types. An age profile for them is shown below.

Of the nearly 22,000 poles on our network, about 40% are of unknown or uncertain age. Data collection using the new field collection platform will provide estimated ages as part of the inspection process, supported by condition data for each pole. This should close this age information gap within five years.

For this reason, we have been enhancing our inspection techniques, to ensure that our condition-based replacement regime is not degraded by the unknown age data.

Any probable installation dates that are developed during this exercise will also be verified against the details of nearby assets using our GIS systems. In this way, we expect to improve our confidence in the age profile of our network poles.

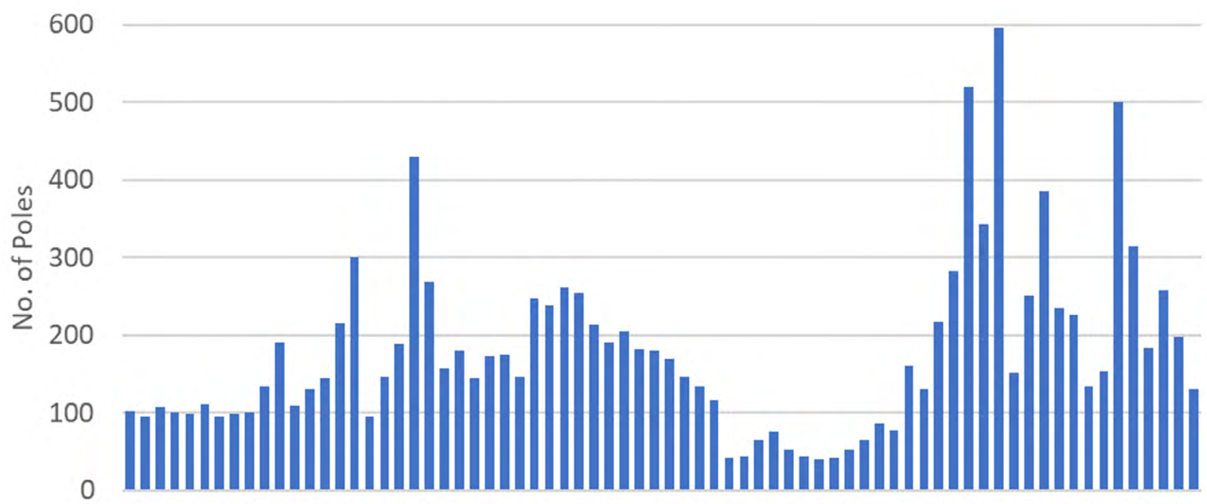


Figure 50 - Age profile of wooden poles

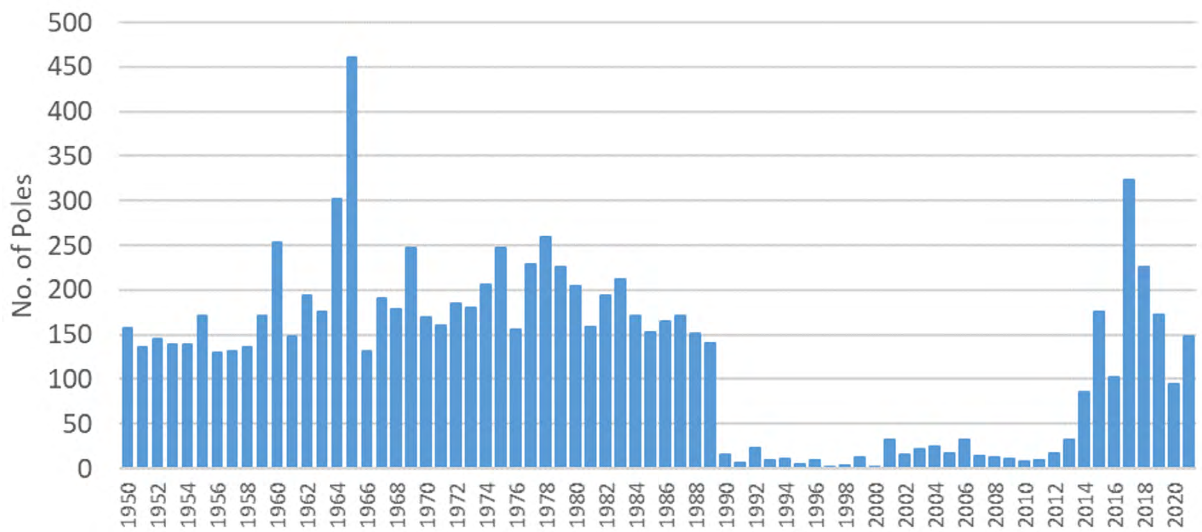


Figure 51 - Age profile of concrete poles

Concrete and wood poles have different condition assessment criteria but are graded using a common index. The asset health of the distribution poles by type are shown below.

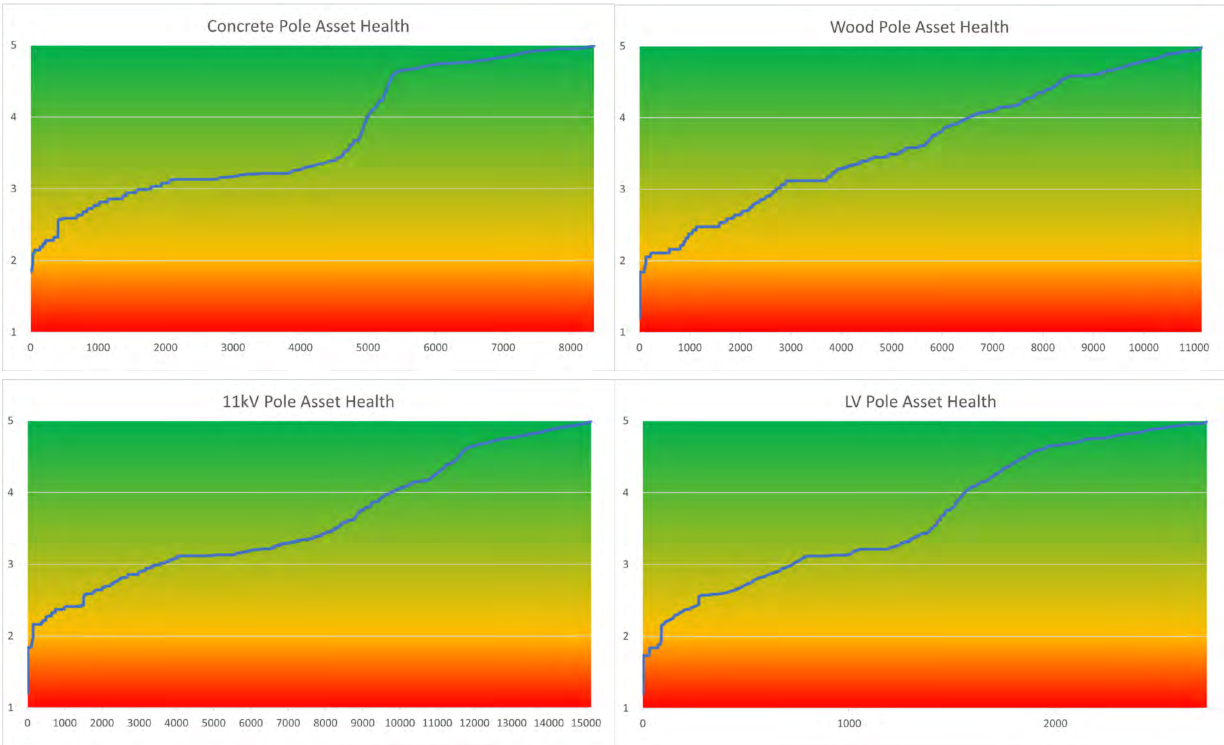


Figure 52 – Asset Health profiles for distribution poles

5.8.5.2 Asset risks

Major risks to the distribution poles include

- vehicle impact – much of the network is built adjacent to public roads
- erosion of land around foundations
- extreme weather events such as high winds or heavy snow
- degradation of structural strength due to age-related issues such as pole decay.

Applying criticality factors with our Asset Health indices can then identify the total risk associated with each structure. Likelihood of Failure correlates with Asset Health and Consequence of Failure correlates with Asset Criticality.

A categorised summary aligning with EEA Guidelines using these risk values is shown below.

	AHI					
ACI	H5	H4	H3	H2	H1	Ungraded
C4	0	0	0	0	0	0
C3	3977	2300	5545	82	69	3934
C2	502	359	1099	17	9	906
C1	998	339	1008	12	3	538
	5477	2998	7652	111	81	5378

Figure 53 - Health and Criticality of poles

5.8.5.3 Inspection and maintenance programme

Table 36 - Distribution support structures inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware. Testing of pole structural condition using Thor hammer and Portascan test sets, digging and probing. Thermal inspection of joints and cable terminations. Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	Annual
Vegetation Patrols	Overhead sub-transmission lines are inspected annually by our specialist vegetation team to maintain safety and reliability.	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	Annual
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

5.8.5.4 Renewal and refurbishment programme

Renewals in the distribution network are largely repairs and replacements to structures based on the results of line patrols. Individual poles are generally earmarked for removal due to condition and changed in a suitable shutdown period. The renewal budget for pole and hardware replacement is based on defect rates developed from recent analysis of line patrols. Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild.

During renewals we may also improve the reliability of the network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so.

5.8.6 Distribution cables

Distribution cables perform the same function as distribution lines in that they connect the zone substation to distribution transformers. They are usually along public roads or within the property they service and are mainly installed in urban areas. Any failures can be disruptive to our customers and the public at large as most of the equipment is in publicly accessible areas. They operate at 11kV and total 89 km in length and are a mixture of Copper and Aluminium conductors insulated with PILC or XLPE.

PILC – Paper Insulated Lead Covered cables are manufactured by using layers of paper impregnated with a compound mineral oil as insulating medium, both as individual core and overall insulation. They are a long lasting and proven technology with some cables remaining in service for over 100 years. They offer less flexibility during installation and usually allow a lower load rating for any given size than XLPE as they have a lower maximum operating temperature. Jointing and connecting them usually requires a higher skillset.

XLPE (Cross Linked Polyethylene) enhances the temperature properties of the insulation allowing strength and chemical stability to be maintained at higher operating temperatures (and loads). Impact and tensile strength, scratch resistance, and resistance to brittle fracture are also enhanced over other insulation types. Early production (pre-1985) XLPE cables were found to be vulnerable to "treeing", which results in accelerated breakdown of the insulation.

A summary of the cable types on our 11kV distribution system is in the table below.

Table 37 - Summary of 11kV distribution cable types

Conductor type	Length
Cu PILC	9 km
Cu XLPE	1 km
Al PILC	12 km
Al XLPE	63 km
Unknown	4 km

5.8.6.1 Age profiles and population data

The average life expectancy we apply to PILC cables is 70 years, modern XLPE cables is 55 years while first generation XLPE is 45 years. An age profile for the various sections is shown below.

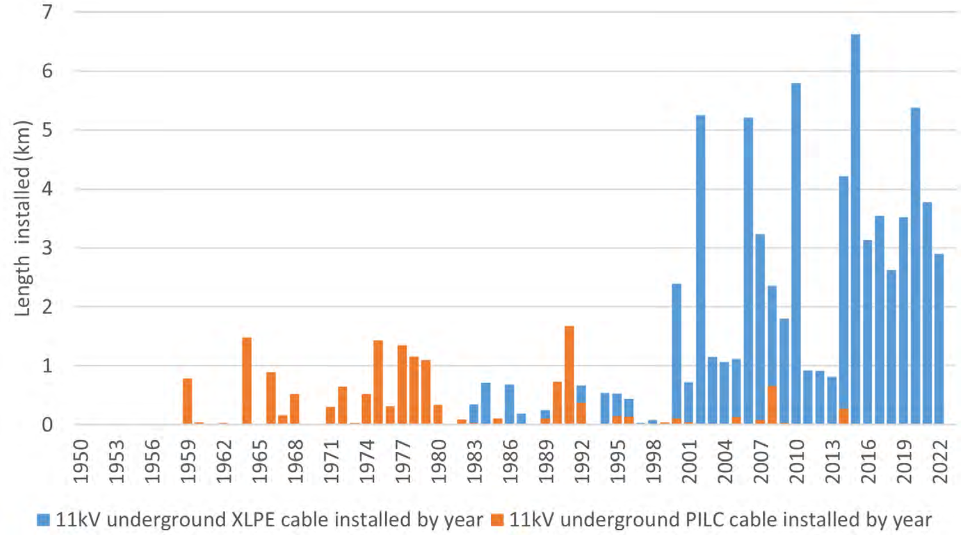


Figure 54 - Age profile of 11 kV cables

The asset health profile of these assets is shown below.

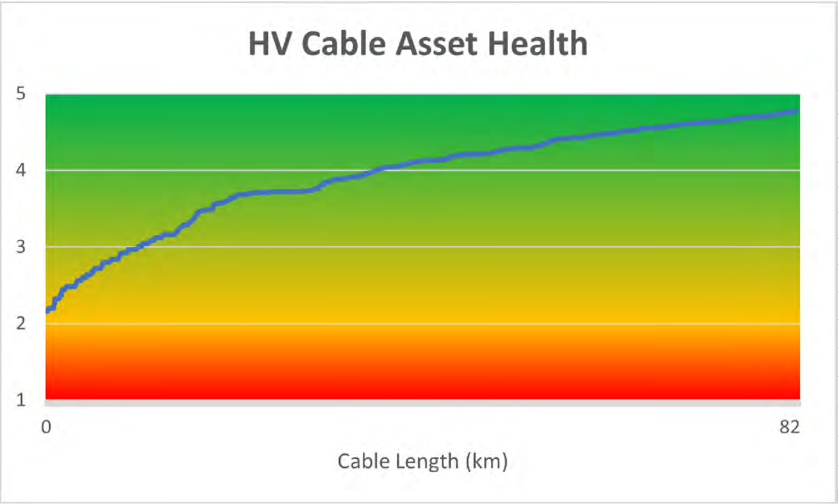


Figure 55 - Health profile of 11 kV cables

5.8.6.2 Asset risks

Major risks to the distribution cables include:

- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation
- Sudden failure of pitch filled terminations

5.8.6.3 Inspection and maintenance programme

Table 38 - Distribution cables inspection and maintenance programme

Activity	Summary	Frequency
Partial Discharge Monitoring	Distribution cable terminations as part of substation partial discharge monitoring	Annual

5.8.6.4 Renewal and refurbishment programme

Given the asset type, age and condition, there are no renewal or refurbishment plans for Network Waitaki's distribution cables within the planning period unless they are part of a greater project.

The 29 remaining outdoor pitch-filled terminations are scheduled for replacement during the planning period.

5.8.7 LV cables

Our LV cables connect distribution transformers which are usually next to public roads and along local streets to customers' properties. They operate at 400V, total 88km in length and are a mix of Copper and Aluminium conductors predominantly within urban areas.

A summary of the cable types on our LV system is in the table below.

Table 39 - Summary of LV line types

Conductor type	Length
Copper	21 km
Aluminium	39 km
Unknown	28 km

Copper cables are generally used to supply smaller groups of customers (fewer than 10) and are usually installed in short sections along accessways or across roads.

Aluminium cables are used for the main sections of the 400V distribution network and are usually along public roads, along the frontage of the properties they service.

5.8.7.1 Age profiles and population data

The average life expectancy we apply to LV cables is 70 years. An age profile for the various sections is shown below.

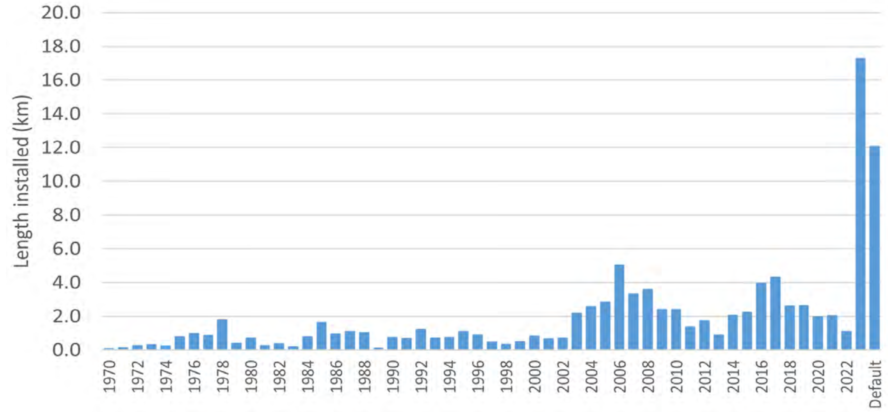


Figure 56 - Age profile of LV cables

The asset health profile of these assets is shown below.

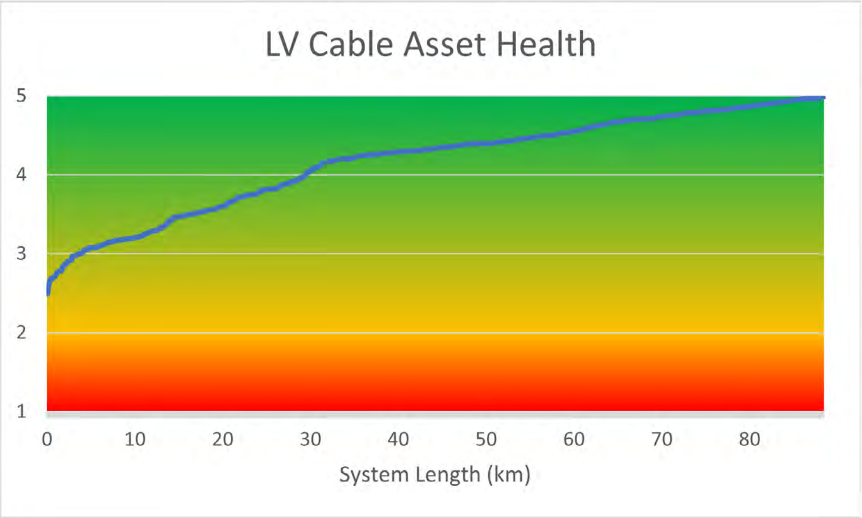


Figure 57 - Health profile of LV Cables

5.8.7.2 Asset risks

Major risks to the LV cables include:

- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation
- Overheating of joints and terminations

5.8.7.3 Inspection and maintenance programme

Table 40 - LV cables inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for any damage, such as broken strands Thermal inspection of joints and terminations Part of the Distribution transformer inspection programme	Annual
Partial Discharge Monitoring	Distribution cable terminations as part of distribution substation partial discharge monitoring	Annual

5.8.7.4 Renewal and refurbishment programme

Given the asset type, age, and condition, there are no renewal or refurbishment plans for Network Waitaki's distribution cables within the planning period unless they are part of a greater project.

5.8.8 Distribution cable enclosures

We have 2725 distribution cable enclosures that allow staff access to key parts of the cabling system including fusing and isolation points while preventing the public from accessing energised network equipment. They are differentiated by purpose with, 1.) Distribution Cabinets that house network switching equipment and isolating points, and, 2.) Service Fuse Boxes that house the equipment that isolates customer's installations from the network. The enclosures are made from coated steel, concrete, polymer plastics or polycarbonates.

A summary of the enclosure types on our LV system is in the table below.

Table 41 - Summary of LV box types

Enclosure Material	Total
Coated Steel	1,796
Polymer	648
Polycarbonate	59
Unrecorded	222

Distribution cabinets allow the system to be reconfigured if each radial feeder is capable of supplying or is able to be supplied from the feeder next to it. There are two material types used for this sort of enclosure - steel and polycarbonate.

Service fuse boxes are generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service, with most having a steel cover on a steel base frame. Modern types are entirely made from an insulated polymeric material that has additives that reduce the effect of UV degradation.

Coated Steel enclosures were the default type of enclosure on the network until 2008. They are structurally strong but are vulnerable to corrosion due to ground water acidity/alkalinity and can be conductive if a fault occurs with the equipment inside them.

Polymer enclosures are the most used modern type of Service Fuse Box. They are not as structurally strong steel but are not vulnerable to corrosion from ground water acidity/alkalinity. They made of an insulated material which cannot conduct electricity if a fault occurs, but as they are less heat resistant than steel they can be damaged from the heating effect of an internal equipment fault.

Polycarbonate enclosures are the most used modern type of Distribution Cabinet. They are not as structurally strong as steel but are stronger than Polymer enclosures though more vulnerable to impact. They are not vulnerable to corrosion due to ground water acidity/alkalinity like polymers and are made of an insulated material which can't conduct electricity if a fault occurs. They are less heat resistant than steel but better than polymer enclosures.

About 10% of the assets do not have an identified material type. This data issue will be resolved as our new inspection programme captures this and other information.

5.8.8.1 Age profiles and population data

The average life expectancy we apply to enclosures is 45 years. The age and health profiles of the assets is shown below.

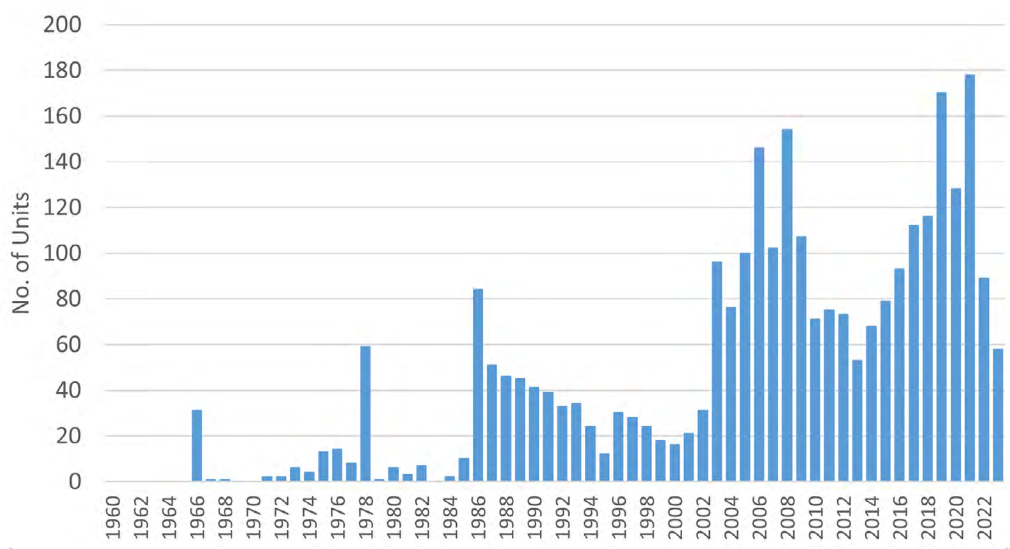


Figure 58 - Age profile of enclosures

5.8.8.2 Asset risks

Major risks to the cable enclosures include

- vehicle impact – many enclosures are built adjacent to public roads and private accessways
- erosion of land around foundations
- material degradation of the asset such as corrosion or UV damage
- overheating of joints and terminations

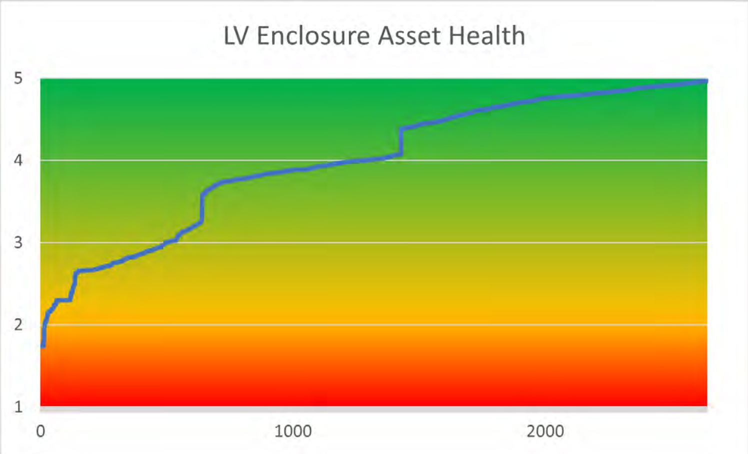


Figure 59 - Health profile of LV enclosures

5.8.8.3 Inspection and maintenance practices

Table 42 - Distribution cable enclosures inspection and maintenance programme

Activity	Summary	Frequency
Condition and security checks	Visual inspection of enclosures to identify any public safety risks	5 yearly
Partial Discharge Testing	Cable terminations as part of visual inspection	5 yearly

5.8.8.4 Renewal and refurbishment programme

Our policy is to replace enclosures when they cannot remain in service until the next scheduled inspection. We believe that this is the correct approach for managing the end of life of enclosures, as it reduces risk by not leaving them in service if they are in a marginal condition.

5.8.9 Distribution switchgear

We use 11 kV reclosers and sectionalisers extensively in rural areas to automatically clear transient faults, and to minimise the areas affected by fault outages. Most of these devices are linked to the SCADA system and can be remotely monitored and operated.

11 kV oil filled ground mount switchgear (individual fused switches and ring main units) have been commonly installed since 1990, as part of the major urban undergrounding programmes that began then, and the more recent network reinforcement programmes.

Distribution spur lines and individual 11 kV service lines to customer premises are often connected to the main feeder via drop out type fuses, or manually operated air break switches. These provide a control point for disconnecting the spur during a fault or planned outage, and the fuses provide a level of discrimination for faults on the fringes of our network, minimising the effect of faults on remote parts of the network. Other such switches are used as manual sectionalising points during fault response or to minimise outages during planned work.

LV switchgear is classified into two groups:

- *Enclosed* switchgear includes vertical, fully shrouded switchgear, such as the Weber Verti-group unit. These have been installed from the early 1990s until now. There are 160 of these on the network.
- *J-Type* switchgear has a variety of types. These were installed on our network between 1964 and 1997. There are 100 of these units on the network.

5.8.9.1 Age and health profiles

Life expectancy for these assets is 35 years for High Voltage overhead equipment, 40 years for High Voltage ground sited equipment and 45 years for LV switchgear. Age profiles for the various sub-types are below.

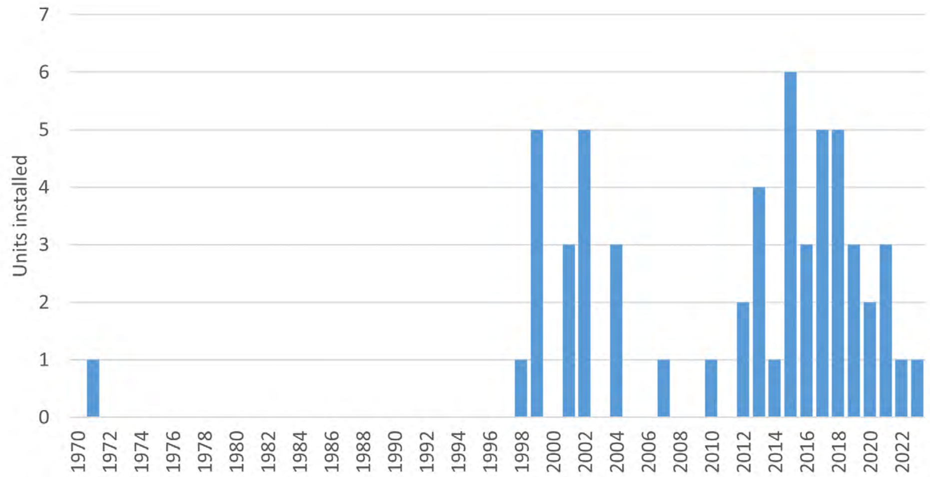


Figure 60 - Age profile of distribution reclosers and sectionalisers

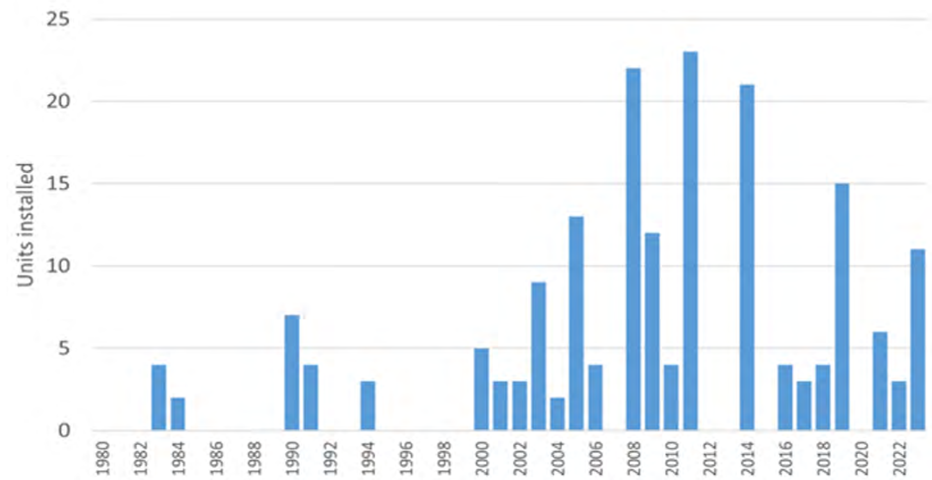


Figure 61 - Age profile of ground sited switchgear (including RMUs)

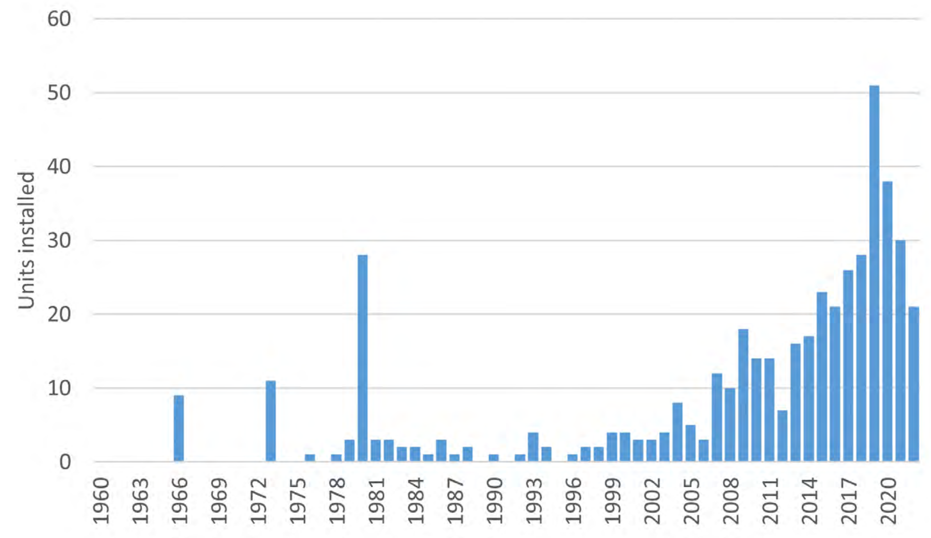


Figure 62 - Age profile of Air Break Switches

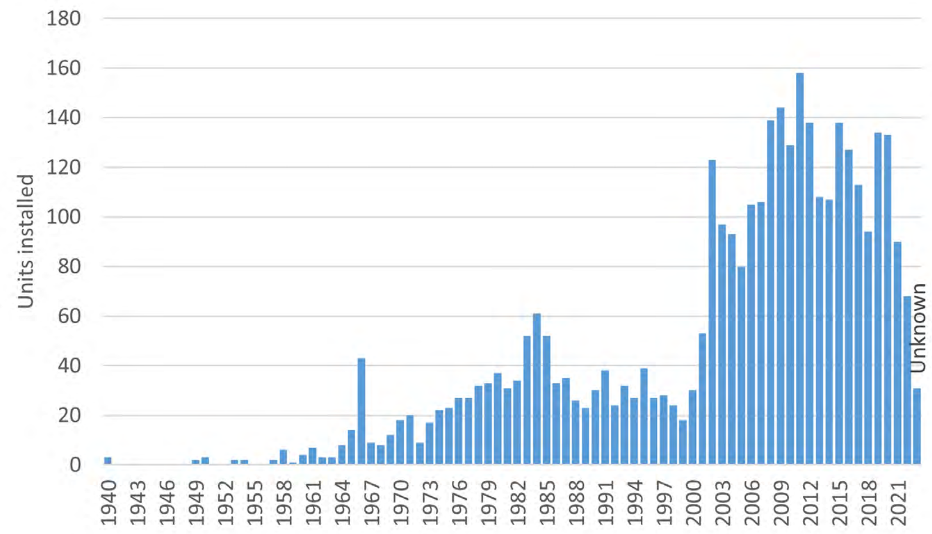


Figure 63 - Age profile of HV fuses

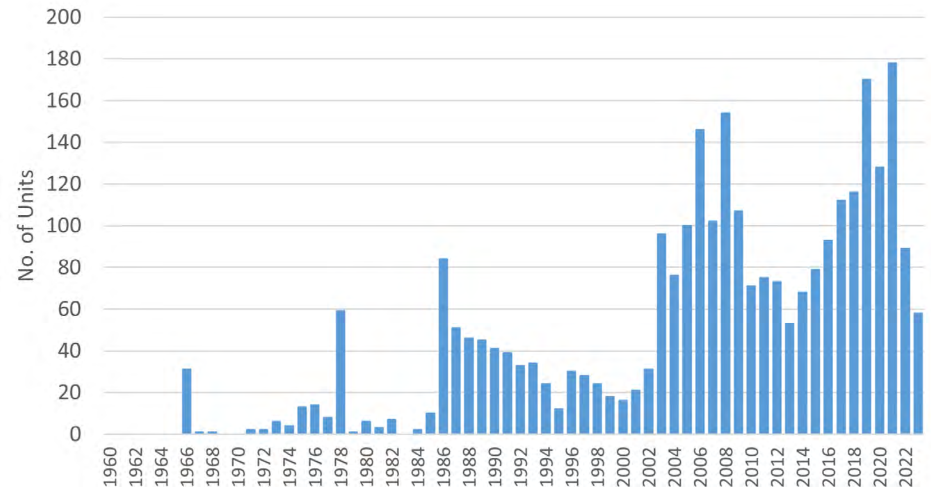


Figure 64 - Age profile of low voltage switch gear

We will often manage distribution switchgear based on the design or age of the equipment, as common failure points become obvious in a particular design. The health profiles of 11 kV distribution switchgear are shown in the following figures:

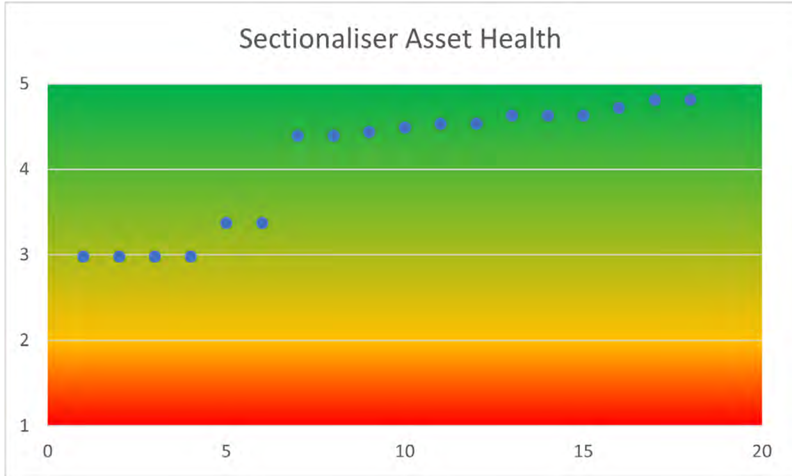


Figure 65 - Health profile of distribution sectionalisers

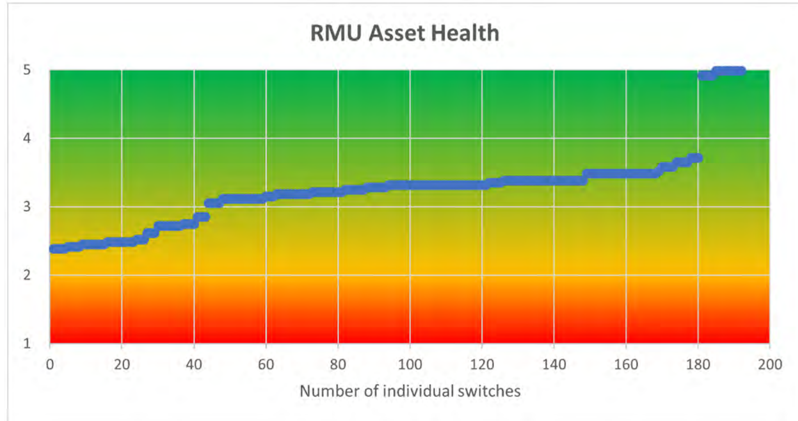


Figure 66 - Health profile of ground mounted distribution switchgear

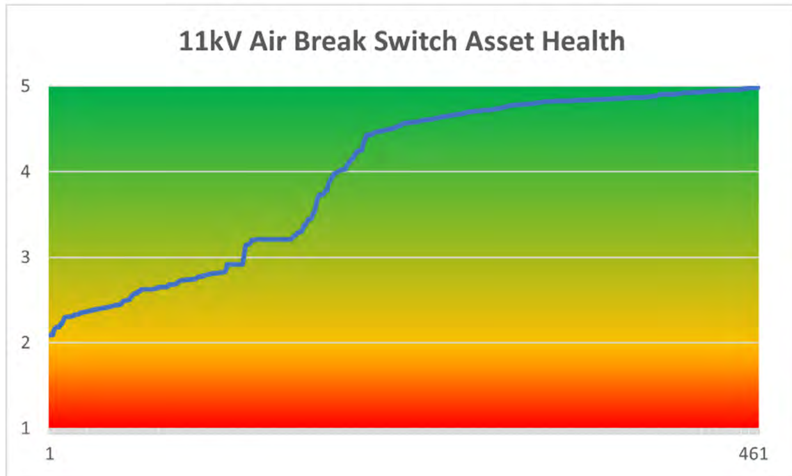


Figure 67 - Health profile of pole mounted air break switches

5.8.9.2 Asset risks

Major risks for the asset class include:

Pole mounted ABSs, reclosers, sectionalisers, pole mounted fuses:

- Lightning – although surge arresters are widely used, a direct strike may be destructive
- Animal contacts, such as possums and birds
- Cracking of porcelain insulators during operation
- Overheating and failure of older fuse gear during service

Ground mounted switchgear:

- Cabinets and casings degrading or becoming unsecure
- Vehicle incidents, as many are located in the road reserve
- Failure due to dirty insulating oil
- Failure of cable terminations on the unit
- Failure of mechanism during switching

The operational risk associated with the failure of distribution switchgear depends on the location and use. In service failure of a sectionaliser or recloser on a major feeder could either lead to the loss of more customers than necessary during a fault (because upstream protection must clear the fault) or prevent a planned alternate feed being used to restore lost load during an outage. By comparison with this, an ABS or fuse on a spur line or a low voltage fuse supplying one house has lower overall operational risk.

Safety related risks are generally lower for pole mounted equipment but can be more important for ground mounted equipment, where operators are standing in close proximity during switching.

Recent operational experience in New Zealand and overseas has shown that older oil filled switchgear can fail during operation in a way that is dangerous to the operator. Following this, we have stopped manual operation of these units and instead use a remote actuator. In practice, these operational restrictions are increasing switching complexity and outage times on the network. We have reviewed and changed our maintenance practices to reduce this risk.

The majority of the oil filled ring main units in service on our network are Andelect/ABB SD types. These units are no longer manufactured and in some cases are not supported by the manufacturer. We are replacing these units at a rate of around three per year with modern vacuum switch ring main units, often with remote SCADA operation. These will be installed in locations selected to enhance our resilience to faults. This will support future "smart grid" features, such as ring feeders with automatic fault isolation and detection. Removal of the oil filled switchgear will provide an ongoing stock of spares for the remaining units in service.

5.8.9.3 Inspection and maintenance practices

Table 43 - Distribution switchgear inspection and maintenance programme

Activity	Summary	Frequency
Line patrol	Visual and thermal inspection of high voltage and low voltage switchgear and terminations, ground mount and pole mount	5 yearly
Condition and security checks	Visual inspection of ground mounted high voltage equipment in high traffic urban areas to identify any public safety risks	Annual
Partial Discharge Testing	11kV Distribution switchgear discharge testing	5 yearly
RMU Maintenance	Cleaning, oil testing, operational testing	5 yearly
Air break switch maintenance	Lubrication, checking operation	5 yearly
Recloser and sectionaliser operational checks	Operational tests and checks. Replace batteries	5 yearly
Insulator checks	Special visual inspection for 11 kV air break switches prone to porcelain insulator failure	6 monthly

5.8.9.4 Renewal and refurbishment programme

The renewal and refurbishment programme for the planning period includes:

- Replace some air break switches with sectionalisers in rural feeders to minimise outage areas during faults.
- Replacement of all 11 kV ABSs of the type prone to insulator failures in the early years of the planning period.
- Replace other switchgear based on condition assessment from scheduled inspections.
- Replace three oil filled ring main units per year with SCADA operable RMUs of the vacuum circuit breaker type to improve operational performance of the network.
- Continuing to replace older J-type low voltage switchgear with more modern enclosed switchgear that is safer to operate.
- Replacing a recently installed ring main unit following discovery of a fault within the production batch.

5.8.10 Distribution transformers

The 11 kV distribution network supplies 2,918 distribution transformers, of which about 400 have a capacity in excess of 100 kVA. All new transformers, 200 kVA or over, are ground mount "mini-sub" configured, irrespective of whether they are installed in an underground or overhead reticulated area. LV reticulation in urban areas is typically supplied by 200-500 kVA distribution substations that are located to accommodate three to four LV feeders. Transformer capacity is normally based on an average After Diversity Maximum Demand (ADMD) of about 5.6 kW for a domestic customer.

An LV distribution switchboard is normally housed in or near the transformer cabinet, with each feeder being independently fused. The LV switchboard is mounted independently of the transformer cabinet and is fitted with an incomer switch to facilitate the isolation and removal of the transformer independent of the LV board. In overhead reticulated areas, transformers are protected by pole mounted expulsion fuses and, in underground reticulated areas, with ground mounted fused oil or vacuum switches. In urban areas, the LV system is run in open rings with tie points brought into ground-mounted distribution boxes or jumper cuts in the overhead reticulated system. Earths for ground-mounted transformers in urban areas incorporate an equipotential earth loop to control step and touch voltages.

Transformers are arranged in a mesh layout such that neighbouring units can support an outage via LV interconnection. Transformers and cables are designed with sufficient spare capacity for this purpose. Maximum Demand Indicators (MDIs) are fitted to determine the need for capacity upgrade and phase balancing. Larger customer supplies may have dedicated LV cables back to the LV distribution frame and/or a dedicated transformer on their own site. Rural supplies tend to have smaller dedicated pole mounted transformers.

Voltage regulators are a special type of transformer installed on the 11 kV distribution network to improve voltage regulation of feeders, especially where there is demand growth due to dairy conversions and irrigation. They are often used as an interim measure until the demand growth warrants reinforcement of the supply. We have 14 installations of voltage regulators in service.

5.8.10.1 Age profiles and population data

The average life expectancy that we apply is 45 years for distribution transformers and 25 years for Voltage regulators. The age profile of our ground and pole mounted transformers is shown below.

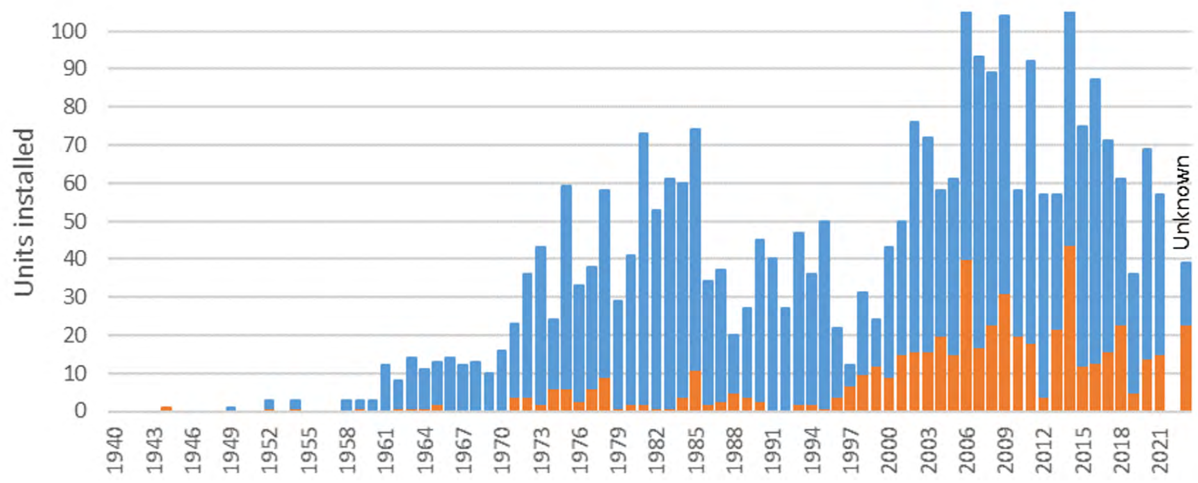
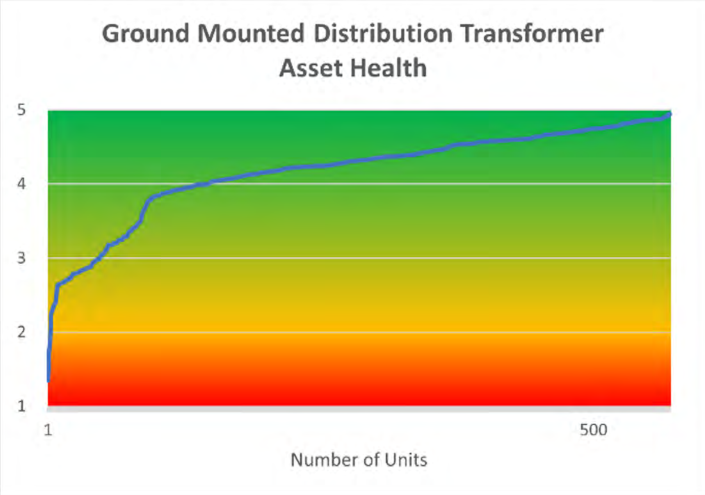
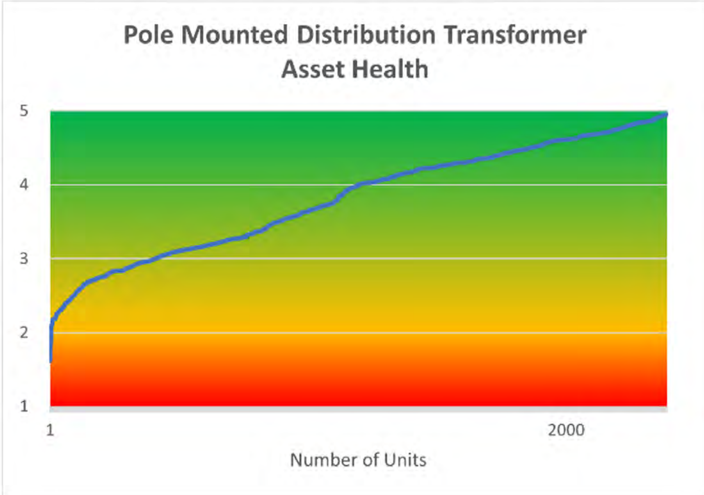


Figure 68 - Age profile of distribution transformers





Figures 69 – Health profiles of distribution transformers

5.8.10.2 Asset risks

The main risks to this equipment class include:

- Oil leaks into the environment
- For pole mount transformers – animal contacts, such as possums and rats
- For ground mount transformers – vehicle incidents, as many are located in the road reserve
- Overloading of CBD transformers due to offloading of adjacent transformers during faults or planned outages
- Corrosion that may cause issues with security of cabinets and doors.

5.8.10.3 Inspection and maintenance practices

Table 44 - Distribution transformers inspection and maintenance programme

Activity	Summary	Frequency
Line patrol	Visual and thermal inspection of transformers	5 yearly
Condition and security checks	Visual inspection of transformers in high traffic urban areas to identify any public safety risks	Annual
MDI reading	Check and record loadings on larger transformers	Annual
Earth testing	Test earth continuity and values	5 yearly

5.8.10.4 Renewal and refurbishment programme

The renewal and refurbishment programme for the planning period includes:

- General condition-based refurbishment work such as painting cabinets, fixing doors, or any safety-related issues.
- Condition based replacements, based on overall condition, or where a transformer is particularly old and is showing signs of end-of-life conditions.
- Overhaul regulator transformers based on manufacturer's recommendations.

Our distribution transformer fleet is generally reliable and robust. We aim to maximise the utilisation of our transformers without overloading them during normal operation, although we will apply a managed approach to short term overloading in the event of a fault.

MDI readings are used to monitor the loading on large transformers. We have completed a small trial of distribution transformer monitoring (DTM) units in some of our larger urban transformers and have seen benefits for our asset management processes compared with the traditional maximum demand indicators, which are manually recorded at longer intervals. A DTM system provides remote monitoring of transformer loading and voltages (actual and historical), allowing much greater information on how our assets are being used, and gives visibility of any overloaded transformers, so we can reduce loading before the transformer life is compromised.

The value of being able to remotely check loading on a distribution transformer has been shown when planning the reconfiguration of open points to ensure that customer load can be met. Rather than a simple maximum, transformer loadings can be understood in the context of the duration of the overload, and the cool down time that follows. These lessons are being factored into the ongoing work to develop a low voltage monitoring system, mentioned in **section 6.2.3**. In addition to the ongoing rollout of the low voltage monitoring system, when a distribution transformer is being replaced, we will take the opportunity to include monitoring equipment where it suits the operational needs of the network.

Both pole and ground mount transformers have proven to be reliable and robust in service, with few equipment failures in general. We are planning to complete a steady number of transformer replacements throughout the planning period, to maintain the average age of the fleet to a reasonable figure. Replacements will often naturally coordinate with other works such as capacity or configuration upgrades.

5.8.11 Total distribution network expenditure forecast

Table 45 - Total distribution network expenditure forecast

Distribution ($000)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Service Interruptions & Emergencies	457	442	425	425	425	425	425	425	425	425
Routine & Corrective Maintenance and Inspections	752	537	664	724	724	724	724	724	724	724
Asset Replacement & Renewal (Pukeuri Alliance cable)	292									
Asset Replacement & Renewal (Single Wire Steel Conductors)	752	280	42	32						
Asset Replacement & Renewal (Other Steel Conductors)	264	44	1,152	702	381	648	733	1,069		
Asset Replacement & Renewal (7/.064 Copper Conductors)		996	139	478	44	510	320	652	1,408	573
Asset Replacement & Renewal (Poles)	1,420	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422
Asset Replacement & Renewal (Other Assets)	1,834	1,715	2,097	2,334	3,165	2,314	2,397	1,747	2,118	3,006
Asset Relocations	185									
Vegetation Management	712	712	712	712	712	712	712	712	712	712
Total	6,668	6,148	6,653	6,829	6,873	6,755	6,733	6,751	6,809	6,862

5.9 Secondary and Support Systems

5.9.1 Overview of secondary and support systems

We use various technologies to enhance the safety and efficient use of the primary Network assets. The associated hardware for these systems is generally co-sited with the assets themselves, but the core elements are centrally located.

5.9.2 Management approach

These systems are managed with the active assistance of manufacturers and suppliers, as we do not have the expertise in house to carry out the higher-level maintenance functions for this equipment.

We have undertaken a strategic review of our communications equipment, including SCADA system and radios. This review highlighted that the systems are at limited risk of cyberattack or other failure, and we expect further improvement with major upgrades over the next three years.

5.9.3 SCADA

Our Supervisory Control and Data Acquisition (SCADA) is a digital model of our sub-transmission, zone substation and high voltage distribution network and supports a range of activities related to the operation, planning and configuration of the electricity network. It directly supports key safety and reliability measures by enabling remote control and management of our electricity network from our Operations Centre and Remote Terminal Units (RTUs). These are connected to field devices when we identify telemetry and control benefits with them.

We operate an Abbey Systems Powerlink SCADA system. The SCADA system is connected to all our zone substations via Abbey Systems RTUs and provides remote control, indication, logging, and alarm status information for key operating assets. In addition, most reclosers and sectionalisers are also connected to the SCADA system and can be remotely controlled.

5.9.3.1 Age profiles and population data

Our SCADA system is about 15 years old, which is the typical life expectancy we allow for this asset.

5.9.3.2 Asset risks

Failure of the SCADA would significantly impact the effectiveness of the control room. A less efficient level of network operation could continue in the field using other means of communication, as well as directing operation at substations and field devices.

The major risk to our SCADA system is hardware failure, as the system operates on specialised PCs. This is to some extent mitigated by having a master and a backup computer. In 2020 a complete offsite control room was commissioned to act as an offsite backup for the main control room.

Field RTUs can also fail but, since they are modular and configurable, they can be easily replaced with spare units held by Network Waitaki Ltd.

5.9.3.3 Inspection and maintenance practices

Monitoring, Testing and Maintenance of the SCADA System is part of a support contract with the SCADA system provider.

5.9.3.4 Renewal and refurbishment programme

Our SCADA system is about 15 years old, which is the typical life expectancy we allow for this asset. We will be investigating options (maintain/upgrade/replace) in 2023 including our long-term requirements. A final decision is expected in 2024 with a view to implementing and putting into effect any changes early in 2025.

RTUs are replaced on failure. Network Waitaki carries a quantity of spares based on historical failure rates. At this stage there is no indication of an increasing trend in failure rates.

5.9.4 Communications

Our communication network is made up of three different voice and data systems that provide an essential ancillary service assisting with the operation of our distribution network. These systems provide contact between our Control Room and operating staff and provide remote indication and control of network equipment. Our communication systems enable us to operate our network and deploy our people efficiently, reducing the impact of faults on customers.

VHF analogue radio – installed in vehicles and handheld portable units. These operate via linked VHF hilltop radio repeaters.

UHF radio data communicates information from remote network devices, indicating the state of the network to our Control Centre.

Public cellular networks are used for mobile voice and data communications for non-operational communication and as a backup for the VHF radio system.

Radio repeaters are sited at Cape Wanbrow, Station Peak and Cloud Hill. They are shared between the UHF Data and the VHF radio telephone system.

5.9.4.1 Age profiles and population data

The typical life expectancy we allow for these assets is 15 years.

5.9.4.2 Asset risks

The failure of our primary Communications systems would significantly reduce the effectiveness of the control room. Network operation could continue in the field using the other means of communication we have, along with manual operation at substations and by way of field devices. These alternative communication systems are owned and managed by other providers.

The major risks to the radio network are:

- Extreme weather events - the remote locations of our repeater sites can make them difficult to access and repair during snow and other major weather events.

5.9.4.3 Inspection and maintenance programme

Maintenance of the Communication Systems involves an annual radio equipment site check.

5.9.4.4 Renewal and refurbishment programme

We are reviewing our overall communications networks and our future needs over the next 12 months. With the development of future network needs, we know that data requirements will require us to invest in our communications systems, therefore a co-ordinated renewal/refurbishment and development plans are essential. We expect to detail our communications plans in our next AMP.

5.9.5 Power quality monitoring

We have recently installed 400V monitoring equipment on selected distribution transformers to aid our understanding of customer behaviours and network responsiveness. We have 44 units installed monitoring 123 low voltage feeders with a target of 100 units to be installed by the end of FY23, a further 100 units to be installed in FY24 and 100 units installed in FY25. The units are installed at ground mount locations in LV distribution switchboards inside transformer cabinets or inside distribution box cabinets, or to pole mount locations. The units measure voltage and current over three phases and up to six LV feeders per unit. The measured data is sent via mobile network to an online hosting service, and is then used to calculate current imbalance, neutral current, congestion, total harmonic distortion, and PV injection.

The ground mount unit housing is made from polycarbonate, and the pole mount unit housing is made of a UV stable polycarbonate for use in outdoor environments. The units are IP 65 rated, and are compact enough to fit into smaller DB cabinets.

A summary of the installation location types on our LV system is in the table below.

Table 46 – Installation types of LV monitors

Installation Location	Total
Ground Mount – Transformer cabinet	22
Ground Mount – DB cabinet	21
Pole Mount	1

5.9.5.1 Age profiles and population data

The typical life expectancy of this equipment is 15 years.

All units were installed in 2023.

5.9.5.2 Asset risks

- Vehicle impact – most units will be located in/on assets adjacent to public roads
- Overheating or failure of electrical components and communication components

- Water/weather ingress in transformer or DB cabinet
- Corrosion on fuse terminals
- Failure of power leads, Rogowski coils and other secondary equipment.

5.9.5.3 Inspection and maintenance practices

Continuous monitoring of the LV monitoring units is undertaken by the vendor under a support agreement. Any abnormalities automatically trigger an alarm and are reported back to Network Waitaki.

LV monitors and secondary equipment are to be replaced upon failure and are to be tested in house before being returned to the vendor.

The LV monitor can be visually assessed for physical condition during distribution transformer inspections.

5.9.5.4 Renewal and refurbishment programme

Given the asset type, age and condition there are no renewal or refurbishment plans for Network Waitaki's LV monitoring units within the planning period.

5.9.6 Load management system relays

Our Load Management (Ripple) System controls electrical loads predominantly by injecting frequency signals over the electricity network. The primary purpose is to defer energy consumption and minimise peak load. This is achieved in two ways: 1.) Customer demand management load reduction and/or generation and, 2.) by distributor-controlled load management through hot-water cylinders and other interruptible loads. A secondary purpose of the system is to allow coordinated management of common load types such as streetlighting.

The system is made up of various electrical plant and hardware/software platforms supplied by Landis & Gyr. A centralised plant injects a carrier frequency (283Hz) with a digital signal into the power network. That signal is acted upon by relays installed at the customer's connection point. Further information on the central plant can be found in section 5.6.8.

We use Decabit ripple control relays at customer premises to control demand to minimise line charge costs and to control network demand below certain constraints. The ripple relays are typically owned by Network Waitaki Ltd, apart from about 200 owned by Waitaki District Council and used for controlling streetlights. Alternative signal means are also used to prepare and initiate some major customer load management methods.

5.9.6.1 Age profiles and population data

The typical life expectancy of this equipment is shown in the table below.

Table 47 - Life expectancy of other fixed network assets

Asset Description	Standard life expectancy (years)
SCADA System	15
Radios	15

5.9.6.2 Asset risks

Failure of the relays would significantly impact customers in the following ways:

- Hot water systems failing to be energised
- Streetlight remaining on or off
- Other customer-controlled equipment failing to be energised

Relays are modular and configurable so can easily be replaced with spare units held by Network Waitaki Ltd.

5.9.6.3 Inspection and maintenance practices

Relays and receivers are replaced on failure. There is no active inspection or maintenance regime.

5.9.6.4 Renewal and refurbishment programme

Relays and receivers are replaced on failure. Network Waitaki carries a quantity of spares based on historical failure rates. At this stage there is no indication of an increasing trend in failure rates.

5.9.7 Total secondary and support system asset expenditure forecast

Table 48 - Total secondary and support system asset expenditure forecast

Distribution ($000)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Service Interruptions & Emergencies	82	82	86	86	86	86	86	86	86	86
Routine & Corrective Maintenance and Inspections	87	93	99	99	99	99	99	99	99	99
Asset Replacement & Renewal	331	1,155								
Total	500	1,330	185	185	185	185	185	185	185	185

5.10 Maintenance and Renewal Expenditure Summary

Forecast expenditure for renewals and maintenance are summarised by asset category in the table below.

Table 49 – Maintenance and renewal expenditure forecast by category and asset type

$000s	Asset Class	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Asset Relocations	Zone Substations	0	0	0	0	0	0	0	0	0	0
	Sub-transmission	36	0	0	0	0	0	0	0	0	0
	Distribution	185	0	0	0	0	0	0	0	0	0
	Secondary & Support	0	0	0	0	0	0	0	0	0	0
Replacement & Renewal	Zone Substations	813	2014	1239	974	820	882	647	928	647	882
	Sub-transmission	299	1132	588	588	610	554	554	314	314	314
	Distribution	4,562	4,457	4,852	4,968	5,012	4,894	4,872	4,890	4,948	5,001
	Secondary & Support	331	1155								
Total	Capex	6,226	8,758	6,679	6,530	6,442	6,330	6,073	6,132	5,909	6,197
Service Interruptions & Emergencies	Zone Substations										
	Sub-transmission	11	12	15	15	15	15	15	15	15	15
	Distribution	457	442	425	425	425	425	425	425	425	425
	Secondary & Support	82	82	86	86	86	86	86	86	86	86
	Vegetation	50	50	50	50	50	50	50	50	50	50
Routine & Corrective Maintenance	Zone Substations	339	325	310	310	310	310	310	310	310	310
	Sub-transmission	193	287	249	192	192	192	192	192	192	192
	Distribution	752	537	664	724	724	724	724	724	724	724
	Secondary & Support	87	93	99	99	99	99	99	99	99	99
	Vegetation	712	712	712	712	712	712	712	712	712	712
Total	Opex	2,683	2,540	2,610	2,613	2,613	2,613	2,613	2,613	2,613	2,613
Grand Total		8,909	1,1298	9,289	9,143	9,055	8,943	8,686	8,745	8,522	8,810

Network Development Plan

06

Network Development Plan

This chapter sets out our Network Development Plan and covers:

- **Planning approach:** Explains our focus, development drivers, planning criteria, and demand forecasting methodology.
- **Network Evolution Roadmap:** Our plan to transform our network to achieve the goals of the ENA Network Transformation Roadmap.
- **Development programs:** We have analysed capacity and security levels for our network over the planning period and presented options to alleviate capacity or security shortfalls.

6.1 Introduction

This plan describes how we will prepare our network to provide for our customers' future energy needs. We discuss how we will enable process heat decarbonisation in our area and how we will ensure our network is ready when our customers decide to take up new technologies such as electric vehicles (EVs) and distributed generation.

Our network does not currently face challenges hosting these new technologies, but we are acting early to better understand our low voltage networks so we can benchmark our performance and monitor growth over time. We discuss our plans in Section 6.2 - Our network evolution roadmap.

Sections 6.3 to 6.7 lay out the assumptions behind our growth forecasts and examine the effects of growth for different scenarios at Grid Exit Point, sub-transmission and zone substation level. We also examine security of supply to customers at distribution feeder level. We expect significant process heat decarbonisation demand before 2027 followed by transport decarbonisation demand becoming significant in the 2030s.

To meet decarbonisation demand, we plan to build a new Grid Exit Point (North Otago GXP) into the Waitaki and Lower South Canterbury regions. Our Board has approved the plan in principle following an independent external review and we are now working with Transpower to refine design and costs so we can produce a final business case for Board approval.

We conclude by discussing network development projects planned over the next 10 years to deliver the safety, reliability, capacity, security, and sustainability service levels that our customers require.

As we develop business cases for these projects, we evaluate non-network options (e.g. solar, batteries, procurement of non-network services from others) and, if these are economically feasible and practical, we will recommend taking them up. For example, in collaboration with Transpower we recently implemented a variable line rating scheme, and are currently designing a Special Protection Scheme on the transmission circuits supplying Oamaru GXP. These non-network projects have provided increased capacity at low cost by extending the capacity of existing assets.

We value our relationships with other Electricity Distribution Businesses and are active members of the following industry groups:

- South Island Distribution Group – Distribution System Operator roadmap/collaboration on trials
- South Island Chief Executives – Direction setting to enable collaboration between EDBs
- EEA Emerging Technology Group – Developing technical guidance for DERs
- ENA Smart Technology Working Group – Developing and enabling Network Transformation Roadmap
- ENA Regulatory Working Group – Working with regulators to develop sound legislation and fair rules
- ENA Consumer Engagement Working Group – Providing strategic direction and collaboration opportunities.

6.2 Our Network Evolution Roadmap

New Zealand must transition away from carbon-based fuels if we are to meet our climate change objectives.

Our country has committed to reducing net emissions of all greenhouse gases (except biogenic methane) to zero by 2050. To achieve this, we will need to move away from coal, petroleum, and other Carbon-based fuels for our process heat and transport needs. It is now clear that electricity will supply a substantial proportion of this energy demand in our region.

We forecast a significant growth in electricity demand this decade as customers who currently use coal for process heat convert to electricity. From 2030, we expect that EV demand will increase significantly, but acknowledge a high level of uncertainty around our growth rate and around charging behaviour assumptions.

Our customers may choose to increase their uptake of Distributed Energy Resources (DER)[6] and new trading arrangements as they become available[7] and their service level expectations may increase as they rely more on electricity. We are currently developing a customer-centric Service Level Standard to replace our traditional Security of Supply Standard. As we develop this, we will consult our customers so we can better understand their current and future expectations.

To enable the transition to electricity, we must work together as a sector. We value our relationships with other Electricity Distribution Businesses and are active members of the following industry groups:

- South Island Distribution Group – Distribution System Operator roadmap/collaboration on trials
- South Island Chief Executives – Direction setting to enable collaboration between EDBs
- EEA Emerging Technology Group – Developing technical guidance for DERs
- ENA Smart Technology Working Group – Developing and enabling Network Transformation Roadmap
- ENA Regulatory Working Group – Working with regulators to develop sound legislation and fair rules
- ENA Consumer Engagement Working Group – Providing strategic direction and collaboration opportunities.

To ensure our network can provide for our customers' future needs, we can no longer treat the future as a projection of the past. This roadmap lays out our plans to meet this challenge and aligns with the ENA Network Transformation Roadmap (NTR), which aims to provide a 'least regrets' pathway to a framework that underpins:

- Sustainable connection of new technology to the distribution network
- Trading of energy and capacity between customers and market participants
- Distributors being well informed on planning, investment, and operational requirements.

We have developed five priority workstreams to enable our goals:

1. Understand our customers
2. Understand our network
3. Improve low voltage visibility
4. Access smart meter data
5. Enable regional growth

Some of these workstreams are interdependent. For example, enabling access to smart meter data allows us to increase our understanding of our customers and network. We present our progress so far and proposed next steps on the following pages.

[6] DER can be defined as a controllable energy resource located in the distribution network and includes Solar photovoltaic systems, EV chargers, battery storage systems, and electric hot water cylinders

[7] For example – Are Ake are currently running a pilot project to investigate multiple trading relationships. Multiple Trading Relationships » Ara Ake

6.2.1 Workstream 1 - Understand our customers

The goals for this workstream are to:

- Increase our understanding of our customers' existing and future energy needs
- Be able to identify Distributed Energy Resource (DER) connections on our network
- Develop a customer-centric service level standard aligned with our customers' needs

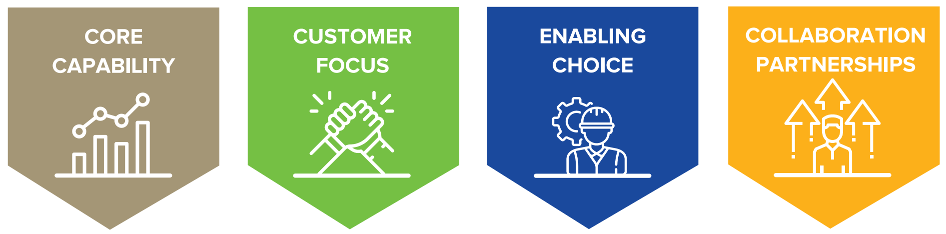
Our progress

- We have completed a study in conjunction with EECA and Transpower to identify and understand process heat conversion opportunities in our area, for coal boilers above 500 kW and for smaller scale boilers at schools. We are working closely with these customers to understand their needs.
- We have analysed smart meter consumption data for 40% of our domestic customers and developed daily locational demand profiles, which we have used as inputs to our demand forecast model.
- We have completed a "proof of value" project with a partner company to extract insights from customer consumption and power quality smart meter data. We were able to present network voltage performance, indicate the low voltage phase each customer was connected to (for customers with power quality data) and present customer demand profiles.
- We have developed customer groups and draft customer service levels.

Actions planned for FY24

- We will refine our EV and distributed generation growth and charging behaviour assumptions in conjunction with the Smart Technology Working Group and will work with others to investigate how we might incentivise EV owners to allow us to optimise their charging behaviour.
- We will continue our research into smaller scale boilers and potential new demand from conversion of domestic gas supplies to electricity from smart meter data in FY24.
- We will quantify customer and network benefits and costs for the smart meter insights project and will develop a business case around smart meter data access.
- We will consult with customer groups to align our draft service levels with their existing and expected future needs and develop our Customer service level standard.

Alignment with our strategic priorities



6.2.2 Workstream 2 - Understand our network

The goals of this workstream are to:

- Understand our network hosting capacity and utilisation, now and in the future.
- Be able to identify and take up opportunities to procure non-network services to manage network congestion.

Our progress

- We have developed a computer model of our network from Grid Exit Point to distribution transformer level and produced forecasts for different scenarios at distribution transformer level.
- We have extended our computer model to customer low voltage level and are currently testing and verifying this model.
- We have completed an EV hosting capacity study with the University of Canterbury for five sample low voltage networks.

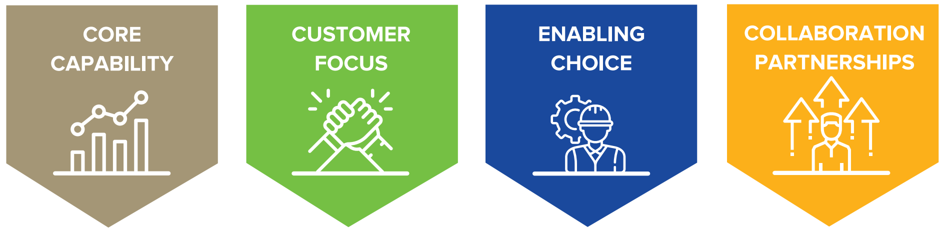
Actions planned for FY24

- We plan to complete our low voltage network model for low voltage planning studies
- We will use load profiles from historical customer smart meter data to build a bottom-up understanding of our existing network maximum demand. This will feed into our Powerfactory and demand forecasting models.
- From the results of our EV hosting study, we will develop investment scenarios for the LV networks studied, to see where we can apply these scenarios across our network. We will then scope and schedule the next phase of the study.

Our plan for 2029

- Our network model will be synchronised with our GIS system to customer level, and we will understand hosting capacity at all network levels.
- We will be able to forecast congestion on our low and medium voltage networks and be able to engage with DER flexibility providers so we can evaluate this as an option for alleviating network constraints.

Alignment with our strategic priorities



6.2.3 Workstream 3 - Improve low voltage visibility

The goal for this workstream is to increase our understanding of our low voltage network by rolling out low voltage feeder monitoring systems.

We traditionally designed our low voltage networks for one way power flows and stable household demand over time. As a result, it was difficult to justify installing smart monitoring systems apart from rudimentary transformer maximum demand indicators to monitor transformer overload. These units do not allow us to understand load duration, power status, power quality, spare capacity, or low voltage feeder demand.

It is important to understand low voltage feeder performance as our customers increase their use of EVs and distributed generation. Feeder cables are not tolerant to overloads and, if damaged, result in high customer impact and are costly to replace.

Fortunately, as the cost of smart devices and network management systems continue to decline, improving low voltage visibility becomes more cost effective. The benefits of this visibility will also increase as customers connect more distributed energy resources (DER) to our network as electrification occurs. It will be particularly important to be able to monitor EV charging patterns at low voltage feeder level to manage the network more effectively.

By understanding existing demand and network performance we will be able to model future demand scenarios and evaluate the best solutions to solve congestion issues ahead of time.

Our progress

We are now monitoring 123 low voltage feeders in real time and are on track to reach our target of 280 low voltage feeders (40% of our customers) by the end of FY23. We are using the monitoring system for network and operational planning and have identified and rebalanced loading on three overloaded low voltage feeders -- which we would not have detected with our legacy transformer maximum demand indicators.

We will install monitoring to an additional 280 urban low voltage feeders to cover 55% of our customers. We will develop our power quality monitoring processes and evaluate how we can integrate real-time information into our control room.

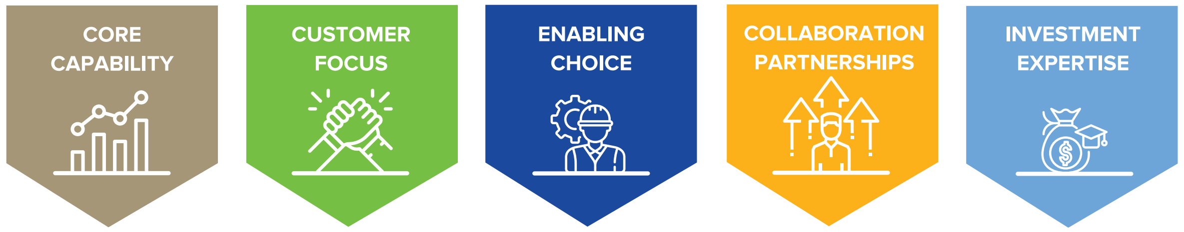
Our plan for 2029

We will be able to monitor a total of 650-700 low voltage feeders by FY28 covering 70% of our connected customers.

We will have benchmarked the performance of our low voltage feeders and have a real-time view of network loading, power quality, outages, congestion, and hosting capacity.

We will be able to augment this information with data from smart meters and other sources to better understand our customers' demand and our network performance.

Alignment with our strategic priorities



6.2.4 Workstream 4 - Smart meter data access

The goal for this workstream is to gain access to smart meter data. Initially, access to historical data will allow us to understand existing customer energy profiles and to model future scenarios and forecast congestion issues. Access to power quality data will allow us to proactively investigate customer power quality issues. We are also investigating whether we can identify customer phase connection and neutral problems from historical data (detailed under Understanding our Customers' workstream).

Ultimately, real-time data will allow us to identify and locate power outages more quickly and improve fault response times. Integrating this with future operational systems may allow us to improve customer service levels by informing them of power outages and restoration times.

Smart meter data will augment the data we receive from our low voltage monitoring system, and this workstream is also an enabler for the Network Understanding workstream.

Our progress

We have received smart meter consumption data from a retailer for 40% of our domestic customers and a sample of irrigation customers.

We have also received a trial dataset of smart meter power quality data for one hundred ICPs from a Metering Equipment Provider. We are running a pilot project to analyse the data and to evaluate customer and network benefits.

We provide details on how we will use these datasets in the Understanding our Customers' workstream.

Actions planned for FY24

If the pilot project is successful, we will produce a business case to evaluate the benefits of receiving a larger dataset. We will continue to support industry efforts to allow cost-effective access to standardised smart meter data though our membership of industry working groups.

We are currently developing a Digital Network Strategy and execution plan which will address how to address data storage, access, and security.

Alignment with our strategic priorities

CORE CAPABILITY

CUSTOMER FOCUS

ENABLING CHOICE

COLLABORATION PARTNERSHIPS

6.2.5 Workstream 5 – Enabling regional growth

The goals for this workstream are to enable decarbonisation in our area and the wider region by ensuring we have enough capacity available in time for our customers to decarbonise their process heat needs in the medium term and transport needs in the medium to long term.

Our forecasts indicate that Oamaru Grid Exit Point will reach capacity in FY24. We plan to install a Special Protection Scheme to allow us to increase capacity at Oamaru GXP, provided we shed load if we have an outage on one of the transmission circuits supplying the GXP. This increased capacity will be exceeded in FY27, when a large user is likely to convert from coal to electricity for their process heat needs.

Our analysis indicates that the best option to enable our customers to decarbonise is to construct a new Grid Exit Point in the Black Point area before FY27. This will allow us to progressively offload our Oamaru GXP as demand increases.

We plan to design the new GXP with options to reconfigure it to resupply Oamaru GXP directly via a 110 kV network. This would free up significant capacity into the South Canterbury region and may allow Transpower to feed into their 110 kV transmission system at this point and avoid planned line and transformer upgrades. There will be additional up front costs to provide these options and we will work with Transpower and Alpine Energy to ensure we make the best choices for New Zealand as we finalise our plans.

We provide further detail on this project in Section 6.5 GXP Capacity and Security and Section 6.8.1 GXP Projects

Our progress

We are on track to have a Special Protection Scheme in place before Spring 2023.

Our Board has approved our preliminary business case to build a new GXP and Transpower has completed the first stage of a Solution Study Report (SSR) to develop a draft GXP layout.

Actions planned for FY24

We will look to secure land for the GXP and engage with key stakeholders. We have engaged Transpower to produce a Solution Study Report (SSR). Once we have the final SSR, we will produce a final business case for approval by our Board. Once approval is granted, we will progress the project with a scheduled completion date in the Spring of 2026.

Alignment with our strategic priorities

CORE CAPABILITY

CUSTOMER FOCUS

ENABLING CHOICE

COLLABORATION PARTNERSHIPS

INVESTMENT EXPERTISE

6.2.6 ENA Network Transformation Roadmap (NTR) alignment

We developed our plan to align with the NTR. We have analysed our progress against the NTR using the five stages approach developed in the 2022 NTR update (Initial, Emergent, Developing, Mature, and Leading).

Foundational actions are the highest priority and support downstream workstreams.

Dependent actions rely on foundational actions being completed first.

Independent actions are stand alone and not dependent on other actions. Many of these will be completed in collaboration with our peers and others via industry working groups.

Table 50 – NTR alignment plan

NTR category	NTR actions	NTR stage	Our comments
Information	Access to smart meter data	Developing	See NWL Workstream 4 – Smart meter data access.
	LV monitoring	Developing	See NWL Workstream 3 – Improve LV visibility.
	Understand DER deployment	Emergent	We currently have low penetrations of DER in our network. We have trialled identification of EVs and DGs from smart meter data.
	Network stability	Emergent	We have a working model of our high voltage network to distribution transformer level and have conducted EV hosting capacity studies on sample LV networks.
	Provision of network information	Emergent	We provide network information in our Asset Management Plan and produce information from our network model on demand for customer and operators.
	Network understanding	Emergent	We are collecting information from our low voltage monitors, have developed a network model to distribution transformer level, and are developing a low voltage network model.
Procurement	Demand response framework	Initial	We will work with our peers via industry working groups to develop a demand response framework and transition plan in FY24.
	Develop contracting for network support	Emergent	We have access to processes and guidance from our peers who have contracted for network support and plan for a trial procurement for network support in the next three years.
	Third party DER/DR for network support	Initial	We will develop our action plan once we have established the foundational actions and as markets develop.
	Enable distribution network trading	Initial	We will develop our action plan once we have established the foundational actions and as markets develop.
	Off-grid power supplies	Emergent	We have access to processes and guidance from our peers who have successfully installed OGPS and have evaluated an OGPS as an option instead of a remote line rebuild. OGPS is an option we consider when we need to build or renew assets in remote areas.
Standardisation	Understand new distributed generation	Developing	We have a good understanding of existing DG and have aligned our standards with Aurora to improve consistency of approaches.
	DER connection codes	Developing	We have aligned our DG connection standard with Aurora's new standard.
	Appliance/DER connection standards	Initial	We will contribute to working groups as appropriate and adopt new standards as they are developed.
	Cybersecurity for DERs	Initial	We will contribute to working groups as appropriate and adopt new standards as they are developed.
Consumer driven	Understand new loads	Developing	See NWL workstream 1 – Understanding our Customers
Asset management	Network engineering	Emergent	We seek to align our standards with our peers where appropriate.
	Asset management practice	Developing	See section 4.6 Asset Management Maturity

6.3 Our Planning Approach

6.3.1 Our planning process

The main drivers for network development projects are:

- Customer demand growth
- Security of supply
- Readiness for the future
- Customer reliability
- Quality of supply

When a driver is identified, we:

- Evaluate and quantify risks and produce a strategic case for change
- Produce a list of network and non-network options (including procurement of solutions from others)
- Analyse the long list of options for technical ability to solve the problem
- Perform economic "whole of life" analysis of short-listed options and evaluate risk improvement for each option
- Develop a business case and recommend a preferred option

Once a business case is approved, we will program the project. Once a project is complete we will review that it delivered the expected benefits.

6.3.2 Our planning criteria

6.3.2.1 Safety criteria

The safety of our people and the public is paramount and non-negotiable at all stages of planning, design, and construction. We hold Safety in Design reviews to ensure new designs (or new standard designs) are appropriately reviewed before we construct them.

6.3.2.2 Energy efficiency criteria

We configure our network to minimise voltage drop and maximise efficiency under normal operating configurations.

We do not directly benefit from reduced losses on our network, as we pass these costs directly to our connected customers. However, in line with our mission and vision, we aim to minimise the total costs of electricity to our customers. For example, in our business cases (where appropriate) we factor in the net present value of energy losses into our cost benefit calculations. This may lead us to select a larger conductor than we initially need to minimise lifecycle energy losses.

6.3.2.3 Quality of supply criteria

The Electricity (Safety) Regulations 2010 require that we maintain the voltage at the customer point of supply at 230 V +/- 6% (except for momentary fluctuations). This influences the design voltage performance for our network which is detailed further in our Network Design Standard NS10/10.

Harmonic voltage limits are specified in our Network Harmonics Standard NS15-05 and NZECP36:1993 New Zealand Electrical Code of Practice for Harmonic Levels.

6.3.2.4 Environmental and sustainability criteria

When we analyse options for a solution, we consider whole-of-life environmental impact and sustainability – two important considerations for us. For example, where possible we choose vacuum-type switchgear instead of Sulphur Hexafluoride (SF6) type, because SF6 is a potent greenhouse gas.

6.3.2.5 Equipment rating and selection criteria

Where available, we take equipment ratings from nameplate data or manufacturers' published data. Where this is unavailable, we will calculate ratings from first principles or estimate these from similar equipment.

We select conductors and switchgear to be able to meet high-growth scenario future demand, provided the incremental cost of upsizing is less than the cost to upgrade the equipment in the future.

Depending on the timeframe and certainty of projected demand, we may size distribution transformers for immediate demand and upgrade them later as demand appears. This minimises network losses and the risk of stranding our assets if the demand does not eventuate.

The first stage in our design process is to check whether we have a standard design or whether we can find one developed by others. We design network assets using standard sizes and models to minimise spares, maximise interchangeability, and reduce stock levels. We specify our standard equipment sizes in our design standards.

We are collaborating with peer South Island EDBs to develop an overhead line design standard and standard pole constructions. We are also members of the Southern Buyers' Group, which aims to standardise equipment and materials between members and to benefit from increased purchasing power.

6.3.2.6 Security of supply and reliability criteria

We are currently developing a Customer Service Level Standard to replace our traditional Security of Supply Standard. As we develop this standard, we will consult with our customers to understand the service levels they need and will adjust our draft customer groups and service levels we have developed. We plan to use this new standard to develop the 2024 Asset Management Plan.

We have used our existing Security of Supply Standard for this (2023) Asset Management Plan.

Security of supply refers to the ability of our network to meet our customers' demand for energy delivery without interruption. We present our deterministic security criteria on the following page.

Where we breach these deterministic criteria, we may conduct probabilistic analysis to determine the likelihood of an outage and to quantify the financial impact and risk.

Where possible, we calculate the probability of failure for a particular class of equipment from our own statistics. Where we have insufficient data, we consult industry guidelines such as the EEA Guide for Security of Supply and IEEE standard 493.

We treat the calculated risk value as a benefit against the cost of potential solutions in our net present value analysis.

Security of Supply notes

- We define repair time as the time taken to repair faulted assets so they can be brought back into service. It includes the time we take to locate and isolate the fault.
- We may negotiate security levels individually with large or non-standard customers.
- The security criteria are based on the ability to interrupt irrigation demand for up to 48 hours per event.

Table 51 - NWL Security of supply standard - deterministic criteria

Class	Description	Demand Size (MVA)	First Outage	Second Outage	Bus Fault or Switchgear Failure
Grid Exit Points (GXPs)					
A1	Urban GXPs	Any	No interruption	Restore 50% in switching time and restore rest in repair time	No interruption for 50% and restore rest in 2 hrs
A2	Rural GXPs	>15	Restore 75% in switching time and restore 90% in 8 hrs	Restore 100% in repair time	Restore 100% in repair time
A3	Rural GXPs	<15	Restore 50% in switching time and restore 90% in 12 hrs	Restore 100% in repair time	Restore 100% in repair time
Zone substations and sub-transmission feeders					
B1	CBD zone substation	Any	No interruption	Restore 100% in repair time	No interruption for 50% and restore rest in 2 hrs
B2	Urban zone substation	Any	No interruption	Restore 100% in repair time	Restore 100% in repair time
B3	Rural zone substation	>12	No interruption for 50% and restore rest in switching time	Restore 100% in repair time	No interruption for 50% and restore rest in switching time
B4	Rural zone substation	2-12	Restore 100% in switching time	Restore 100% in repair time	Restore 100% in repair time
B5	Rural zone substation	<2	Restore 50% in switching time, restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
B6	Sub-transmission feeder	>15	No interruption	Restore 100% in repair time	Restore 100% in repair time
B7	Sub-transmission feeder	<15	Restore 100% in repair time	Restore 100% in repair time	Restore 100% in repair time
Distribution feeders and substations					
C1	Urban 11 kV feeders & CBD LV reticulation	1-4	Restore 100% in switching time	Restore 100% in repair time	Restore 100% in repair time
C2	Urban 11 kV spurs & LV reticulation	<1.5	Restore 50% in switching time and restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
C3	Rural 11 kV feeders	1-4	Restore 50% in switching time and restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
C4	Rural 11 kV spurs & LV reticulation	<1.5	Restore 100% in repair time	Restore 100% in repair time	Restore 100% in repair time

6.4 Our Demand Scenario Assumptions

Our customers' electricity demand has steadily increased at an average of 2% per year over the past two decades. This has largely been driven by irrigation growth and as a result our network peak demand occurs in the irrigation season (normally between October and February).

Over the planning period we expect that irrigation growth will slow and decarbonisation demand (initially process heat conversion followed by transport decarbonisation) will become the dominant drivers of growth.

We use a time-series model to create demand scenarios through to 2050 to account for a full penetration of EVs aligning with New Zealand's carbon-zero goals. For each year we:

- Divide historical maximum demand at each substation into domestic, commercial, and farming categories
- Add likely new demand to each substation under the appropriate category (we include large process heat conversion demand under the Commercial/Industrial category)
- Apply residual growth rates for three scenarios (low, expected, and high growth) to each category (Note: We don't apply these to the new demand component)
- Recombine domestic, commercial, and farming categories to calculate year-end demand.

6.4.1 Domestic demand growth

Our expected domestic demand growth for the next 20 years is shown below for low, expected, and high scenarios. It is based on our growth assumptions for population, EVs and distributed generation which are presented in the following sections.

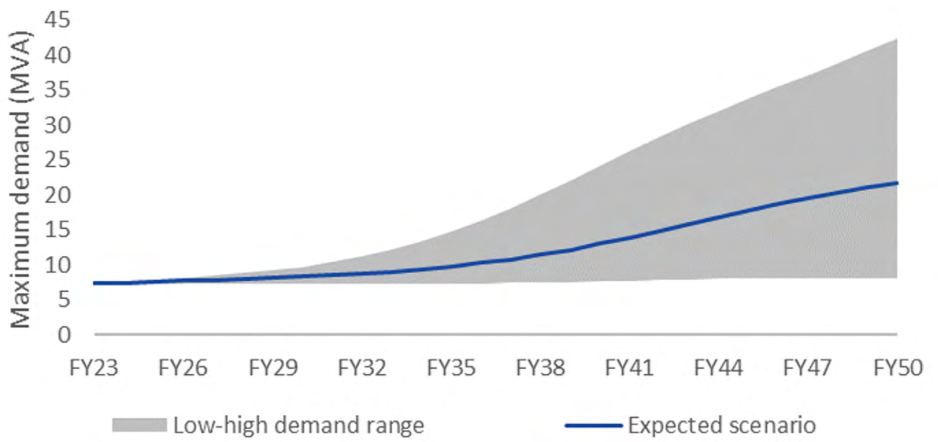


Figure 70 - Domestic demand growth scenarios

The large variation between the low and high scenarios is due to the uncertainty around the impact of EV charging, which is detailed later in this section.

6.4.1.1 Population growth

Over the past five years we have seen domestic customer dwelling connections increase at an average rate of 0.9%. We have aligned our high and low growth scenarios with Waitaki District Council's dwelling growth scenarios, with our expected growth rate continuing at 0.9%.

Table 52 - Domestic growth scenario rates

Growth scenario	Annual growth
Low growth	+ 0.13%
Expected growth	+ 0.90%
High growth	+ 1.59%

6.4.1.2 Electric vehicles (EVs)

We have aligned our EV penetration scenarios with published industry projections as per the graph below.

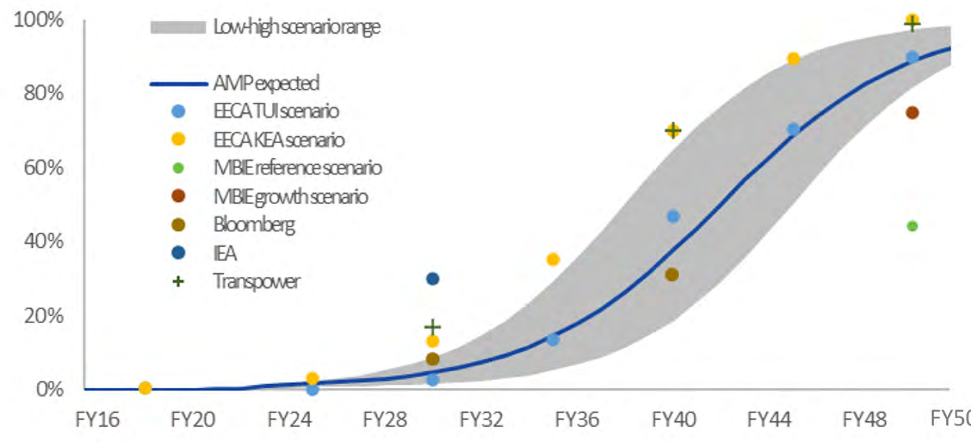


Figure 71 - EV penetration scenarios

We currently have low levels of EVs in our network area (75 battery EV and 37 Petrol Hybrid EV).

EVs currently make up 0.6% of the New Zealand passenger vehicle fleet and 0.4% of the vehicle fleet in our district. The low penetration in our area may be due to our rural workforce favouring traditional utility vehicles, and because EV economics stacks up better in larger urban centres with longer commutes and higher average incomes.

We assume an average of 1.8 EVs per household for 100% penetration and have allowed for charger impacts on our network peak network demand ranging from 0.6 kVA to 1.5 kVA[8]. Our assumptions are summarised below:

Table 53 - EV demand assumptions

Growth scenario	EV charger impact on peak demand	Penetration rate by FY32
Low growth	0.6 kVA	3%
Expected growth	1.0 kVA	9%
High growth	1.5 kVA	19%

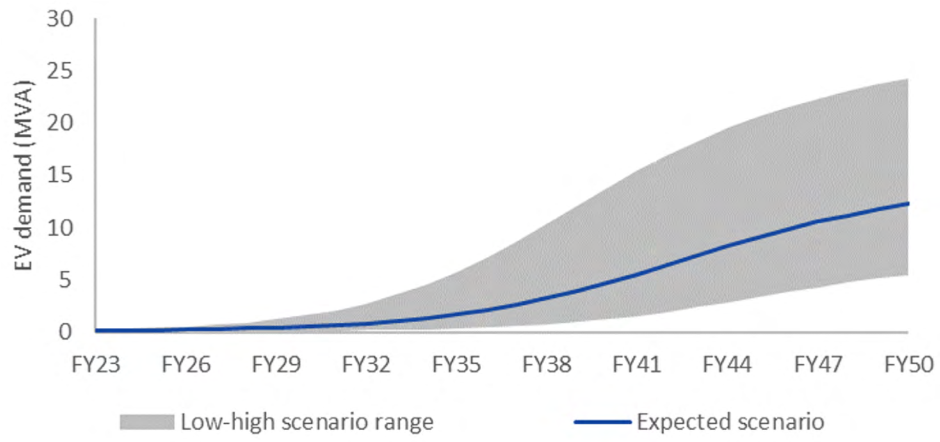


Figure 72 - Total EV load contribution to maximum demand (all GXPs)

[8]For example, the expected EV charger impact on peak demand is calculated as 5 kVA average charger size with 20% of chargers operating during network peaks.

These scenarios indicate minimal impact of EVs over the planning period (0.7-2.2 MVA) but a significant increase in the following 10 years. The FY50 low and high scenario impacts range from 5 to 23 MVA, which is largely due to the uncertainty in our assumptions on charger size and customer behaviour at peak demand times.

We will continue our research in FY24 to refine our assumptions and will use the results from our study with the University of Canterbury to adjust our scenarios (See **section 6.2.1 Understanding our Customers workstream** for more detail on this study).

6.4.1.3 Distributed generation

We welcome distributed generation (DG) on our network. If it is small-scale (less than 5 kW single phase or 10 kW three phase), has an approved inverter with advanced power quality modes, and is in an uncongested area, we will fast-track the connection process.

Areas that are subject to export congestion or that we expect to become congested in the next 12 months are listed on our website www.networkwaitaki.co.nz. We have no areas subject to congestion as of 1 April 2023 and do not expect any to become congested in the following 12 months.

DG in our region is predominantly small-scale photovoltaic panels, and this continues to grow. There are 179 DG connections approved on the network, comprising 1.4% of all connections. The average domestic photovoltaic DG installation size is 5 kW.

We have based our growth scenarios to align with scenarios in the recent Boston Consulting Group decarbonisation roadmap[9]. We estimate the reduction in network demand from solar generation to be 5% of the DG rated power based on statistical analysis of worst-case solar performance under full cloud during peak network demand (which occurs in the morning and evening).

Our main assumptions are summarised in the table below.

Table 54 - Distributed generation growth assumptions

Growth scenario	DG average size	Percentage penetration by FY32
Low growth	5 kW	6%
Expected growth	5 kW	4%
High growth	5 KW	2%

Using the assumptions in the table, we created the following model to represent residential DG growth until 2050.

The uptake of DG may increase as supply costs decrease, electricity costs increase, or due to regulatory changes to. We will continue to refine our models and collaborate with other similar EDBs to share knowledge.

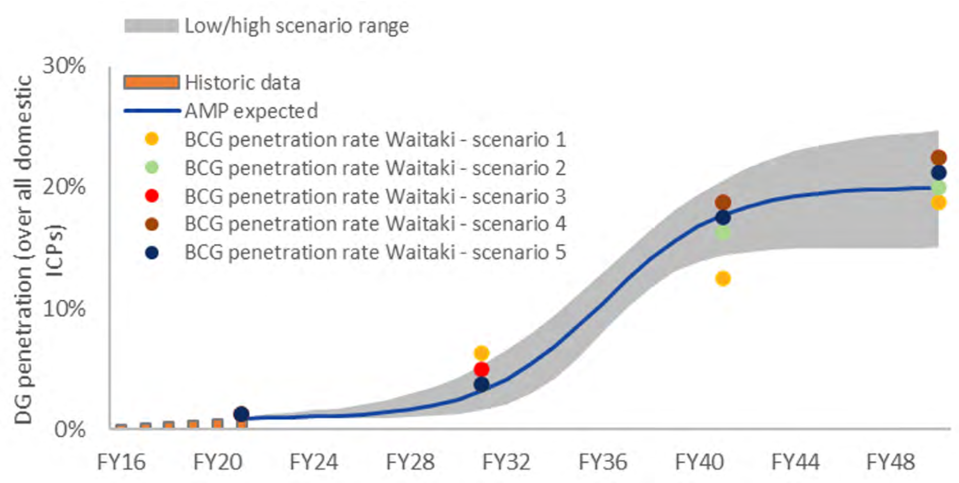


Figure 73 - Distributed generation penetration forecast

[9] BCG scenarios are taken from Boston Consulting Group report – The future is electric the-future-is-electric-full-report-2022.pdf (bcg.com)

We are also aware of a significant number of large-scale photovoltaic projects underway across New Zealand. Large scale schemes will likely connect to our network at high voltage levels and will be examined on a case-by-case basis as applications are received.

The assumption of 5% impact on maximum demand results in a negligible reduction in demand from DG, as shown below. (Note: Expected and low growth scenarios converge in FY50 due to population growth assumptions).

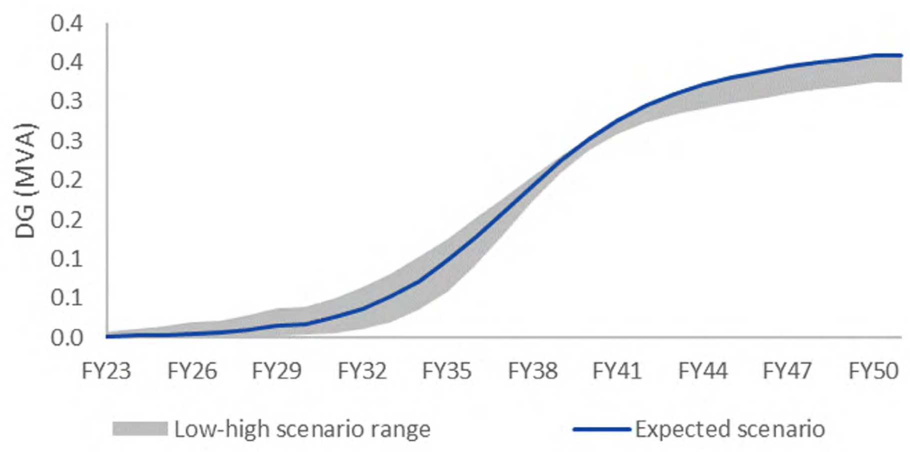


Figure 74 - Distributed generation demand scenarios

6.4.1.4 Battery storage

We currently have 30 customer battery installations connected to our network. All are associated with solar installations with a total installed capacity of 278 kWh. As battery costs fall and value streams emerge for the use of battery flexibility services, we expect to see an increase in distributed battery capacity connected to our network.

Due to the low number of batteries, and uncertainty around how they will impact the network, we have not included effects from batteries in our growth scenarios. The ability to use flexibility services from batteries may be useful to solve network constraints and as flexibility services develop, we will evaluate these in our business cases.

6.4.1.5 Energy efficiency

As customers upgrade to LED lighting, improved building insulation, and more efficient appliances and motors, we expect a decrease in demand from these loads.

We model the reduction in demand from energy efficiency as:

Table 55 – Energy efficiency scenarios

Growth scenario	Annual growth
Low growth	-0.5%
Expected growth	-0.4%
High growth	-0.3%

6.4.1.6 Heat pumps

A significant amount of domestic heating in our supply area is provided by wood burners. The Waitaki area is not subject to clean-air rules beyond the Ministry for the Environment's Authorised Wood Burner List, and we do not expect a large-scale conversion of existing wood burners to heat pumps in the planning period.

Local heat pump installers estimate between 6,000 and 7,000 homes have a single heat pump, and 1,000 have two. We expect that new house builds will include heat pumps and customers will replace older heat pumps with efficient modern inverter units as these reach end of life.

We can't currently quantify the impact of heat pumps on our summer peak demand, but local installers advise that most of their customers don't currently use heat pumps for cooling. There is a risk that customer behaviour may change on very hot days and cause unexpected peak demand. In the short-term we will manage this risk by controlling hot water demand.

In FY24, we will examine the effects of heat pump use in our area through our low voltage feeder monitoring system, and attempt to identify heat pump demand from smart meter data.

Table 56 - Heat pump growth scenarios

Growth scenario	Annual growth
Low growth	-0.1%
Expected growth	0.6%
High growth	0.9%

6.4.1.7 Demand response management

We are using demand response management to move a significant amount of hot water heating demand outside network peaks and into the 11pm to 7am period.

We also have about 1 MVA of hot water heating demand that we can control if required. We do not include this as a demand reduction in our demand growth scenarios, as we reserve this for managing unexpected distribution system peaks and grid emergencies and must use this carefully to avoid large peaks when we restore demand. We expect to continue to rely on our ripple control system for grid and network stability purposes in the short to medium term.

We can also control large irrigation pumps during a distribution or grid emergency via our ripple control system on a per feeder basis. The use of irrigation pump control is limited to distribution or grid emergencies.

We have yet to see the effect of customer-led demand-side flexibility (over and above hot water demand management). As we increase our understanding of our low voltage networks and new flexibility markets emerge, we will be able to evaluate flexibility services as an option to solve network constraints and defer capital investment.

6.4.2 Commercial and industrial demand growth

6.4.2.1 Base demand growth

Over the last 10 years we have seen connected capacity increase at an average annual rate of 0.9%. We expect base growth to continue at this rate and expect to see significant additional growth from process heat decarbonisation.

Table 57 - Commercial demand growth scenarios

Growth Scenario	Annual Growth
Low growth	0.25%
Expected growth	0.9%
High growth	1.2%

6.4.2.2 Process heat decarbonisation

In FY22, we commissioned (along with Transpower and EECA) a detailed study to determine the number of coal boilers greater than 500 kW in our supply area and to understand potential replacement energy sources and conversion timeframes. The study also included schools that are currently using coal for heating. The study found that an additional 10 MW of electricity demand will likely be required by 2030.

We have had commitment from customers for the following projects in FY23, totalling 4.45 MW:

- 0.5 MVA supply for quarry to convert from diesel – completed.
- 0.2 MVA supply for two salmon farms to convert from diesel – completed.
- 3 MVA supply for textiles plant – committed for installation in FY24.
- 0.75 MVA supply for meat processing plant – committed for installation in FY24.

We are working closely with a large customer who may require up to 5.3 MVA of additional supply as early as FY27.

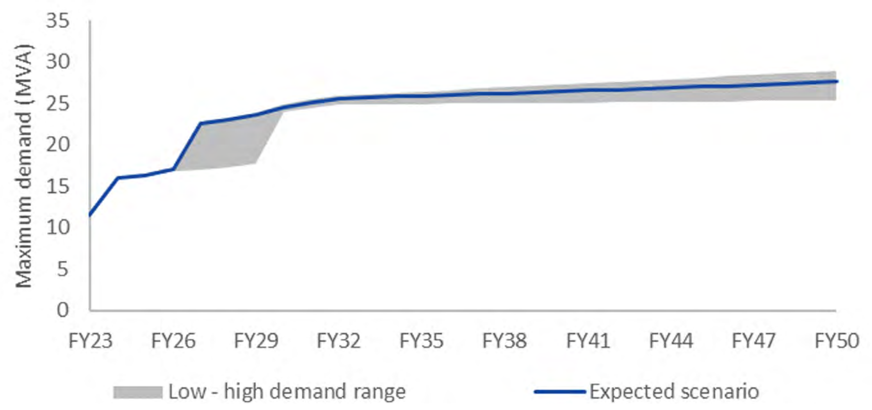


Figure 75 - Future commercial growth scenarios at all GXPs (including decarbonisation load)

6.4.3 Farming demand growth

6.4.3.1 Dairy shed growth

Over the last 10 years we have seen connected capacity increase at an average annual rate of 2.0%, falling to 0.6% over the last five years. We received no new dairy shed connections in FY22.

Conversations with the farming community indicate we are unlikely to see many future dairy shed conversions in the area supplied by Oamaru GXP.

6.4.3.2 Irrigation demand growth

Over the last 10 years we have seen connected capacity increase at an average annual rate of 3.2%, falling to 1.8% over the past three years and 0.5% over the past year, indicating a slowdown in irrigation expansion. We talk regularly with farmers and irrigation companies to understand upcoming projects.

We expect the following irrigation projects to connect to the Oamaru GXP over the next 10 years.

An irrigation company advises that customers in the Lower Waitaki area plan to convert about 4,000 hectares of land from gravity (border dyke) to spray irrigation over the next eight years. We expect this will result in 3.2 MVA of new demand.

An irrigation company advises that customers in the Waiareka Valley Road, Taipo Road, and Dunrobin Road areas may connect an additional 0.4 MVA of irrigation demand.

Once these projects are completed near the end of the decade, we expect irrigation growth in the region will decrease as most viable land is irrigated. For this reason, we have reduced the base growth rate to 0% in FY42. A linear interpolation is then used to calculate growth rates for all years in between.

Table 58 - Farming demand growth scenarios

Growth scenario	Initial annual Growth	Growth rate in FY42
Low growth	0.1%	0%
Expected growth	0.25%	0%
High growth	0.5%	0%

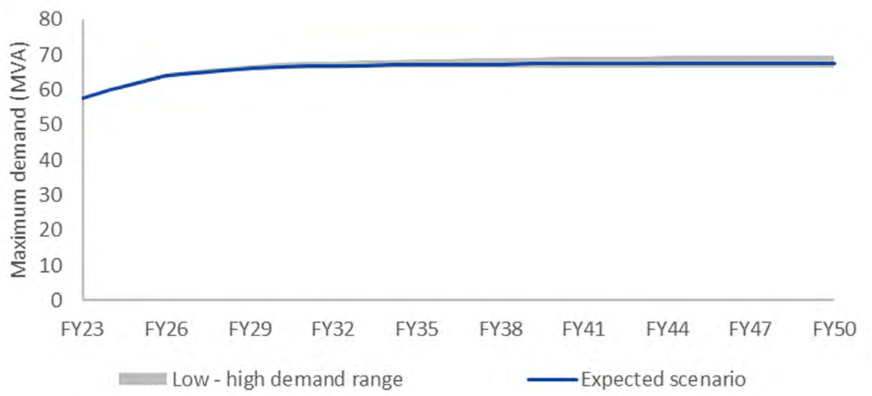
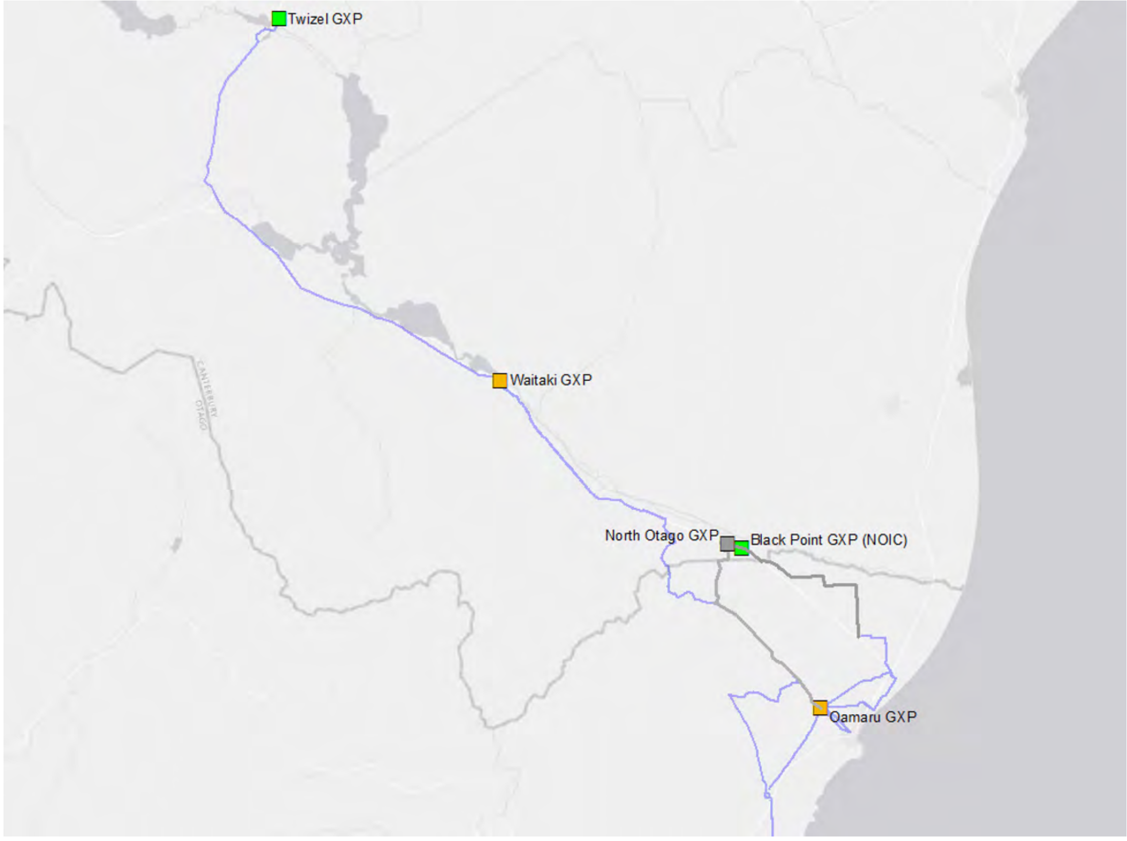


Figure 76 – All GXPs - Farming demand growth scenarios

6.5 GXP Capacity and Security

6.5.1 GXP locations



Key

Key	
Capacity & Security OK	
Security shortfall	
Capacity shortfall	
Not in service yet	

Figure 77 - Network Waitaki GXP locations (capacity and security rated for FY23 period)

Table 59 - GXP details

Grid Exit Point	Voltage	Supply configuration	Capacity	FY23 Max demand (Non-Coincident)	FY23 Zone Substations supplied
Oamaru GXP	33 kV	(n-1) (n) (FY24)	45 MVA 53 MVA	39.4 MVA	10
Twizel GXP	33 kV	(n-1)	27 MVA	3.5 MVA	3
Waitaki GXP	11 kV 33 kV	(n) (n-1) switched	24 MVA 5.5 MVA	11.7 MVA	4
Black Point GXP	110 kV	(n)	25 MVA	14.0 MVA	0
North Otago GXP (proposed)	33 kV (FY27) 110 kV (FY33)	(n-1) (n-1)	23 MVA 120 MVA	-	-

6.5.2 Oamaru GXP

Configuration – Dual 60 MVA power transformers, Dual 45 MVA transmission circuits

GXP security rating – 45 MVA (n-1), 53 MVA (n) – with Special Protection Scheme in service

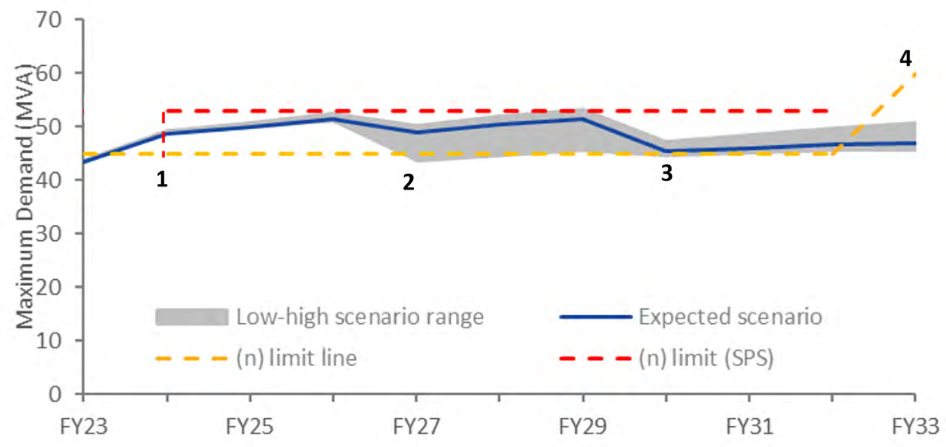


Figure 78 - Oamaru GXP demand growth scenarios

Table 60 - Key events in demand scenarios

Marker	Period	Description
1	FY24	• Special Protection Scheme in service - capacity increased to 53 MVA with up to 8 MVA at (n) security • 3 MVA process heat decarbonisation project connected (confirmed)
2	FY27	• North Otago GXP in service at 33 kV • Awamoko Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP • Papakaio Sub (5.3 MVA) transferred from Oamaru GXP to North Otago GXP • Expected and High scenarios - 5.3 MVA decarbonisation project at (n) security (Note 1)
3	FY30	• Sub-transmission line constructed from North Otago GXP to Ngapara Zone Substation • Ngapara Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP • Enfield Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP • Low scenario - 5.3 MVA decarbonisation project at (n) security (Note 1)
4	FY33	• Convert 33 kV sub-transmission system to 110 kV (Note 2) • Supply Black Point GXP(NOIC) and Oamaru GXP from new North Otago GXP via 110 kV ring • Disconnect Black Point GXP and Oamaru GXP from Transpower's 110 kV transmission network • Remove Special Protection Scheme • Increase Oamaru GXP (n-1) limit to 60 MVA

Notes:

1. *Early conversations with our customer for the 5.3 MVA decarbonisation project indicate that they will be satisfied with a (n) security supply.*
2. *The FY32 project will free up significant capacity for use in the South Canterbury region and may allow Transpower to optimise their 110 kV transmission system. Based on our demand forecasts it is unlikely we would invest in this solution without a fair contribution from the other parties who will benefit.*

We provide further details on these projects in Section 6.8 Proposed Network Development Projects.

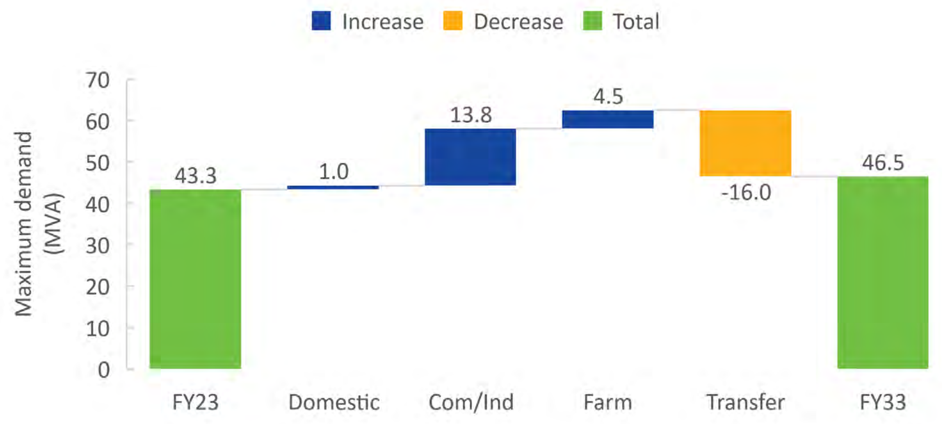


Figure 79 - Oamaru GXP demand growth components - expected scenario

Most of the demand growth to FY33 is from process heat decarbonisation (Com/Ind) followed by irrigation conversions (Farm) in the Lower Waitaki area.

Between FY24 and FY27, demand above 45 MVA will be subject to (n) security of supply until we construct the new North Otago GXP.

A large decarbonisation customer who may require 5.3 MVA between FY27 and FY30 has indicated their satisfaction with (n) level security of supply. This load would remain at (n) security until FY30 when we plan to transfer Ngapara and Enfield Zone Substations to the new North Otago GXP.

Table 61 - Oamaru GXP capacity and security summary

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
45 (n-1) 53 MVA (n)	A3	No interruption										

From FY23 we will connect new irrigation and large-load connections at (n) level GXP security. If there is a Transpower 110 kV line outage during a constrained period, (n) security demand will be shed via the Transpower Special Protection Scheme (we estimate the probability of this to be one event in 30 years). Once the constraint is alleviated, GXP security levels will increased to (n-1) for these customers.

6.5.3 Waitaki GXP

Configuration – One 25 MVA power transformer (NWL owned) and one 5.5 MVA power transformer (Transpower owned)

GXP security rating – 5.5 MVA (n-1), 25 MVA (n)

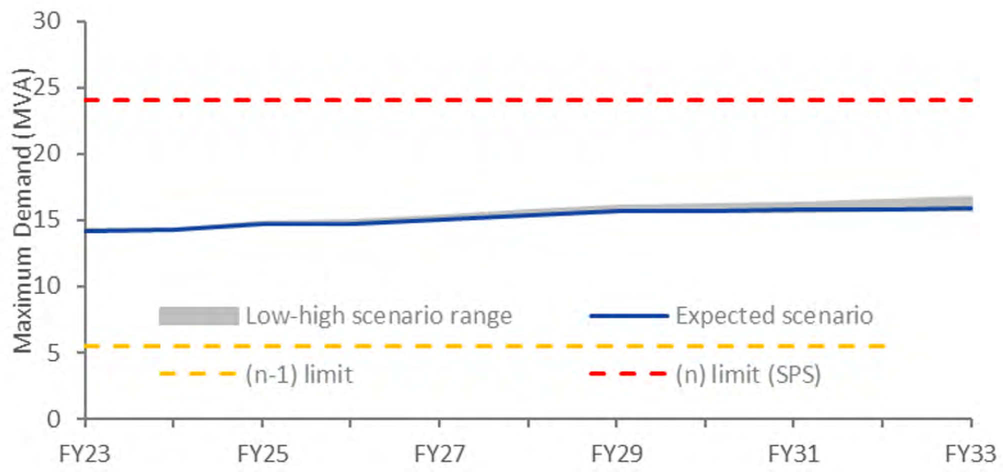


Figure 80 - Waitaki GXP demand growth scenarios

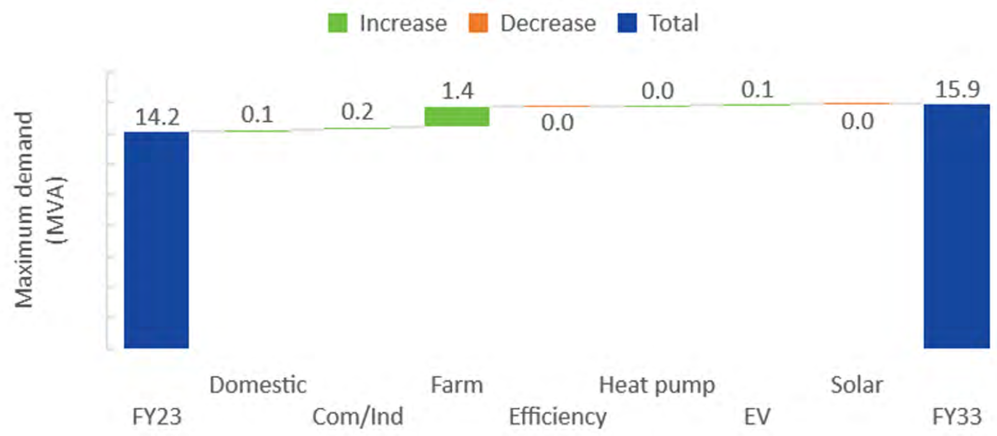


Figure 81 -Demand growth components – expected scenario

We expect low demand growth for the Waitaki GXP over the planning period. An allowance for irrigation expansion accounts for the bulk of this growth.

Table 62 - Waitaki GXP capacity and security summary

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
24	A3	50% in switching time 40% within 12 hours 10% in repair time										

There are no capacity constraints expected in the planning period.

If the 24 MVA transformer fails in FY23, we cannot currently provide sufficient backup security from the Waitaki 5.5 MVA transformer and Oamaru GXP (this risk applies to 0.8 MVA of demand for 14 hours in FY23). We have a project planned in FY24 which will allow an additional 3 MVA of backup capacity to be supplied from Twizel GXP, alleviating this security constraint. We provide further details on this project in **Section 6.8** Proposed Network Development Projects.

6.5.4 Twizel GXP

Configuration – Two 27 MVA power transformers

GXP security rating – (n-1)

Twizel GXP supplies Network Waitaki, Alpine Energy, and Meridian.

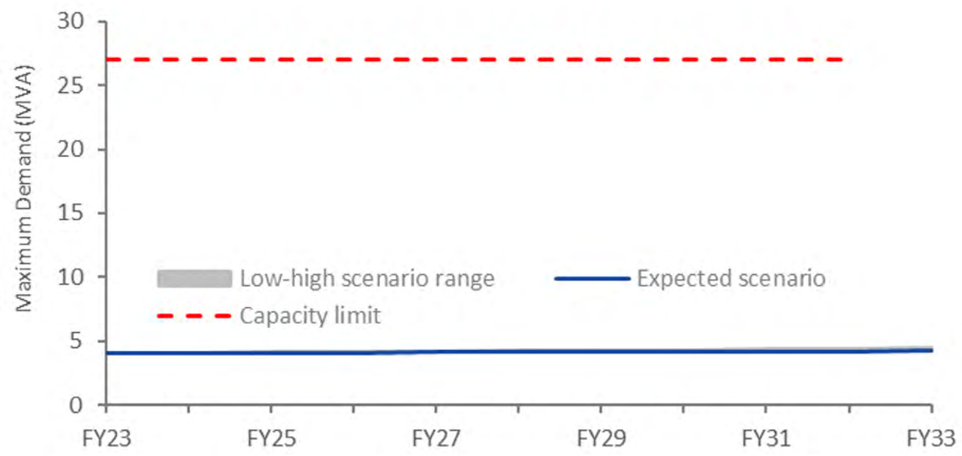


Figure 82 – Twizel GXP demand growth scenarios

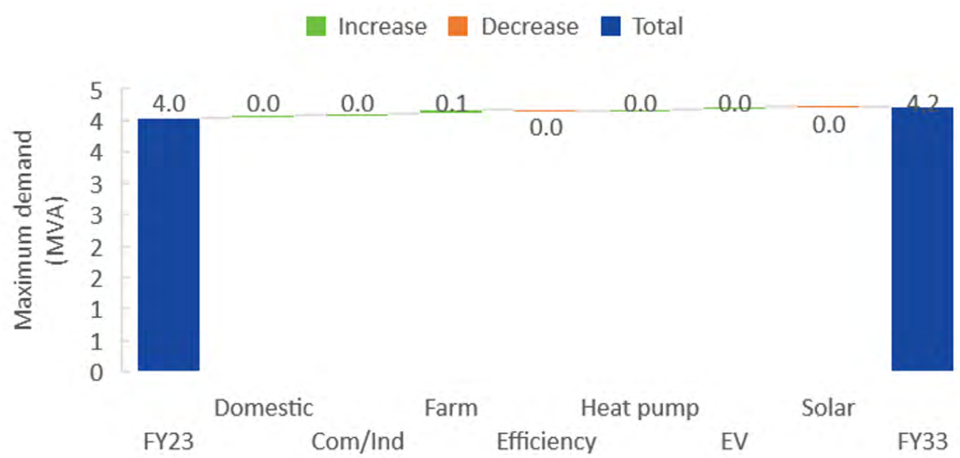


Figure 83 - Demand growth components – expected scenario

We expect low demand growth over the planning period.

Table 63 - Twizel GXP capacity and security summary

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
27	(n-1)	No interruption										

There are no capacity or security constraints expected in the planning period.

6.5.5 Black Point GXP

Configuration – Single 25 MVA power transformer

Security rating – (n) level security - customer substation

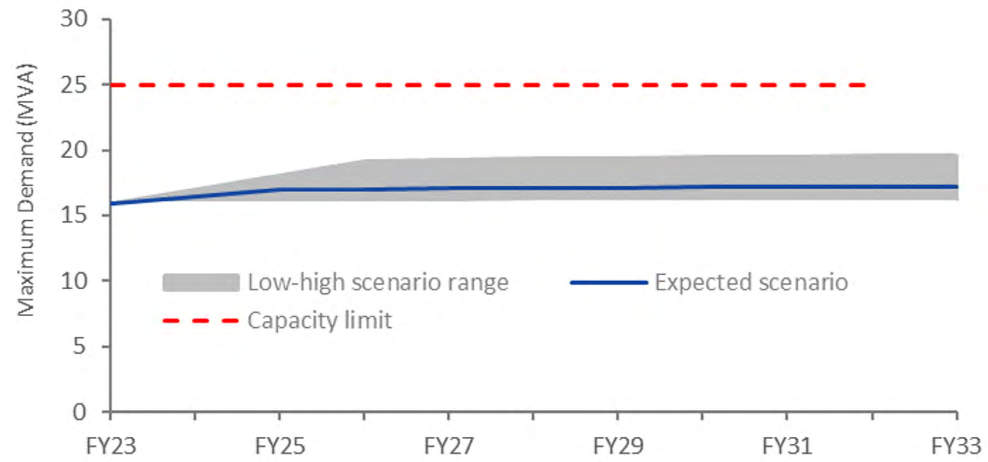


Figure 84 - Black Point GXP demand scenarios

NOIC are in the process of selling the remaining shares in their irrigation scheme, which will increase demand for water supply from the scheme. As a result, we expect maximum demand to increase to 17 MVA by FY26.

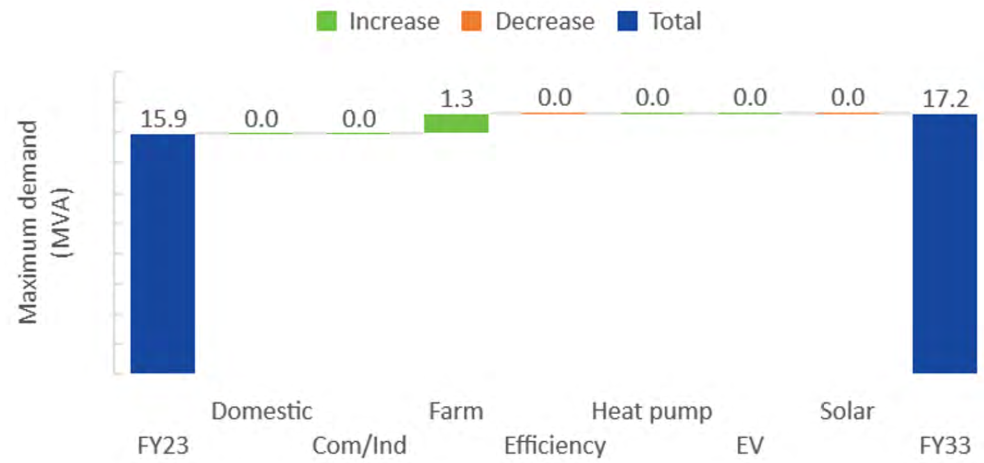


Figure 85 - Demand growth components – expected scenario

Table 64 - Black Point GXP capacity and security summary

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
25	(n)	Supply restored in repair time										

There are no capacity or security constraints expected in the planning period.

Note: This GXP is subject to a Transpower special protection (demand control) scheme. In the event of a fault on the Waitaki-Bells Pond-Oamaru 110 kV line during a constrained period, the special protection scheme may reduce NOIC pumping demand below the constraint.

6.5.6 North Otago GXP (proposed FY27)

FY27 Configuration – Dual 23 MVA 110/33 kV power transformers

Security rating – (n-1) level security

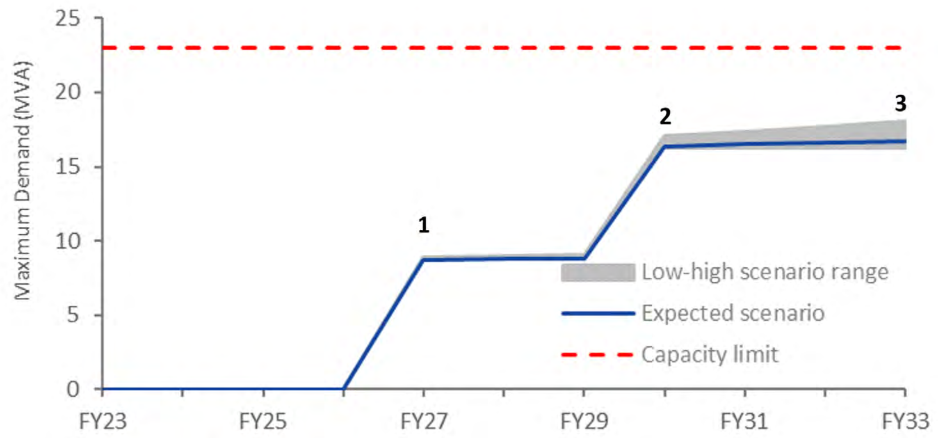


Figure 86 - North Otago GXP demand scenarios

Table 65 - Key events in demand scenarios

Marker	Period	Description
1	FY27	• North Otago GXP in service at 33 kV • Awamoko Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP • Papakaio Sub (5.3 MVA) transferred from Oamaru GXP to North Otago GXP
2	FY30	• Ngapara Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP • Enfield Sub (3.2 MVA) transferred from Oamaru GXP to North Otago GXP
3	FY32	• Convert 33 kV sub-transmission system to 110 kV (Note 2) • Supply Black Point GXP (NOIC) and Oamaru GXP from new North Otago GXP via 110 kV ring • Disconnect Black Point GXP+Oamaru GXP from Transpower's 110 kV transmission network

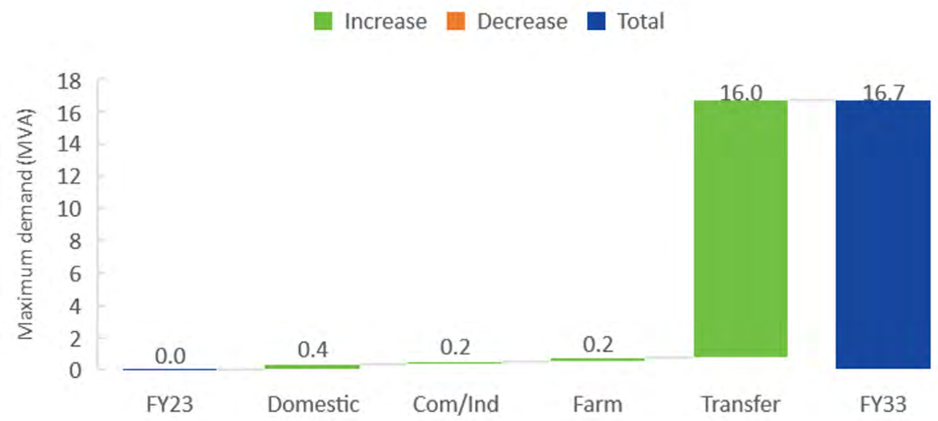


Figure 87 - Demand growth components – expected scenario

Table 66 - North Otago GXP capacity and security summary

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
23	(n-1)	No interruption										

There are no capacity or security constraints expected in the planning period.

6.6 Sub-Transmission and Substation Capacity and Security

6.6.1 Oamaru GXP supply area

Key	
Capacity & Security OK	
Security shortfall	
Capacity shortfall	
Not in service yet	

Figure 88 - Oamaru GXP sub-transmission and substations FY23

Table 67 - Oamaru GXP substations - capacity and security summary

Zone Substation	Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
				FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Awamoko	7	B4	100% restored in switching time			1		4					
Chelmer	28	B1	No interruption										
Enfield	7	B4	100% restored in switching time								5		
Five Forks	7	B4	100% restored in switching time										
Hampden	7	B4	100% restored in switching time										
Maheno	5	B4	100% restored in switching time										
Ngapara	7	B4	100% restored in switching time	2							5		
Papakaio	7	B4	100% restored in switching time	1				4					
Parsons	12	B4	100% restored in switching time										
Pukeuri	12	B2	No interruption		3								
Redcastle	15	B1	No interruption										

Comments: (See **Section 6.8** Network Development Projects for detail on projects and appendices for detailed zone substation analysis)

1. Awamoko and Papakaio Zone Sub security constraints are present until FY27 when the North Otago GXP is in service. (For a portion of the year, irrigation load on these substations may need to be shed for the duration of repair time for a failure on the section of overhead subtransmission line between Pukeuri and Papakaio)
2. A security shortfall for irrigation load at Ngapara will be present until FY25 when the Awamoko Sub is in service
3. Pukeuri security shortfall is present until FY26, when the power transformers are replaced with larger units (condition-based replacement)
4. We plan to transfer Awamoko and Papakaio Zone Subs to the North Otago GXP in FY27
5. We plan to be able to transfer Ngapara and Enfield Zone Subs to the North Otago GXP in FY30

6.6.2 Waitaki GXP supply area

Key

Capacity & Security OK	
Security shortfall	
Capacity shortfall	
Not in service yet	

Figure 89 - Waitaki GXP sub-transmission and substations FY23

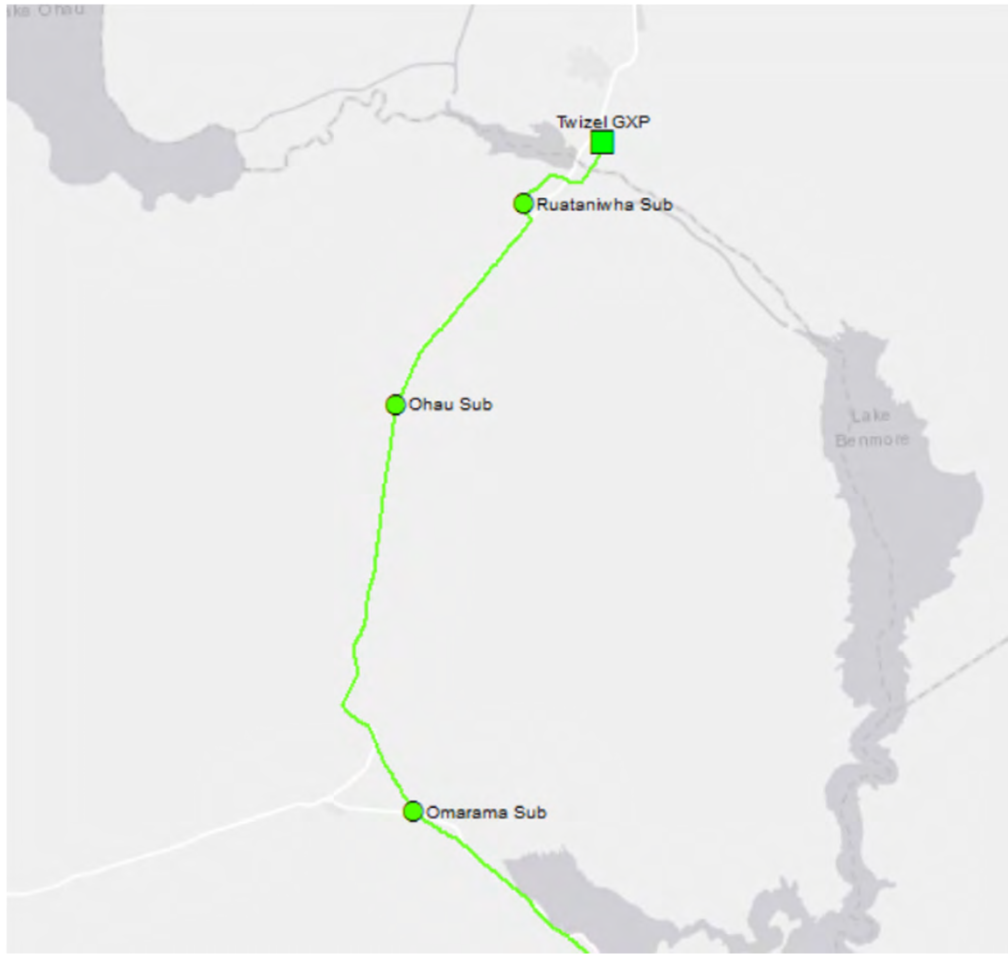
Table 68 - Zone substation capacity and security summary

Zone Substation	Capacity (MVA)	Security class	Service level for first sub-transmission or zone substation outage	Capacity and security summary									
				FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Duntroon	7	B4	100% restored in switching time								2		
Eastern	7	B4	100% restored in switching time										
Kurow	12	B4	100% restored in switching time										
Otematata	3	B4	100% restored in switching time	1									

Comments: (See Section 6.8 Network Development Projects for detail on projects and appendices for detailed zone substation analysis)

1. Otematata Zone Substation security shortfall will be alleviated by FY24
2. In FY30, Duntroon Zone Substation will be transferred to the new North Otago GXP

6.6.3 Twizel GXP supply area



Key

Capacity & Security OK	
Security shortfall	
Capacity shortfall	
Not in service yet	

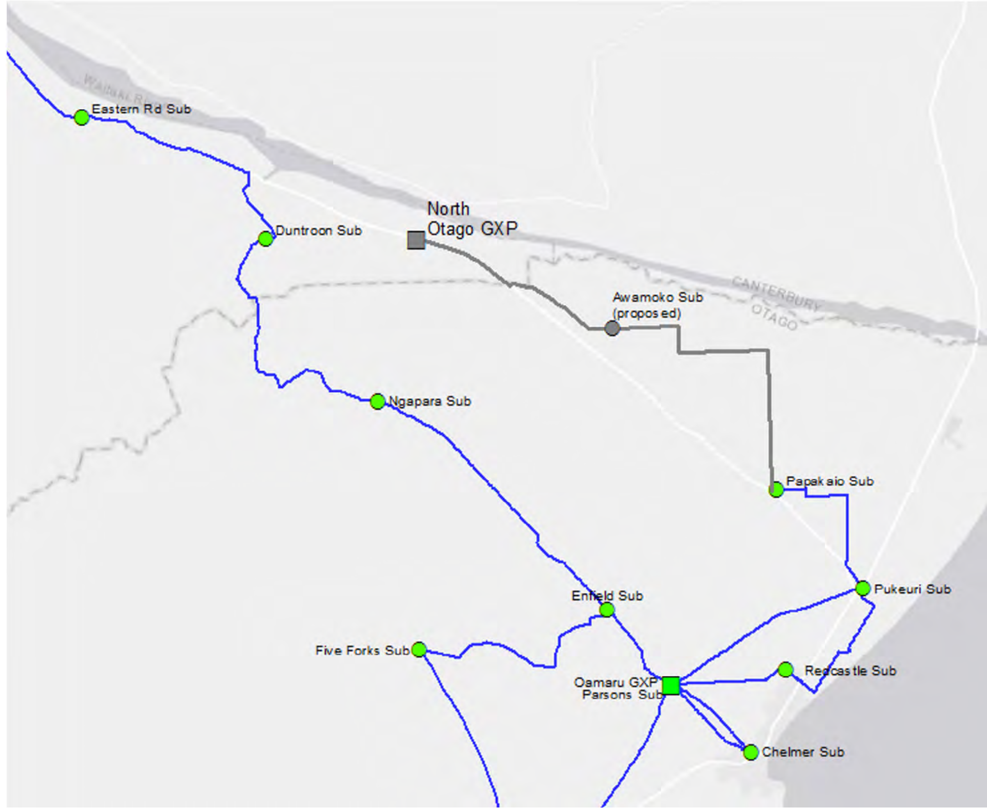
Figure 90 - Twizel GXP sub-transmission and substations FY23

Table 69 - Zone substation capacity and security summary

Zone Substation	Capacity (MVA)	Security class	Service level for first sub-transmission or zone substation outage	Capacity and security summary									
				FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Ohau	3	B4	100% restored in switching time										
Omarama	3	B4	100% restored in switching time										
Ruataniwha	2	B5	50% restored in switching time										

Comments: There are no capacity or security constraints expected before FY32

6.6.4 North Otago GXP supply area (FY27)



Key

Capacity & Security OK	
Security shortfall	
Capacity shortfall	
Not in service yet	

Figure 91 - North Otago GXP sub-transmission and substations

Table 70 - Zone substation capacity and security summary

Zone Substation	Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
				FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Awamoko	7	B4	100% restored in switching time					1					
Enfield	7	B4	100% restored in switching time								2		
Ngapara	7	B4	100% restored in switching time								2		
Papakaio	7	B4	100% restored in switching time					1					
Duntroon	7	B4	100% restored in switching time								2		

Comments: There are no capacity or security constraints expected before fy32

1. Awamoko and Papakaio zone subs will be transferred from Oamaru GXP in FY27
2. Enfield, Ngapara, and Duntroon zone subs will be transferred from Oamaru GXP in FY30

6.7 Distribution High Voltage Feeder - Capacity and Security

We have completed preliminary capacity and security studies for our high voltage feeders based on FY23 maximum demand. We are currently developing our demand forecasting model to feeder level and will extend this analysis to the end of the planning period for the 2024 Asset Management Plan. Of the 59 high voltage feeders on our network, we have identified 10 that may not meet our security standard.

Table 71 - Distribution high voltage feeder capacity and security summary

Feeder	Zone Substation	Total customers	Rated capacity (MVA)	Maximum demand (MVA)	Security service level
CB494 Otiake	Eastern Rd	58	3.8	1.1	
CB480 Hampden[10]	Hampden	587	3.8	1.0	
CB412 Station Peak	Kurow	95	3.8	1.3	
CB411 Kurow	Kurow	409	3.8	0.9	
CB490 Ohau	Ohau	100	2.3	0.8	
CB492 Ruataniwha	Ohau	20	1.5	0.9	
CB425 Benmore	Otematata	126	2.3	0.3	
CB426 Otematata	Otematata	404	2.3	0.5	
CB429 Horse Gully	Parsons	54	5.7	0.6	

We will conduct detailed analysis of the remaining security gaps in FY24 and will develop business cases for inclusion into the 2024 Asset Management Plan.

[10] CB480 Hampden supplies Moeraki township. We will produce a business case to evaluate options to increase the security to our Moeraki customers in Q1 FY24.

6.8 Proposed Network Development Projects

6.8.1 GXP projects

6.8.1.1 Oamaru GXP Special Protection Scheme

Project No	Project	Cost ($000)	Year	Category
6.8.1.1	Implement Special Protection Scheme	$350	FY24	System growth
Issue	We expect Oamaru GXP demand will exceed the (n-1) capacity in FY24 due to strong decarbonisation demand growth. The earliest a GXP level project can be in place is FY27, leaving a capacity shortfall from FY24 to FY27.			
Solution chosen	We are working with Transpower to implement a Special Protection Scheme (SPS) to increase capacity at Oamaru GXP from 45 MVA to 53 MVA, subject to load above 45 MVA being subject to (n) security. That is, if an outage occurs on one of the two transmission circuits supplying Oamaru GXP during a constrained period, the SPS will automatically reduce demand below 45 MVA.			
Comments	We are working with Transpower to develop this non-network solution to gain more capacity from these existing assets and Transpower have agreed to this solution as a temporary measure while we construct a new GXP. We will require this SPS scheme until we can resupply Oamaru GXP from the new North Otago GXP (expected to be FY33). Transmission-related work will be funded via a Transpower Works Agreement. This project is related to the work on our network to enable the SPS.			

6.8.1.2 North Otago Grid Exit Point (GXP) development

Project No	Project stages	Cost ($000)	Year	Category
6.8.1.2	Site establishment Integrate into sub-transmission system	$800 $6,000	FY24 FY27	System growth
Issue	We expect Oamaru GXP demand to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project has indicated they may require supply.			
Solution chosen	This project involves construction of a new 220/110/33 kV GXP in the Black Point area by FY27. Initially this GXP will bring supply into our 33 kV sub-transmission network and allow us to progressively offload Oamaru GXP as demand approaches Oamaru GXP rating.			
Comments / alternatives considered	We collaborated with an external consultant to peer review our demand scenarios and evaluate the options to solve this issue. We considered: • Reconductoring the existing transmission circuits • Grid-scale batteries to reduce demand peaks • Embedded renewable generation • Demand response • Grid bypass options. Building a new GXP in the Black Point area was clearly the best economic solution to provide future capacity and security for our customers. This project involves buying land, establishing 110 kV switchyard, 110/33 kV transformers and integration into the NWL sub-transmission system. The remaining GXP costs will be funded via a Transpower Works Agreement. The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP.			

6.8.2 Sub-transmission and substation projects

6.8.2.1 Awamoko Substation development

Project No	Projects	Cost ($000)	Year	Category
6.8.2.1	New Awamoko Zone Sub Sub-transmission line	2,340 5,250	FY24 FY24	System growth
Issue	Papakaio Zone Sub is approaching rated capacity and we expect this will be exceeded in FY25. In addition, voltages at the end of 11 kV feeders are approaching regulatory minimum and there is insufficient backup security available from neighbouring zone substations for a sub-transmission or substation outage.			
Solution chosen	We plan to install a new 10 MVA 33/11 kV zone substation in the Awamoko area. This will alleviate the capacity and security constraints at Papakaio Zone Sub (except for a sub-transmission outage between Pukeuri and Papakaio Zone Subs, which will be present until the North Otago GXP is in service in FY27), as well as security constraints at Ngapara Zone Sub. A new sub-transmission line will be constructed between Papakaio Zone Sub and the new Awamoko Zone Sub. We will operate this line at 33 kV until FY33, when we expect this will be reconfigured to form part of the 110 kV ring to supply Oamaru GXP from the new North Otago GXP.			
Comments/ alternatives considered	We evaluated the use of battery energy storage systems, embedded solar generation, diesel generation, demand response, targeted feeder upgrades, and installing a duplicate transformer at Papakaio Zone Sub. Only the chosen solution could alleviate the capacity, security, and voltage constraints.			

6.8.2.2 Otematata security of supply improvement

Project No	Project	Cost ($000)	Year	Category
6.8.2.2	Otematata security of supply improvement	$1,120	FY24	System growth
Issue	Otematata substation does not currently meet our security of supply standard due to lack of a reliable backup supply.			
Solution chosen	We plan to install a second transformer to increase security to appropriate levels.			
Comments/ alternatives considered	Options considered to provide the required security included: • taking a backup supply from Meridian at Benmore Power Station • a battery energy storage system • embedded solar • additional diesel generators • Use-of-demand response • an 11 kV line to tie to Omarama Zone Sub. The best economic option was to install a second transformer at Otematata Sub and keep the existing transformer as a backup unit.			

6.8.2.3 New sub-transmission line – Waitaki GXP to Kurow

Project No	Project	Cost ($000)	Year	Category
6.8.2.3	Sub-transmission line - Waitaki GXP to Kurow	$1,054	FY24	System growth
Issue	As Oamaru GXP demand increases between FY24 and FY27 (when the North Otago GXP will be in service), backup security available to Waitaki GXP customers will be reduced. If the Waitaki GXP 24 MVA transformer fails, we would need to employ rolling outages to irrigation load until we could repair or replace the transformer. Even though this is a low probability event, we evaluated the risk to our customers as unacceptable.			
Solution chosen	We plan to construct a second 3 km sub-transmission line from Waitaki GXP to Kurow to allow 3 MVA of backup security from Twizel GXP in parallel with 5.5 MVA from the backup Waitaki GXP transformer.			
Comments/ alternatives considered	We evaluated the use of battery energy storage systems, embedded solar generation, diesel generation, demand response, and duplicating the 24 MVA transformer at Waitaki GXP. We only require this solution until the new GXP is operational. The existing sub-transmission line between Waitaki GXP and Kurow is close to end of life and the solution chosen has the benefit of avoiding its rebuild.			

6.8.2.4 New sub-transmission line – North Otago GXP to Awamoko

Project No	Project stages	Cost ($000)	Year	Category
6.8.2.4	Design sub-transmission line Construct sub-transmission line	$200 $3,675	FY25 FY26	System growth
Issue	We are planning for the new Oamaru GXP to be in service by FY27. A new sub-transmission line is required so we can transfer Awamoko and Papakaio Zone Substations to the new GXP.			
Solution chosen	We plan to construct a new 110 kV sub-transmission line from the North Otago GXP to Awamoko Zone Sub. We will operate this line at 33 kV until FY33, when we expect to reconfigure it to form part of the 110 kV ring to supply Oamaru GXP from the new North Otago GXP.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP.			

6.8.2.5 New sub-transmission line – North Otago GXP to Ngapara

Project No	Project stages	Cost ($000)	Year	Category
6.8.2.5	Design sub-transmission line Construct sub-transmission line	$200 $4,900	FY28 FY28/29	System growth
Issue	We are planning for the new North Otago GXP to be in service by FY27. To allow Ngapara and Enfield Zone Substations to be transferred to this new GXP, a new sub-transmission line will be required.			
Solution chosen	We plan to construct a new sub-transmission line between North Otago GXP and Ngapara Zone Sub. We will operate this line at 33 kV until FY33 when we expect to reconfigure it to form part of the 110 kV ring to supply Oamaru GXP from the new North Otago GXP.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.6 New subtransmission line – Ngapara to Oamaru GXP

Project No	Project	Cost ($000)	Year	Category
6.8.2.6	Design sub-transmission line Construct sub-transmission line	$200 $8,750	FY30 FY31/32	System growth
Issue	We expect Oamaru GXP demand will exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	We plan to construct a new sub-transmission line between Ngapara Zone Sub and Oamaru GXP. We will operate this line at 33 kV until FY33 when we expect to reconfigure it to form part of the 110 kV ring to supply Oamaru GXP from the new North Otago GXP.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.7 Install conversion station near Ngapara

Project No	Project	Cost ($000)	Year	Category
6.8.2.7	Install conversion station near Ngapara	2,000	FY30-FY32	System growth
Issue	Oamaru GXP demand is forecast to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	Install a 110/33 kV transformer in the Ngapara area to convert between the 110 kV ring and the 33 kV sub-transmission circuit towards Duntroon.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.8 Convert Awamoko Zone Sub to 110/11 kV

Project No	Project	Cost ($000)	Year	Category
6.8.2.8	Convert Awamoko Zone Sub to 110/11 kV	1,500	FY33	System growth
Issue	Oamaru GXP demand is forecast to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	Convert Awamoko Zone Sub to 110/11 kV substation.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.9 Convert Papakaio Zone Sub to 110/11 kV

Project No	Project	Cost ($000)	Year	Category
6.8.2.9	Convert Papakaio Zone Sub to 110/11 kV	$1,500	FY33	System growth
Issue	Oamaru GXP demand is forecast to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	Convert Papakaio Zone Sub to 110/11 kV substation.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.10 Purchase Transpower 110 kV lines and Oamaru GXP

Project No	Project	Cost ($000)	Year	Category
6.8.2.10	Purchase Transpower 110 kV lines and Oamaru GXP	$6,500	FY33	System growth
Issue	Oamaru GXP demand is forecast to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	Purchase Transpower 110 kV lines between Glenavy and Oamaru GXP and Oamaru GXP assets.			
Comments/ alternatives considered	The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.11 Convert sub-transmission to 110 kV

Project No	Project	Cost ($000)	Year	Category
6.8.2.11	Convert sub-transmission to 110 kV	$2,000	FY33	System growth
Issue	Oamaru GXP demand is forecast to exceed the SPS rating of 53 MVA by FY27, when a large decarbonisation project is expected to require supply.			
Solution chosen	Disconnect Transpower lines at Glenavy. Connect into 110 kV circuits near Papakaio. Connect lines to 110 kV breakers at North Otago GXP.			
Comments/ alternatives considered	Conversion project to commission 110 kV ring from North Otago GXP to Oamaru GXP. The final business case is scheduled for Q2 FY23 once Transpower has completed final design and costing for the new North Otago GXP. We may be able to defer this project if the low growth scenario occurs.			

6.8.2.12 Weston-Pukeuri Sub-trans ring protection upgrade

Project No	Project	Cost ($000)	Year	Category
6.8.2.12	Weston- Pukeuri Sub-trans ring protection upgrade	$350	FY24	System growth
Issue	A recent unplanned outage on the Weston sub-transmission ring supplying Pukeuri, Redcastle and Papakaio Zone Subs highlighted shortcomings in the ring protection scheme.			
Solution chosen	Connection of fibre to protection devices will enable a more secure protection scheme.			
Comments/ alternatives considered	Further analysis and a business case are required.			

6.8.2.13 Weston-Maheno Sub-trans ring protection upgrade

Project No	Project	Cost ($000)	Year	Category
6.8.2.13	Weston-Maheno Sub-trans ring protection upgrade	$50 $300	FY24 FY25	System growth
Issue	A recent unplanned outage on the Weston sub-transmission ring supplying Maheno, Hampden, Five Forks and Enfield Zone Subs highlighted the shortcomings of an open ring protection scheme.			
Solution chosen	Reconfiguring protection devices, designing and installing closed ring protection scheme.			
Comments/ alternatives considered	Further analysis and a business case are required.			

6.8.3 Distribution projects

6.8.3.1 Woollen Mills HV feeder upgrade

Project No	Project	Cost ($000)	Year	Category
6.8.3.1	Woollen Mills HV feeder upgrade	$1,040 $140	FY23 FY24	System growth
Issue	There is insufficient capacity in the existing high voltage distribution feeder to a customer who has requested a new 3 MVA supply for a process heat decarbonisation project.			
Solution chosen	Extend the Woollen Mills feeder at Redcastle Zone Sub to the customer's premises and install HV Switchgear. Reconfigure network to make this an express feeder.			
Comments/ alternatives considered	There were limited other options available to supply this large load, which has a large energy requirement. This was the most economic option. Note: Most costs are scheduled to fall in FY23. FY24 expenditure is related to HV switchgear purchase.			

6.8.3.2 Oamaru Business Park distribution upgrade

Project No	Project	Cost ($000)	Year	Category
6.8.3.2	Oamaru Business Park distribution upgrade	$300	FY24	System growth
Issue	A customer has indicated they are likely to require a large connection at the Business Park in June FY24. The existing LV network does not have sufficient capacity for this new demand.			
Solution chosen	This will require installation of a new ring main unit and a new transformer.			
Comments/ alternatives considered	We will produce a business case when the connection is confirmed.			

6.8.3.3 Provisional reinforcement projects

Project No	Project	Cost ($000)	Year	Category
6.8.3.3	Provisional reinforcement projects	$100 $500	FY24 FY26-FY33	System growth
Issue	Provisional budget for reinforcement projects resulting from customer growth.			
Solution chosen	To be determined.			
Comments/ alternatives considered	We will produce business cases as required. As named projects are developed, this provisional budget will be reduced.			

6.8.3.4 Provisional network enhancement projects

Project No	Project	Cost ($000)	Year	Category
6.8..3.4	Provisional network enhancement projects	$300	FY26	System growth
Issue	Provisional budget for reliability enhancement projects.			
Solution chosen	To be determined.			
Comments/ alternatives considered	Business cases will be produced as required. As named projects are determined annual provisional budget will be reduced.			

6.8.3.5 The Junction Switching Station automation

Project No	Project	Cost ($000)	Year	Category
6.8.3.5	The Junction Switching Station automation	$80	FY25	System growth
Issue	In conjunction with the Holmes Hill project, this project will increase security to the area by providing automated switching and sectionalising of the circuit after a fault.			
Solution chosen	Replace the switching station with an automated Halo unit.			
Comments/ alternatives considered	We will produce a business case in FY24.			

6.8.3.6 Holmes Hill security improvement

Project No	Project	Cost ($000)	Year	Category
6.8.3.6	Holmes Hill security improvement	$400	FY25	System growth
Issue	Customer growth on a high voltage spur feeder from a recent subdivision in the Holmes Hill area has resulted in this feeder not meeting our security standard.			
Solution chosen	We made an allowance when the subdivision was designed to extend this spur feeder through the subdivision to create dual supplies into the subdivision.			
Comments/ alternatives considered	We will produce a business case in FY24.			

6.8.4 Customer connection project

6.8.4.1 Customer connections

Project No	Project	Cost ($000)	Year	Category
6.8.4.1	Customer connections	$1,509	FY24	Customer connection
Issue	When a customer requires a new supply, capital expenditure may be required for such things as a new service fuse box, new power line, or new transformer.			
Solution chosen	To be determined per connection.			
Comments	This provisional budget is based on the previous three-year average and is often matched by a capital contribution from the customer.			

6.8.5 Reliability, safety, and environment projects

6.8.5.1 Low voltage monitoring

Project No	Project	Cost ($000)	Year	Business Case stage
6.8.5.1	Low voltage monitoring	$250	FY24-FY28	TBC
Issue	We present our rationale for this project in Section 6.2 Network Evolution Roadmap.			
Solution chosen	In FY23 we commenced a pilot project to install and evaluate low voltage monitoring units.			
Comments	We will produce a business case for the FY24-FY28 project in Q4 FY23.			

6.8.5.2 Communications projects

Project No	Project	Cost ($000)	Year	Business Case stage
6.8.5.2	Fibre (Maheno-Five forks) Fibre (Enfield-Five forks) Fibre (Ngapara Duntroon) Fibre (Kurow Duntroon) Communications upgrade Purchase Transpower comms site	$303 $250 $300 $600 $100 $200	FY24 FY24 FY29 FY30 FY24-FY33 FY25	TBC
Issue	Modern high reliability protection and monitoring systems require low latency, secure communications.			
Solution chosen	Subject to our communications roadmap, we will install fibre or upgrade radio links between Zone Substations to enable modern protection systems.			
Comments	Business cases will be produced as required.			

6.9 Network Development Programme

Project No.	System level	Description	FY24 $(000)	FY25 $(000)	FY26 $(000)	FY27 $(000)	FY28 $(000)	FY29 $(000)	FY30 $(000)	FY31 $(000)	FY32 $(000)	FY33 $(000)	Total ($000)
System growth													
6.8.1.1	GXP	Oamaru GXP Special Protection Scheme	350										350
6.8.1.2	GXP	North Otago GXP - Site establishment		800									800
	GXP	North Otago GXP - Integration into network				6,000							6,000
6.8.2.1	Subtrans/ Substation	New Awamoko substation	2,340										2,340
	Subtrans/ Substation	Sub-transmission line - Papakaio to Awamoko	5,250										5,250
6.8.2.2	Subtrans/ Substation	Otematata security of supply improvement	1,120										1,120
6.8.2.3	Subtrans/ Substation	Sub-transmission line - Waitaki GXP to Kurow	1,054										1,054
6.8.2.4	Subtrans/ Substation	Sub-transmission line – North Otago GXP to Awamoko		200	3,675								3,875
6.8.2.5	Subtrans/ Substation	Sub-transmission line – North Otago GXP to Ngapara					200	2,450	2,450				5,100
6.8.2.6	Subtrans/ Substation	Sub-transmission line – Ngapara to Oamaru GXP							200	4,375	4,375		
6.8.2.7	Subtrans/ Substation	Install conversion station near Ngapara									2,000		2,000
6.8.2.8	Subtrans/ Substation	Convert Awamoko Zone Sub to 110/11 kV										1,500	1,500
6.8.2.9	Subtrans/ Substation	Convert Papakaio Zone Sub to 110/11 kV										2,000	2,000
6.8.2.10	Subtrans/ Substation	Purchase Transpower 110 kV lines and Oamaru GXP										6,500	6,500
6.8.2.11	Subtrans/ Substation	Convert sub-transmission to 110 kV										2,000	2,000
6.8.2.12	Subtrans/ Substation	Weston- Pukeuri Subtrans ring protection upgrade	175	175									350
6.8.2.13	Subtrans/ Substation	Weston-Maheno Subtrans ring protection upgrade		300									300
6.8.3.1	Distribution	Woollen Mills HV feeder upgrade - switchgear	140										140
6.8.3.2	Distribution	Oamaru Business Park distribution upgrade	300										300
6.8.3.3	Distribution	Provisional reinforcement projects	100	500	500	500	500	500	600	700	800	90	4,790
6.8.3.4	Distribution	Provisional network enhancement projects				300	300	300	400	400	500	500	2,700
6.8.3.5	Distribution	The Junction switching station automation		80									80
6.8.3.6	Distribution	Holmes Hill security improvement		400									400
		Total System Growth	10,829	2,455	4,175	6,800	1,000	3,250	3,650	5,475	7,675	12,590	57,899

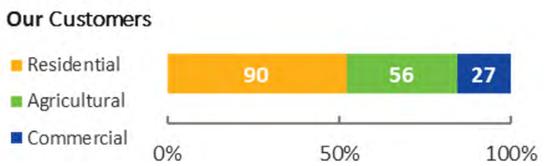
Project No.	System level	Description	FY24 $(000)	FY25 $(000)	FY26 $(000)	FY27 $(000)	FY28 $(000)	FY29 $(000)	FY30 $(000)	FY31 $(000)	FY32 $(000)	FY33 $(000)	Total ($000)
Consumer connection													
6.8.4.1	Distribution	New LV Service Connections	514	514	514	514	514	514	514	514	514	514	5,137
	Distribution	Install Distribution Transformers - Customers	356	356	356	356	356	356	356	356	356	356	3,564
	Distribution	New 11kV Network Extensions	438	438	438	438	438	438	438	438	438	438	4,381
	Distribution	Residential Subdivisions	201	201	201	201	201	201	201	201	201	201	2,007
		Total Consumer Connection	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	15,090
Reliability Safety and Environment													
6.8.5.1	Distribution	Low voltage monitoring	250	250	250	250	250						1,250
6.8.5.2	Other	Fibre (Maheno-Five forks)	303										303
	Other	Fibre (Enfield-Five forks)	250										250
	Other	Fibre (Ngapara Duntroon)						300					300
	Other	Fibre (Kurow Duntroon)							600				600
	Other	Radio link upgrade	50	100	100	100	100	100	100	100	100	100	950
	Other	Communications upgrades	100	100	100	100	100	100	100	100	100	100	1,000
	Other	Purchase Transpower Station Peak site		200									200
		Total Reliability Safety and Environment	953	650	450	450	450	500	800	200	200	200	4,853
		Grand total	13,291	4,614	6,134	8,759	2,959	5,259	5,959	7,184	9,384	14,299	77,841

6.9.1 Zone substations

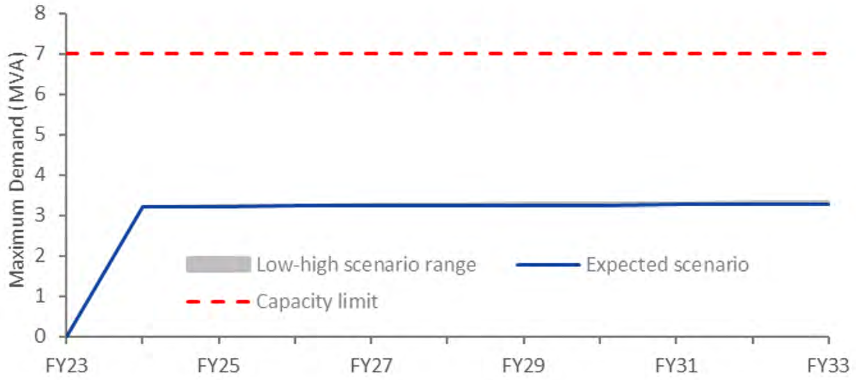
6.9.1.1 Awamoko Zone Substation

Configuration – Single 7 MVA power transformer

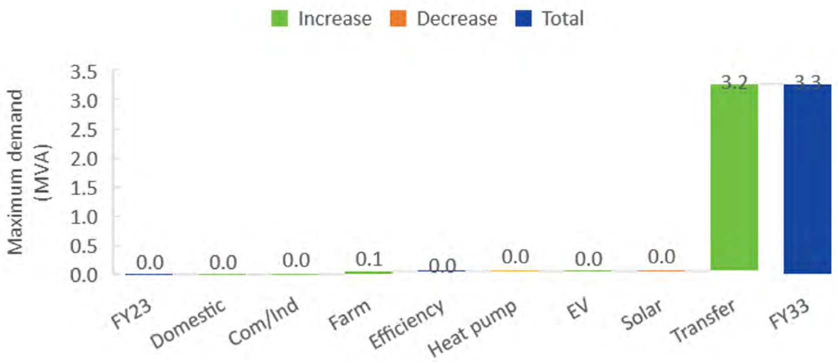
Security rating – B4 rural zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Sub-transmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

Commentary:

Awamoko Zone Substation is scheduled to be in service in FY24 and will reduce demand and provide security to Papakaio and Ngapara Zone Substations.

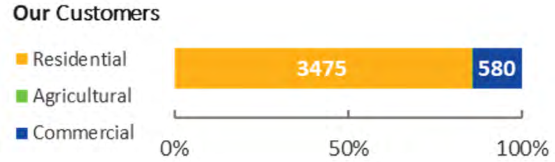
A security constraint for a subtransmission outage between Pukeuri and Papakaio Zone Substations until FY27 when the new North Otago GXP is in service.

No further capacity or security constraints are expected in the planning period.

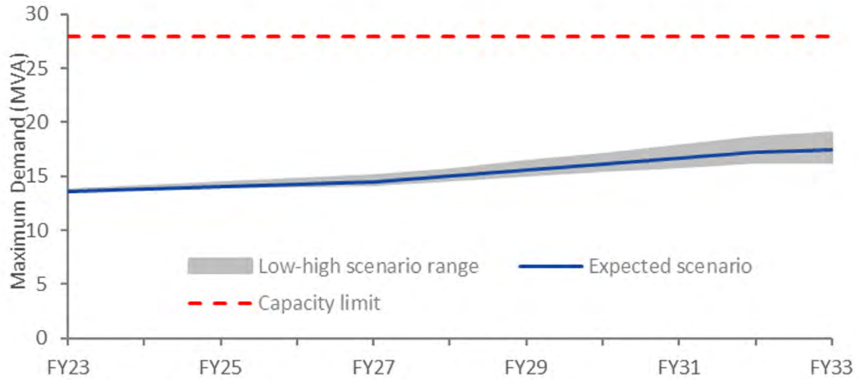
6.9.1.2 Chelmer Zone Substation

Configuration – Dual 28 MVA power transformers

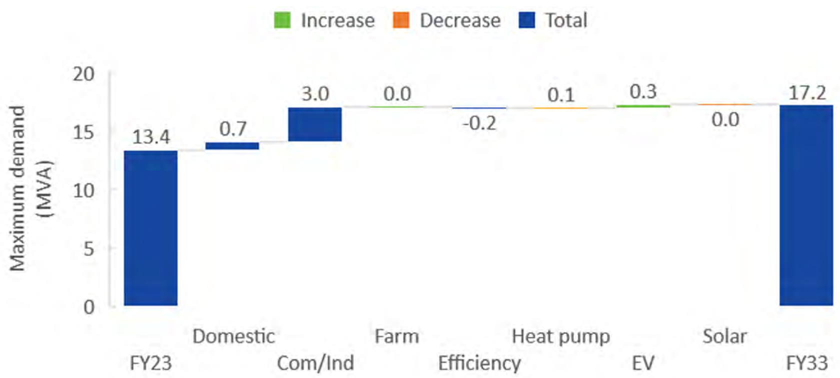
Security rating – B1 urban hub zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	No interruption (except for N security load)	-	-			
Zone substation	No interruption (except for N security load)	-	-			
Main HV feeders	All customers restored in switching time	60	-			
HV spur feeders	All customers restored in repair time	-	8			

Commentary:

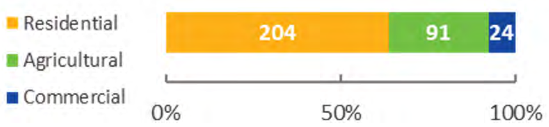
Chelmer Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

6.9.1.3 Enfield Zone Substation

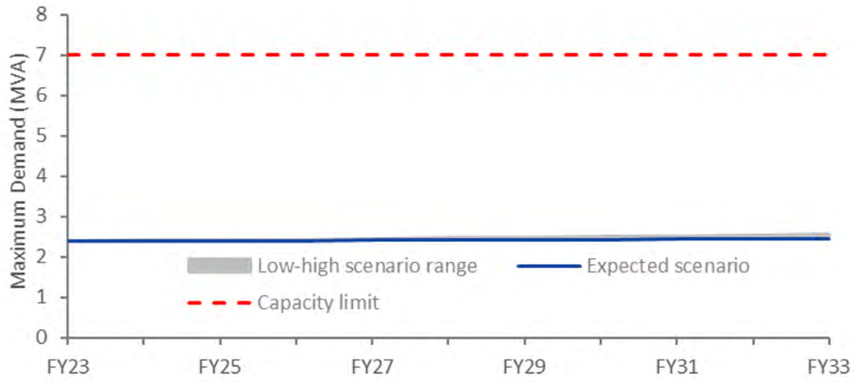
Configuration – Single 7 MVA power transformer

Security rating – B4 rural zone substation

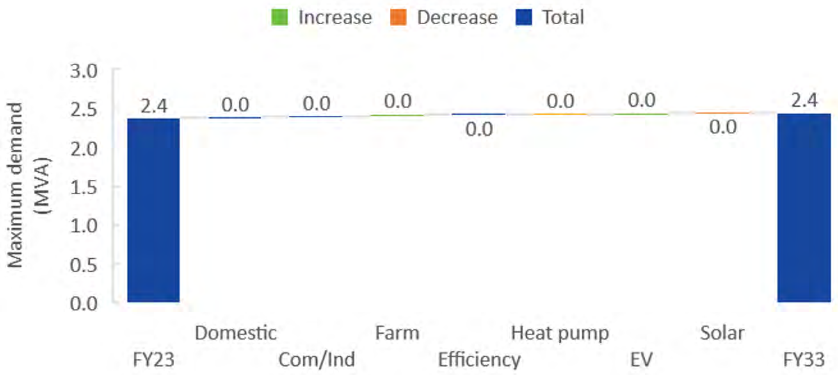
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

Commentary:

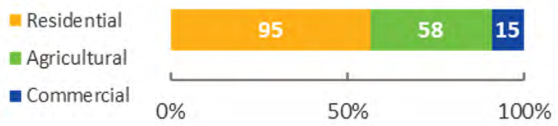
Enfield Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

6.9.1.4 Five Forks Zone Substation

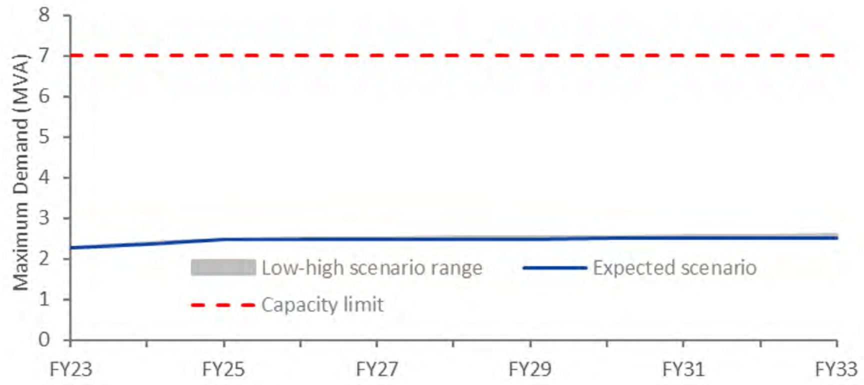
Configuration – Single 7 MVA power transformer

Security rating – B4 rural zone substation

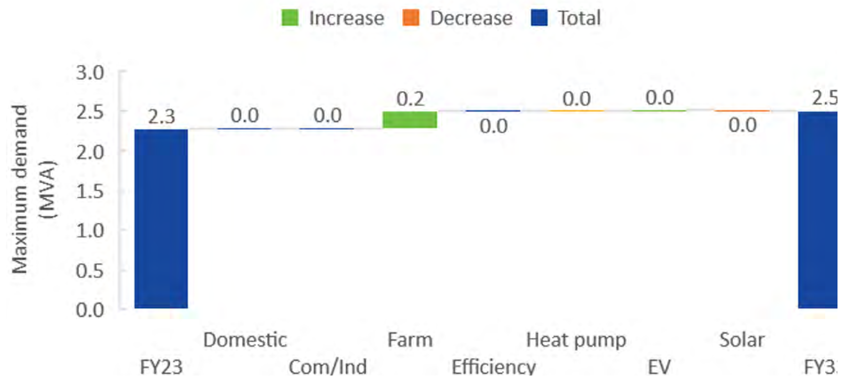
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

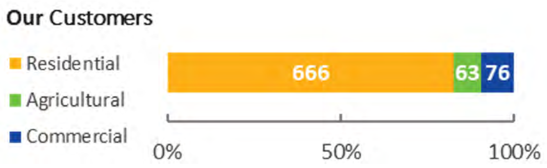
Commentary:

Five Forks Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

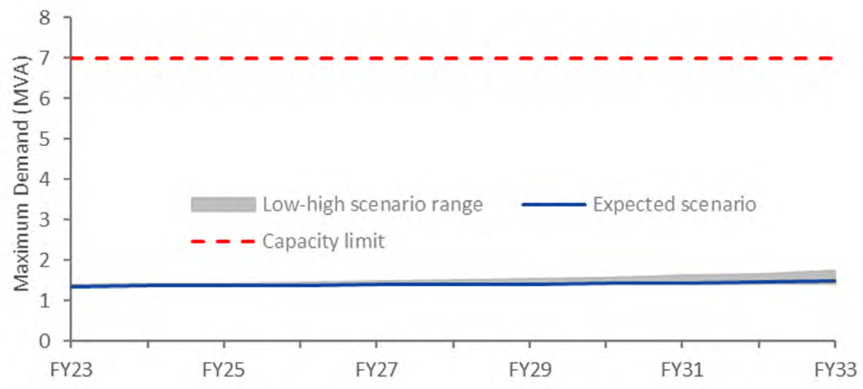
6.9.1.5 Hampden Zone Substation

Configuration – Single 7 MVA power transformer

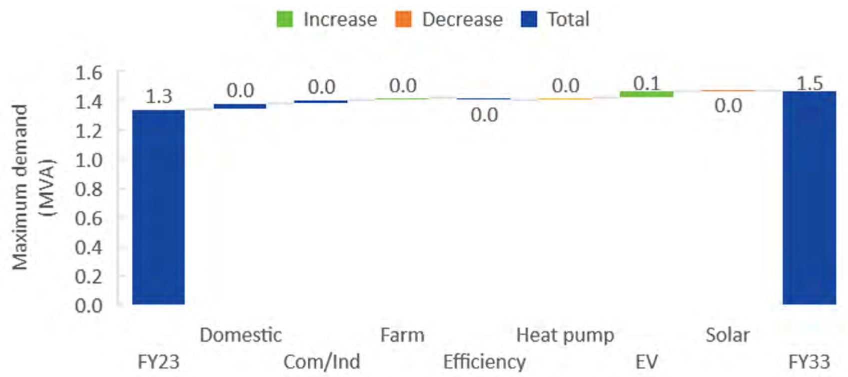
Security rating – B3 township zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

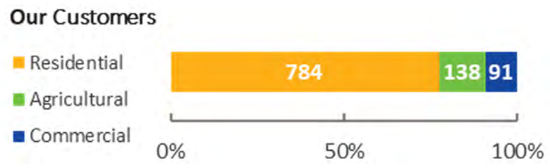
Commentary:

Hampden Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period except for Hampden feeder, where we cannot resupply 50% of customers in switching time. We will investigate options to solve this constraint and produce a business case for inclusion into the 2024 Asset Management Plan.

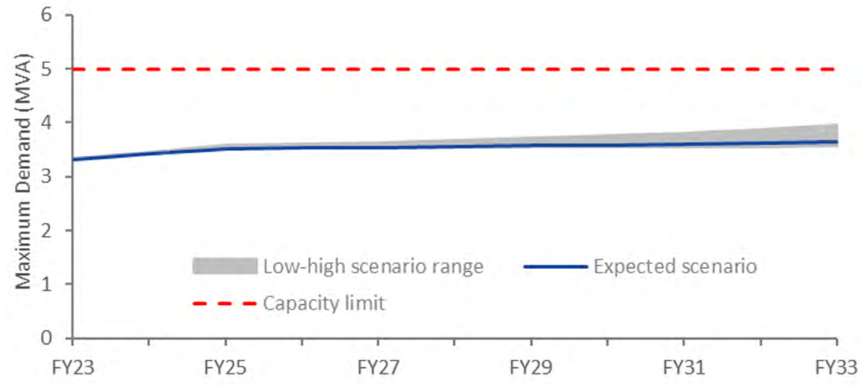
6.9.1.6 Maheno Zone Substation

Configuration – Single 5 MVA power transformer

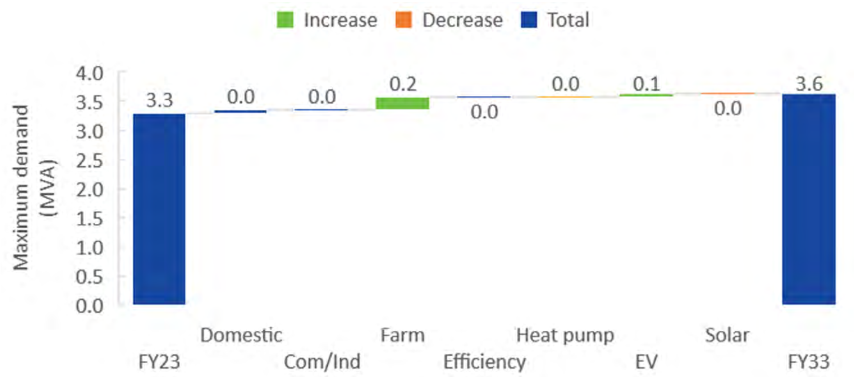
Security rating – B3 township zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

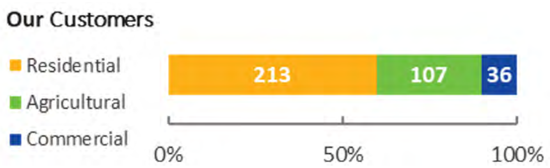
Commentary:

Maheno Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

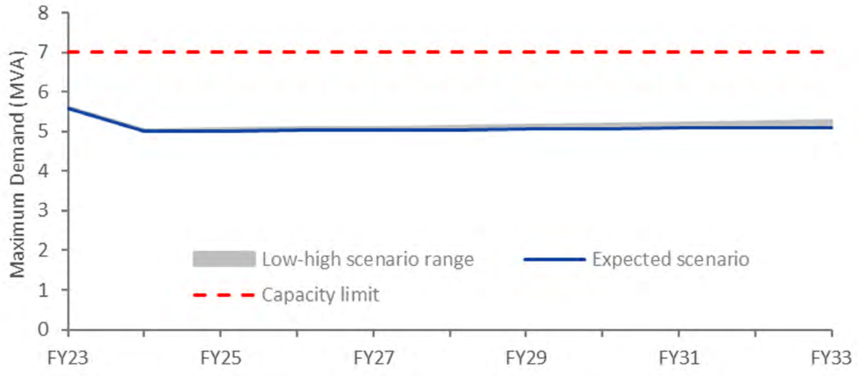
6.9.1.7 Ngapara Zone Substation

Configuration – Single 7 MVA power transformer

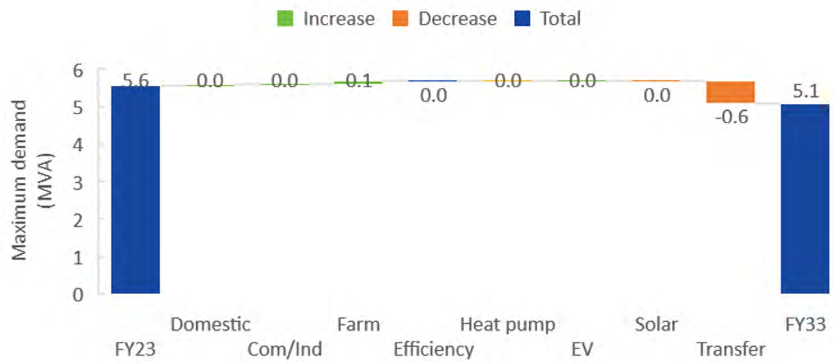
Security rating – B4 rural zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

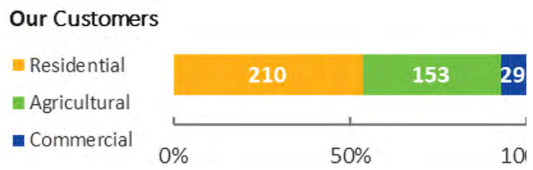
Commentary:

Ngapara Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard after FY24, when the new Awamoko Zone Substation is in service.

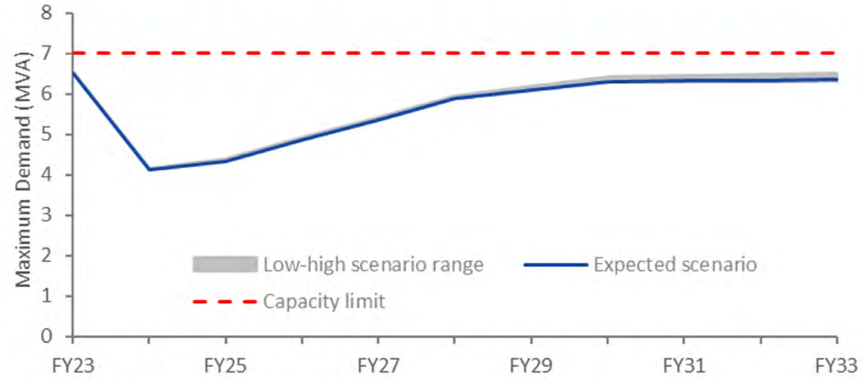
6.9.1.8 Papakaio Zone Substation

Configuration – Single 5 MVA power transformer

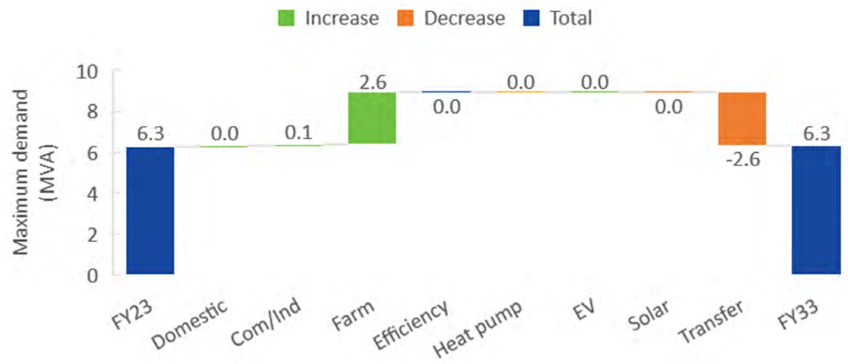
Security rating – B4 rural zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

Commentary:

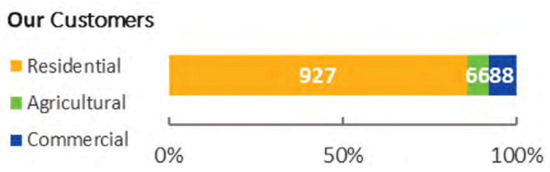
Papakaio Zone Substation has sufficient capacity to meet all demand scenarios.

The FY23 security of supply constraint will be alleviated in FY24 when Awamoko Zone Sub is in service, except for a sub-transmission outage between Pukeuri and Papakaio Zone Subs. This constraint will be alleviated in FY27, when the new North Otago GXP is in service.

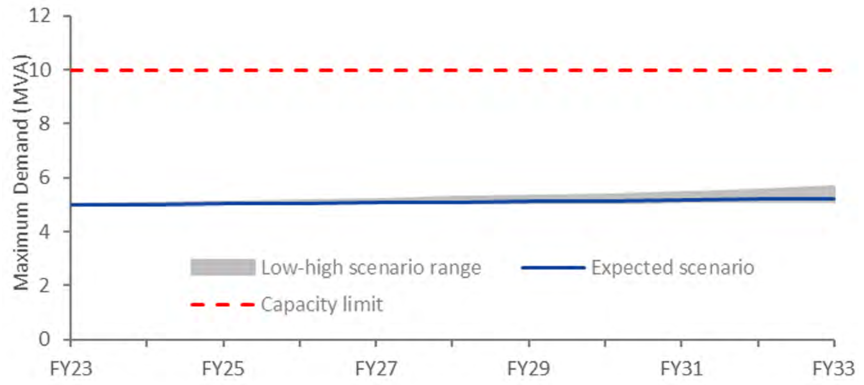
6.9.1.9 Parsons Zone Substation

Configuration – Single 12 MVA power transformer

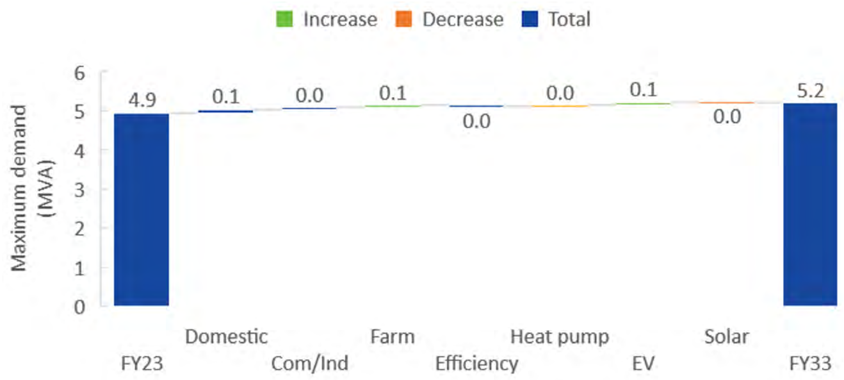
Security rating – B2 urban zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	No interruption (except for N security load)	-	-			
Zone substation	No interruption (except for N security load)	-	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	45	8			
HV spur feeders	All customers restored in repair time	-	8			

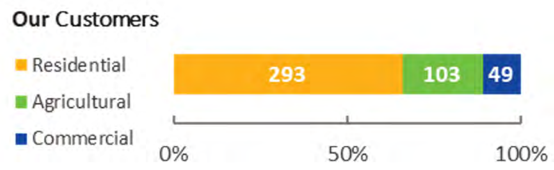
Commentary:

Parsons Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period except for the Horse Gully feeder, where we cannot supply 50% of customers in switching time. We will look at options to solve this constraint and produce a business case for the 2024 Asset Management Plan.

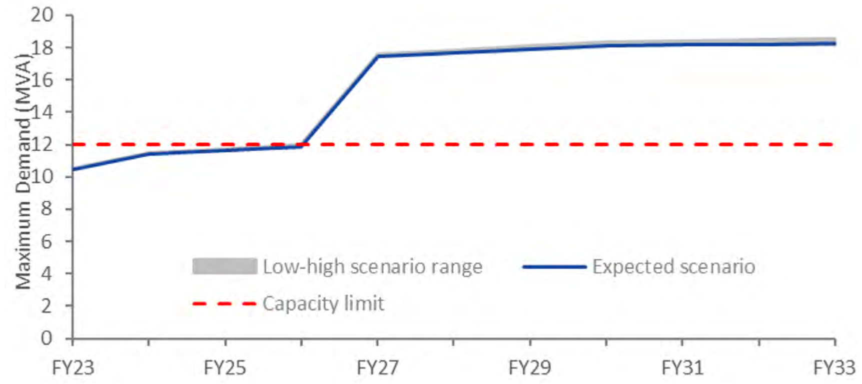
6.9.1.10 Pukeuri Zone Substation

Configuration – Dual 12 MVA power transformers

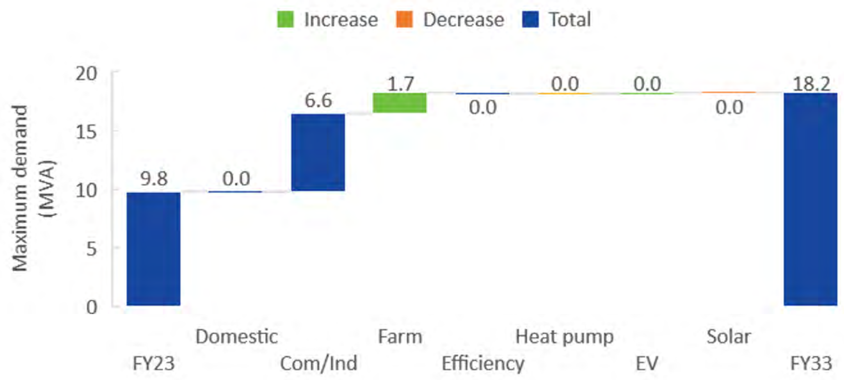
Security rating – B3 townshipl zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

Commentary: Pukeuri Zone Substation is expected to exceed the (n-1) rating of the transformers in FY27, when a large decarbonisation load is expected to take supply.

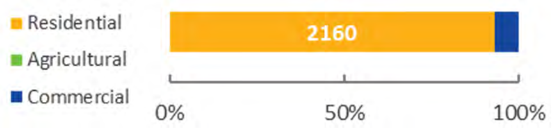
The two Pukeuri power transformers are scheduled for condition-based replacement in FY26. We will take the opportunity to install larger rated transformers (transformer ratings will be confirmed once we understand our customers decarbonisation load requirements).

6.9.1.11 Redcastle Zone Substation

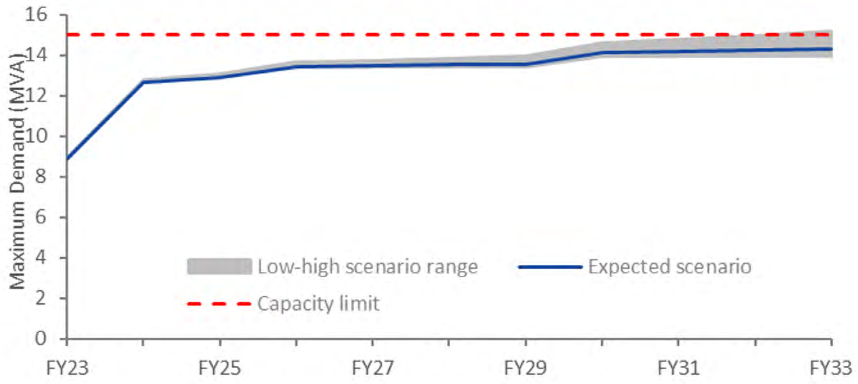
Configuration – Dual 15 MVA power transformers

Security rating – B1 urban zone substation

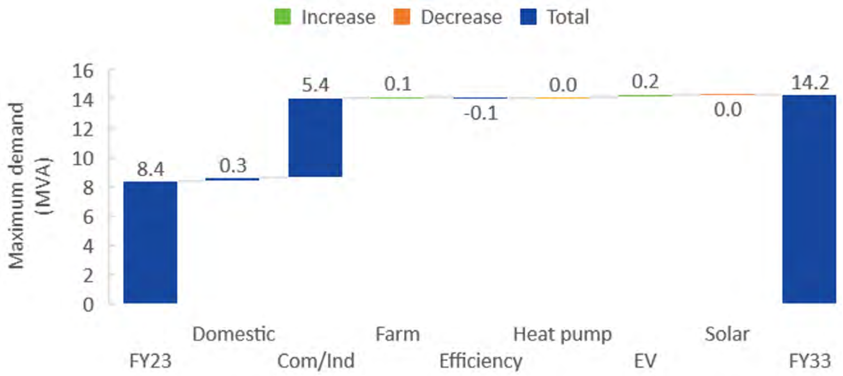
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	No interruption (except for N security load)	-	-			
Zone substation	No interruption (except for N security load)	-	-			
Main HV feeders	All customers restored in switching time	15	-			
HV spur feeders	All customers restored in repair time	-	8			

Commentary: Redcastle Zone Substation has sufficient capacity to meet expected demand scenarios and will meet our security of supply standard for the expected scenario over the planning period

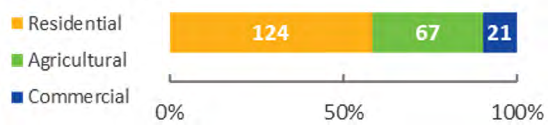
Under the high growth scenario, the (n-1) rating is exceeded in FY32. We will monitor actual load growth over the first half of the planning period and, if required, evaluate options to solve the capacity constraint.

6.9.1.12 Duntroon Zone Substation

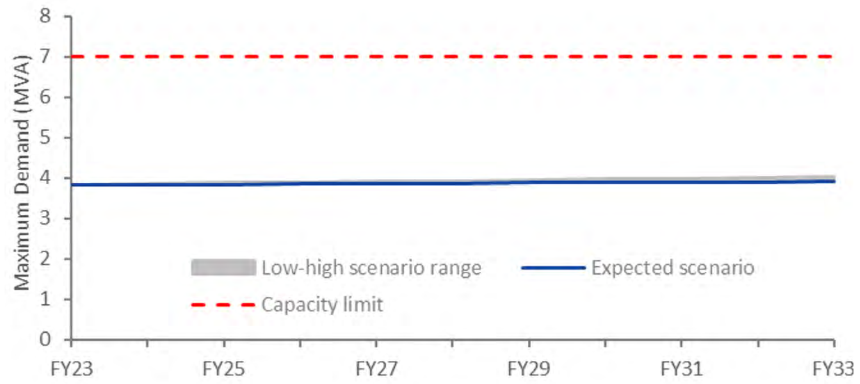
Configuration – Single 7 MVA power transformer

Security rating – B3 township zone substation

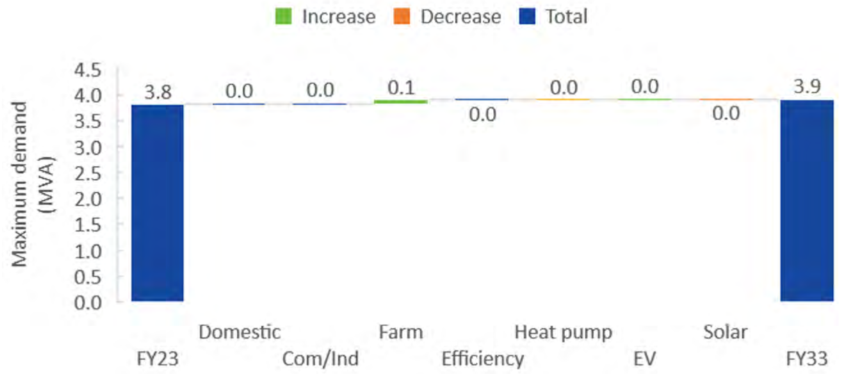
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

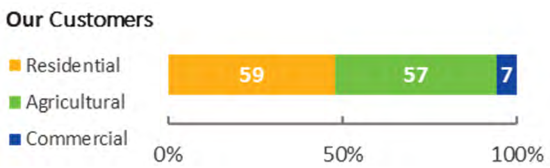
Commentary:

Duntroon Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

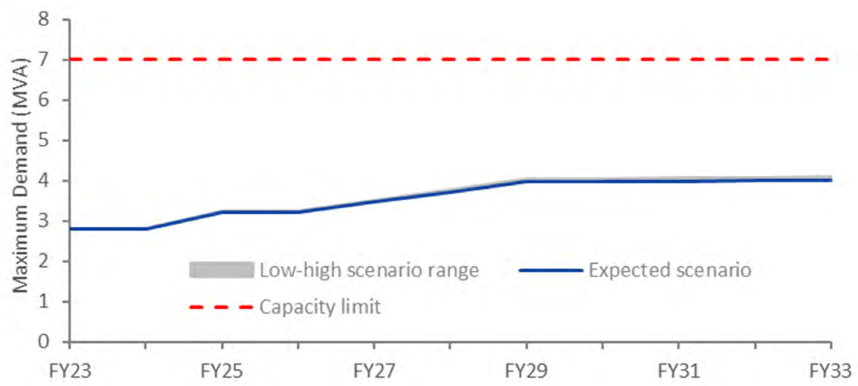
6.9.1.13 Eastern Road Zone Substation

Configuration – Single 7 MVA power transformer

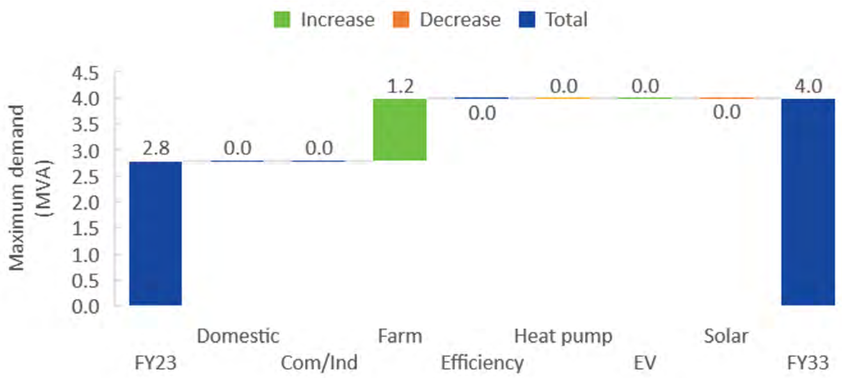
Security rating – B4 rural zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	105	10			
HV spur feeders	All customers restored in repair time	-	10			

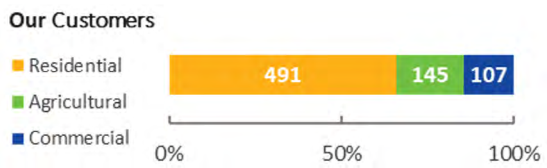
Commentary:

Eastern Road Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period except for the Otiake feeder – we cannot restore 50% of customers in a feeder outage. We will look at options to solve this constraint and produce a business case for the 2024 Asset Management Plan.

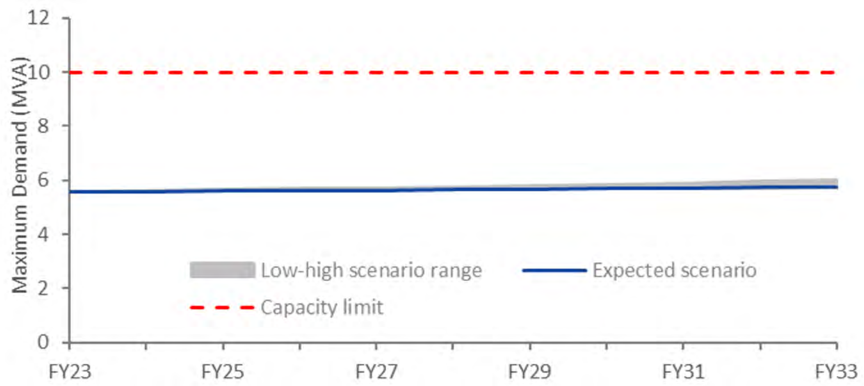
6.9.1.14 Kurow Zone Substation

Configuration – 15 MVA & 12 MVA power transformers

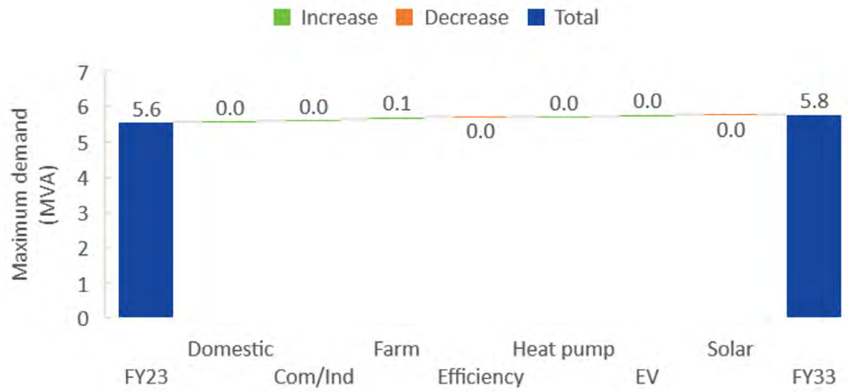
Security rating – B2 urban zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	No interruption	-	-			
Zone substation	No interruption	-	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	45	8			
HV spur feeders	All customers restored in repair time	-	8			

Commentary: Kurow Zone Substation has sufficient capacity to meet all demand scenarios.

There is a security shortfall in FY23 for an outage on the Waitaki GXP or sub-transmission line, which will be alleviated when the second transmission line is built from Waitaki GXP to Kurow in FY24.

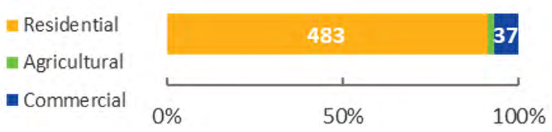
There is also a security shortfall for the Kurow and Station Peak feeders – we cannot restore 50% of customers in switching time for a feeder outage. We will look at options to solve this constraint and produce a business case for the 2024 Asset Management Plan.

6.9.1.15 Otematata Zone Substation

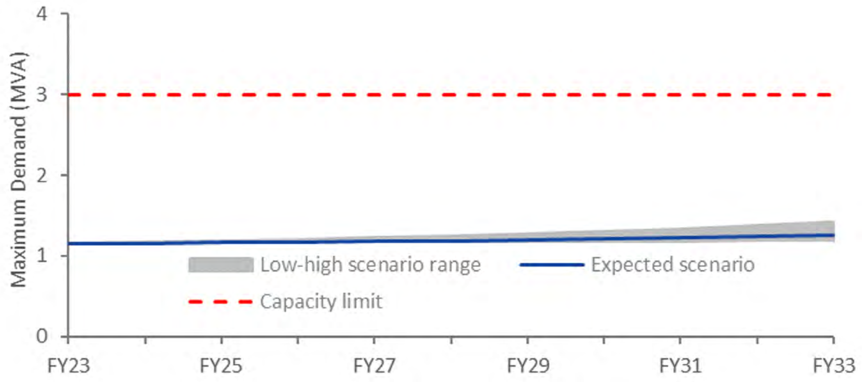
Configuration – Single 3 MVA power transformer

Security rating – B3 township zone substation

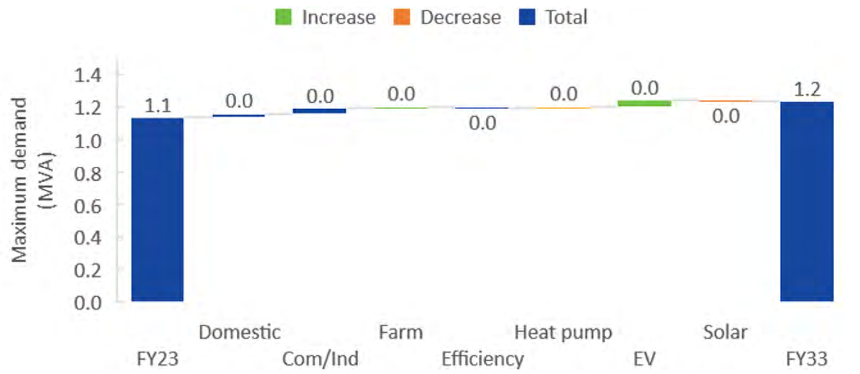
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

Commentary: Otematata Zone Substation has sufficient capacity to supply forecast demand for the remainder of the planning period.

There is a security shortfall for a Zone Substation outage, which will be alleviated in FY24 when a second transformer is planned to be installed.

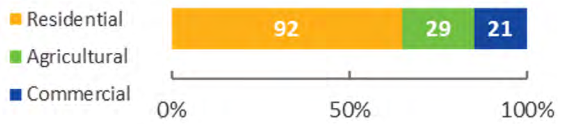
There is also a security shortfall on the Benmore and Otematata feeders. We will evaluate options to solve this constraint and produce a business case for the 2024 Asset Management Plan.

6.9.1.16 Ohau Zone Substation

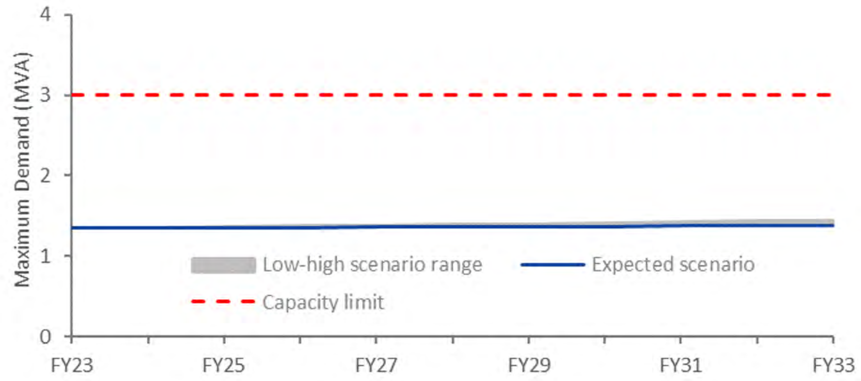
Configuration – Single 3 MVA power transformer

Security rating – B5 remote rural zone substation

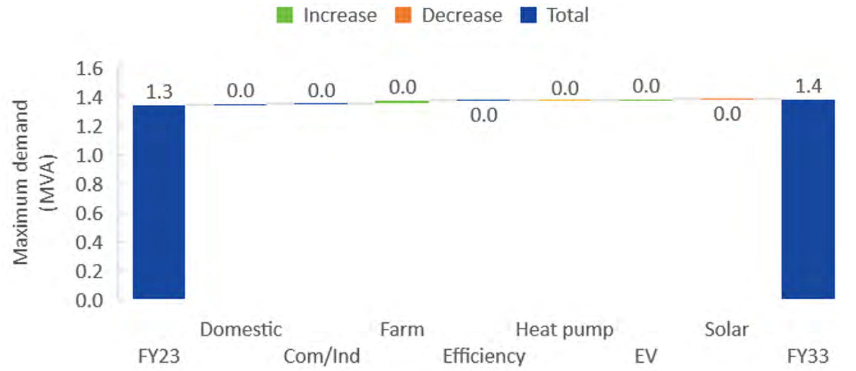
Our Customers



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	50% of customers in switching time, 50% in repair time	15	-			
Zone substation	50% of customers in switching time, 50% in repair time	15	-			
Main HV feeders	All customers restored in repair time	225	11			
HV spur feeders	All customers restored in repair time	-	11			

Commentary:

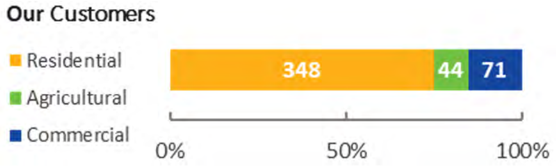
Ohau Zone Substation has sufficient capacity to meet all demand scenarios.

There is a security shortfall for the Ohau and Ruataniwha feeders – we cannot restore 50% of customers in switching time for a feeder outage. We will look at options to solve this constraint and produce a business case for the 2024 Asset Management Plan.

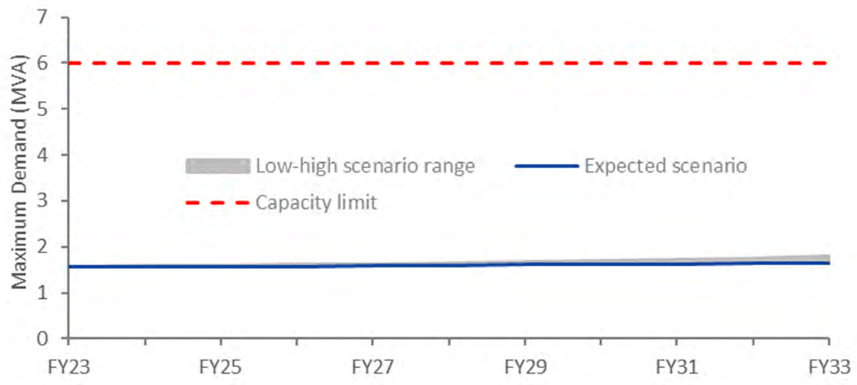
6.9.1.17 Omarama Zone Substation

Configuration – Dual 3 MVA power transformers

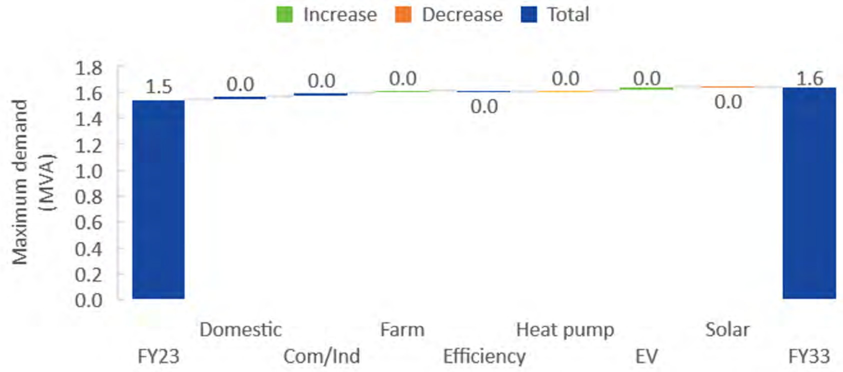
Security rating – B3 township zone substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	All customers restored in switching time	15	-			
Zone substation	All customers restored in switching time	15	-			
Main HV feeders	50% of customers in switching time, 50% in repair time	90	9			
HV spur feeders	All customers restored in repair time	-	9			

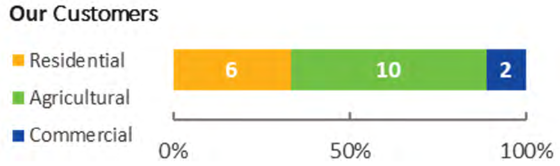
Commentary:

Omarama Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

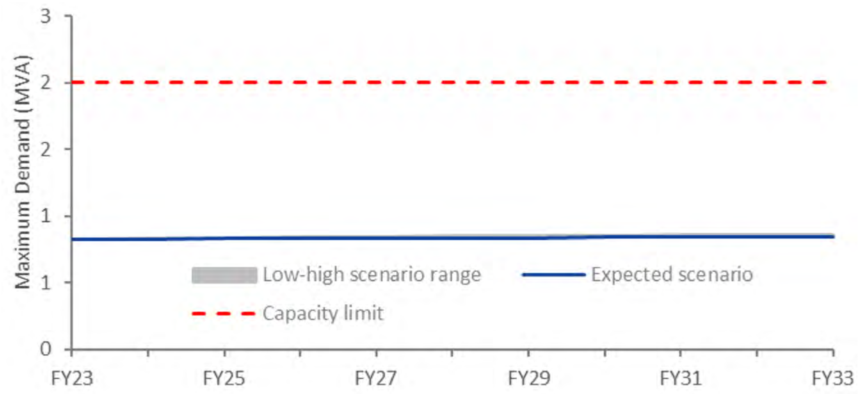
6.9.1.18 Ruataniwha Zone Substation

Configuration – Single 2 MVA power transformer

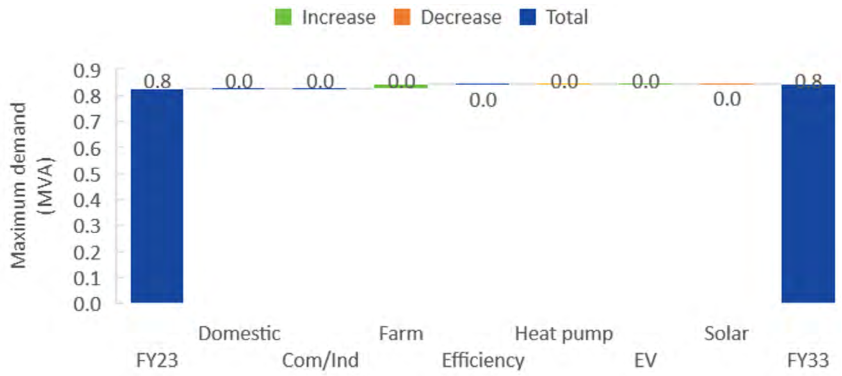
Security rating – (n) security customer substation



Demand forecast



New demand breakdown (expected scenario)



Security of supply summary (expected scenario)

Outage level	Service level (for a single outage)	Switching time target (mins)	Repair time target (hrs)	FY23	FY28	FY33
Subtransmission	100% in switching time	15	-			
Zone substation	All customers restored in repair time	15	-			
Main HV feeders	All customers restored in repair time	225	11			
HV spur feeders	All customers restored in repair time	-	11			

Commentary:

Ruataniwha Customer Substation has sufficient capacity to meet all demand scenarios and meets our customers' security requirements over the planning period. In the event of a prolonged zone substation outage, we can install a short section of 11 kV line to supply this customer from a feeder on our Ohau Zone Substation.

Non-Network Investment Plan

07 Non-Network Investment Plan

This chapter sets out our Non-Network Investment Plan.

7.1 Five Year Forecast

Table 71 - Five Year Forecast

Component	FY24 ($000)	FY25 ($000)	FY26 ($000)	FY27 ($000)	FY28 ($000)
Buildings	2,737	3,088	2,071	685	-
Vehicles	60	-	58	-	-
Communications Upgrades	100	100	-	-	-
Information Technology	100	100	100	100	100
Smart Meters	200	200	-	-	-
Ripple Reciever Replacement	200	200	-	-	-
Routine Expenditure	78	78	78	78	78
Total	3,475	3,766	2,307	863	178

7.2 Commentary

The buildings component of our non-network expenditure forecast includes the redevelopment of the Chelmer Street site (our administration and operations site) between FY24 and FY26. This project will increase the resilience of our operations and involves redevelopment of our yard and construction of a new earthquake rated (IL4) operations building and control room.

The vehicles and plant components include end of life replacement of network vehicles and plant. Information Technology includes routine replacement of server hardware, computers, and mobile devices, as well as investment in systems to replace ageing software, and to enhance the business operations. The management of the IT infrastructure and software future state has been integrated in a Digital Utility Roadmap as described in 7.2.1. It should be noted that costings for the Digital Utility Roadmap are indicative only as suitable solutions to fit our business are yet to be confirmed.

7.2.1 Digital Utility Roadmap

As a business we identified the future state capabilities that we need for the benefit of our customers, staff and stakeholders. This led to the development of a Digital Utility Roadmap that will drive a data-centric transition of capabilities for the benefit of customers, staff and stakeholders. Developing our data capability across the business will enable improved efficiency, capability and customer service reflected in improved network capability, reliability, safety, asset management and development decision making and improved visibility of customer service delivery. These systems are required to allow us to cost effectively deliver a network that meets our customer needs to the significant electricity energy demand required over the next decade and on. The future state business capability themes identified are presented in the diagram below:

Diagram 91 - Future state business capability themes

These have then been organised in four logical streams to allow us to develop into co-ordinated work streams as detailed in the diagram below.:

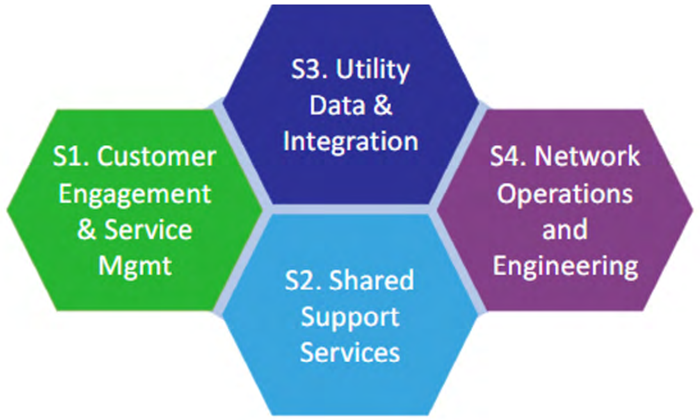


Diagram 93 - Future state business capability logical work streams

These stream initiatives have been prioritised by business importance and developed into the following planned digital system roadmap.

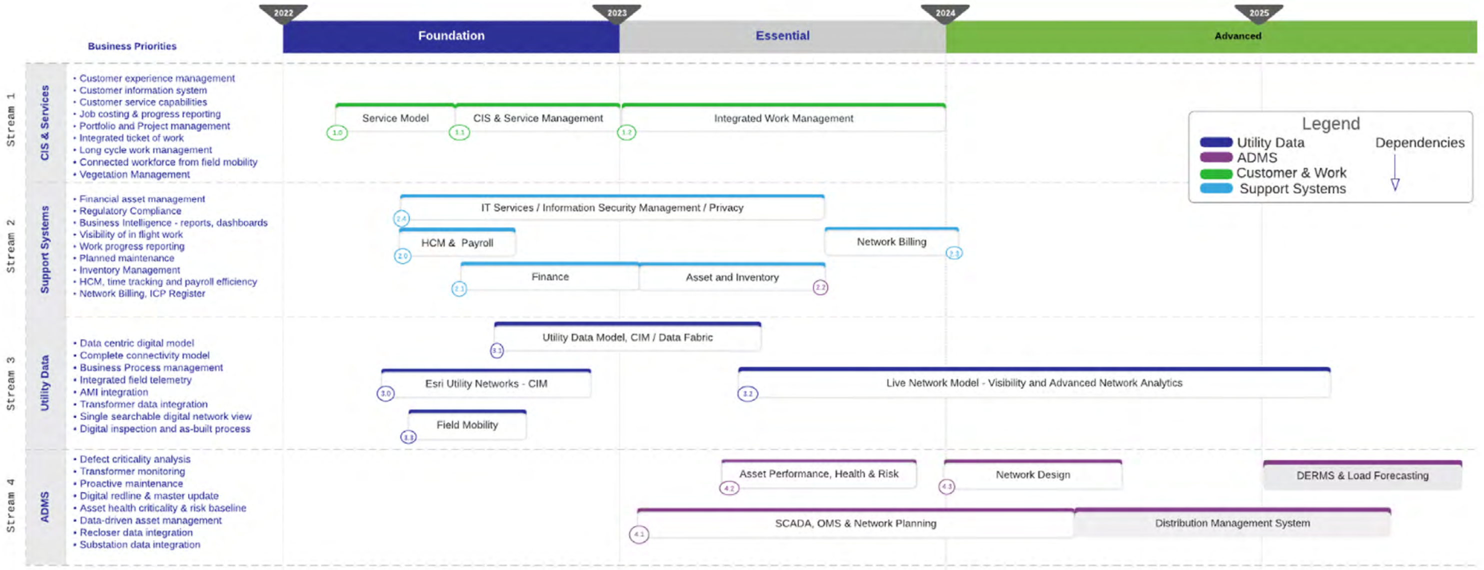


Diagram 94 - Planned digital system roadmap

We are progressing through the prioritised programme of works and developing business cases for ongoing investments and implementation. Each phase of work will undergo a separate detailed review of future state requirements, required capability, delivery options, and cost benefit analysis before implementation.

Summary of Expenditure Forecasts

08

08

Summary of Expenditure Forecasts

The summary of our forecast expenditure for the planning period is presented on the following pages

These forecasts are reasonably accurate for the first five years of the planning period, with the figures being indicative beyond that point. Many of our investment, maintenance and renewal decisions will be very dependent on the outcomes of inspections in the first five years, on customer growth, and other issues that are currently out of our control, such as the development of the Transpower transmission network.

Table 73 - Summary of expenditure forecasts

Network Capital Expenditure	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Consumer Connection	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509
System Growth	10,829	2,755	4,175	3,800	1,000	3,250	3,650	5,475	7,675	12,590
Asset Replacement & Renewal	5,085	8,818	6,366	6,227	6,146	6,131	5,842	5,911	5,698	5,996
Asset Relocations	-	221	-	-	-	-	-	-	-	-
Reliability, Safety & Environment - Quality of Supply	953	650	450	450	450	500	800	200	200	200
Reliability, Safety & Environment - Legislative & Regulatory	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-
Total Capital Expenditure	**18,376**	**13,953**	**12,500**	**11,986**	**9,105**	**11,390**	**11,801**	**13,095**	**15,082**	**20,295**
Network Operational Expenditure										
Service Interuptions & Emergencies	483	470	460	460	460	460	460	460	460	460
Vegetation Management	712	712	712	712	712	712	712	712	712	712
Routine & Corrective Maintenance and Inspections	1,298	1,379	1,323	1,326	1,312	1,340	1,326	1,326	1,326	1,312
Asset Replacement & Renewal	261	261	243	243	243	201	201	201	201	201
Total Operational Expenditure	**2,753**	**2,821**	**2,738**	**2,741**	**2,727**	**2,713**	**2,699**	**2,699**	**2,699**	**2,685**
Total Expenditure	**21,129**	**16,773**	**15,238**	**14,727**	**11,832**	**14,103**	**14,500**	**15,794**	**17,781**	**22,980**

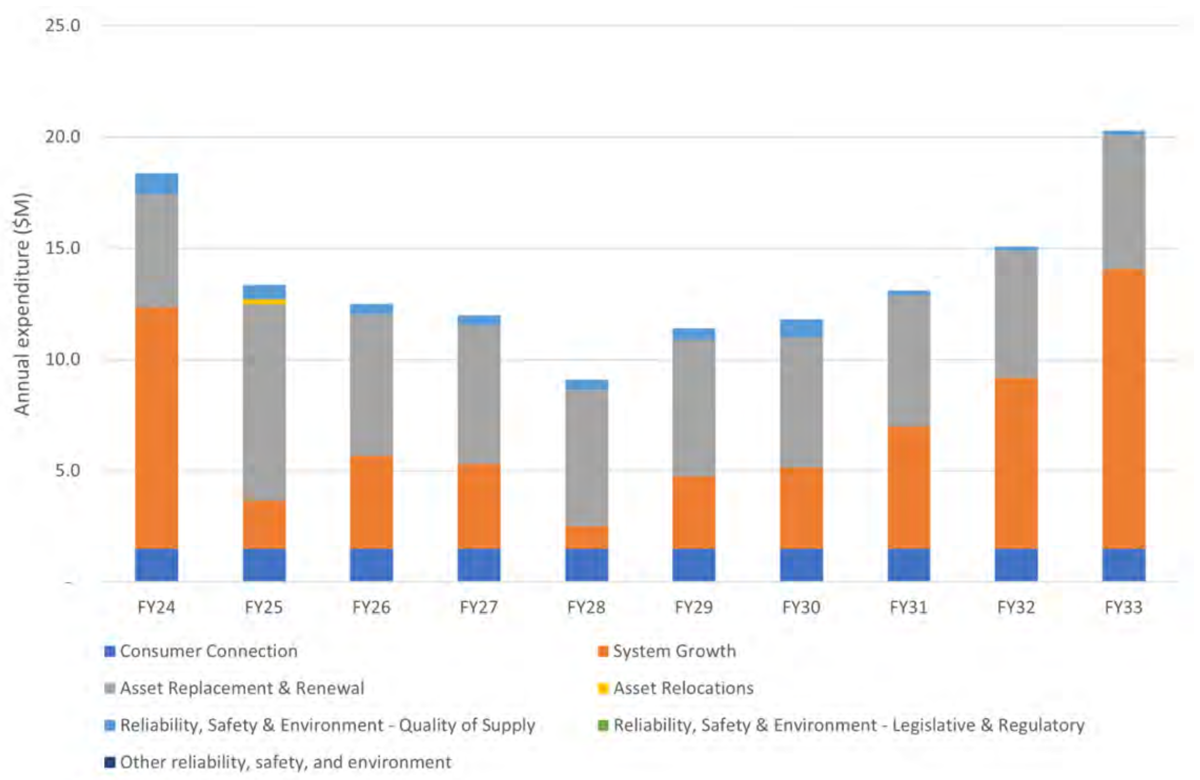


Figure 95 - Annual capital expenditure forecast by category

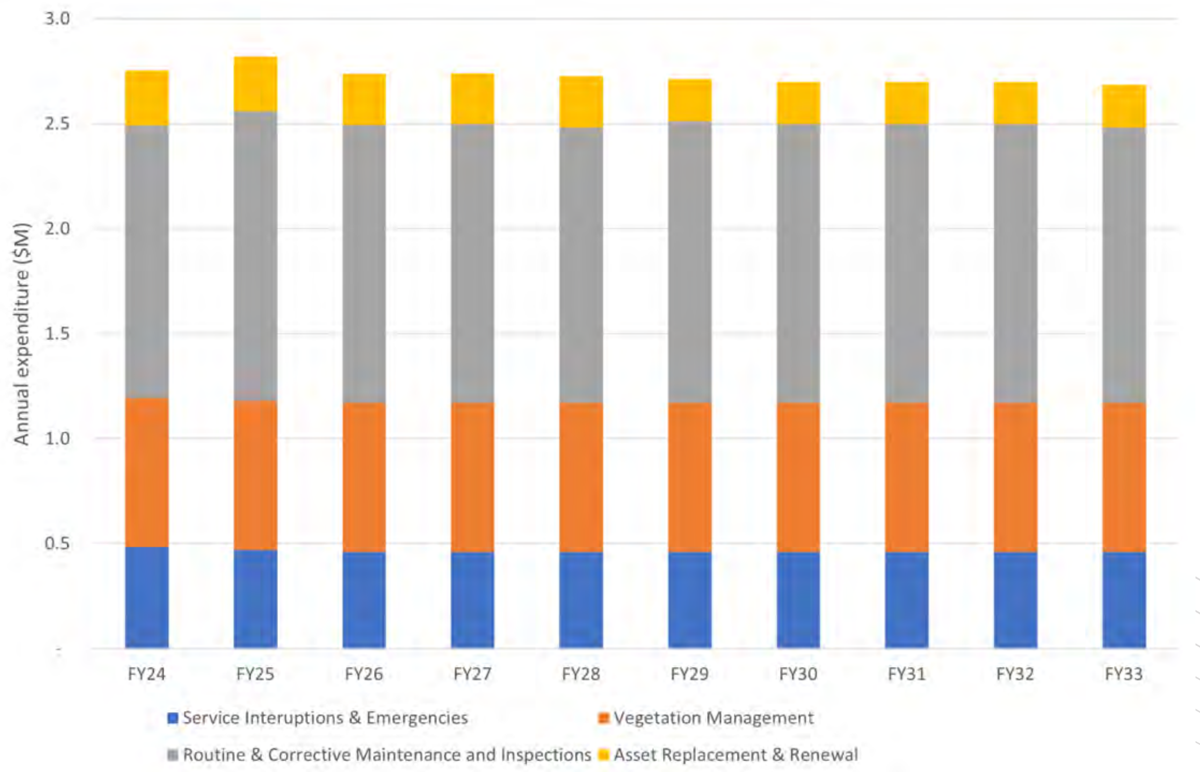


Figure 96 - Annual operational expenditure forecast by category

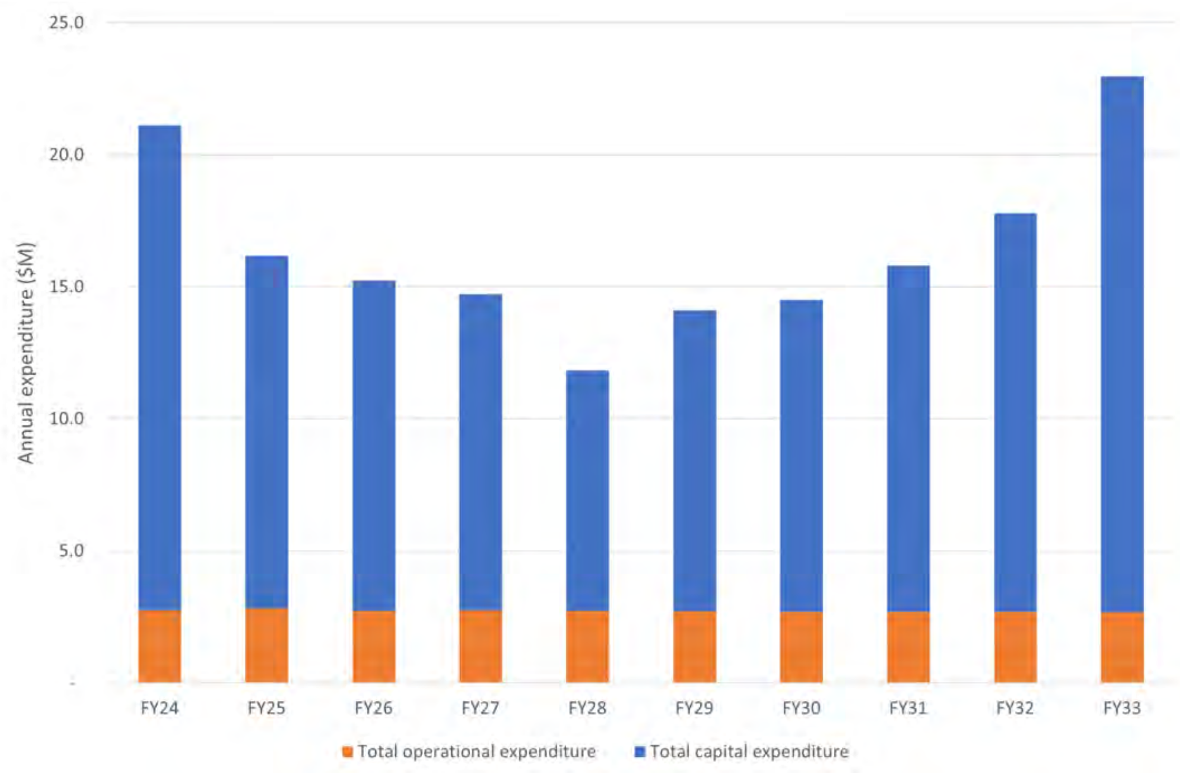


Figure 97 - Summary of total network expenditure forecast across planning period

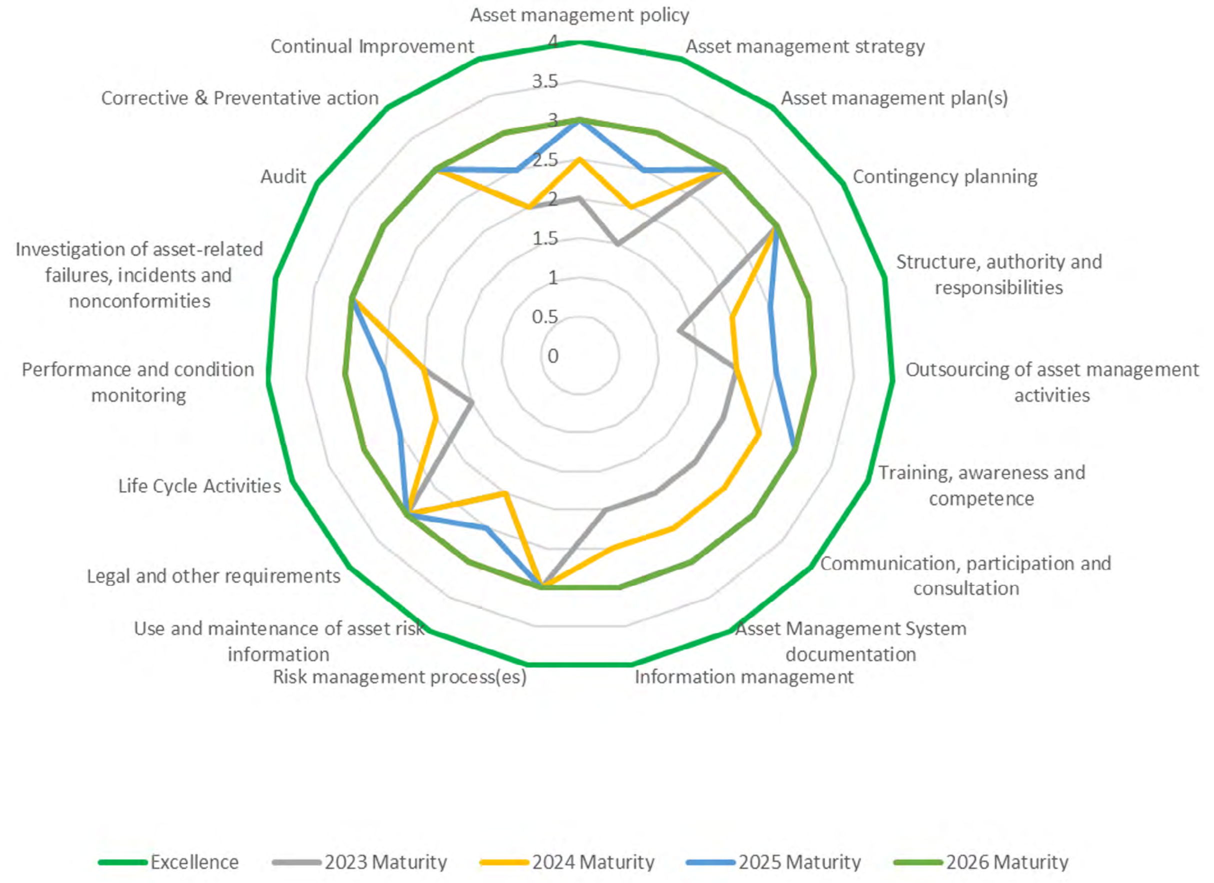
Appendices

Appendix A - Asset Management Maturity Development Plan

As described in section 4.6, Network Waitaki is developing its asset management practices to align with ISO55001 and has identified a range of improvements to enable this. The proposed improvements and their timing are summarised in the table below:

Improvement	Priority	Status	Target Year
Review the asset management policy to ensure that it represents Network Waitaki's current requirements	1	Complete	2022
Review roles, accountabilities, and key result areas to ensure alignment with the organisation's asset management policy and strategy	1	Underway	2022
Complete the asset information review	1	Underway	2022
Develop a strategic asset management improvement plan with initiatives framed and sequenced	1	Complete	2022
Develop a high-level asset management strategy defining Network Waitaki's approach to planning network investment	1	Underway	2023
Review roles and responsibilities for development, monitoring, management, and implementation of the asset management plan and work programme	1	Underway	2023
Document required asset management related competencies	1	Not Started	2023
Develop a formalised stakeholder communication plan	1	Underway	2023
Implement a portfolio management function	1	Complete	2023
Review asset maintenance standards and their implementation	1	Underway	2023
Review asset inspection standards and data management systems to enable the recording of asset condition for use in future modelling	1	Underway	2023
Include condition or health indicator profiles as part of asset renewal justifications in the AMP	1	Complete	2023
Ensure that the contents of the policy are communicated to relevant stakeholders and that its contents are implemented	2	Underway	2023
Develop a resourcing strategy and plan to proactively identify the organisation's current and projected future requirements	2	Not Started	2023
Develop a more comprehensive asset information strategy that links asset information systems to corporate and asset management objectives	2	Not Started	2023
Develop asset fleet plans for core asset classes defining Network Waitaki's lifecycle management strategies for each fleet from procurement to disposal	2	Underway	2024
Assign accountability and develop a system for planning the overall portfolio of work including performance measures and resource forecasting	2	Not Started	2024
Identify system elements for which improvement will provide cost effective benefits and include in an asset management improvement plan	2	Underway	2024
Review the current design standard and develop a forward work plan to progressively improve the level of specification that it includes	2	Not Started	2024
Review the approach to procurement of major plant items, ideally aligning with design standard choices and fleet asset strategies	2	Not Started	2024
Implement a computerised maintenance management system for planning and scheduling maintenance and recording and reporting history	2	Not Started	2024
Develop an overall asset information roadmap that can be used for planning for resourcing and implementation	3	Not Started	2024
Develop methods for assessing value for money for work completed internally	3	Not Started	2025
Review specialist activities that are currently outsourced to identify if internal capabilities are sufficient to effectively specify and control these activities	3	Not Started	2025

These improvements will ensure compliance with the standard at minimum by 2026 and expected progress is illustrated below.



Appendix B -

Compliance Schedule to Electricity Distribution Information Disclosure Amendment Determination 2022

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
3 The AMP must include the following -	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Executive Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes	Section 4 Section 6.1-6.3
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	4.1.4
3.3.2 states the corporate mission or vision as it relates to asset management	4.1.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.1.4 Section 4 Section 6
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	4.1
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.1 4.1
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	1
3.5 The date that it was approved by the directors	1.8
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	
3.6.1 how the interests of stakeholders are identified	2.5
3.6.2 what these interests are	2.5
3.6.3 how these interests are accommodated in asset management practices; and	2.5
3.6.4 how conflicting interests are managed	2.5
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors	2.1.3
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured and	2.1.4
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.1.4
3.8 All significant assumptions	Assumptions are detailed in each section that they apply
3.8.1 quantified where possible	
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Information Disclosures in appendices
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Information Disclosures in appendices
3.10 An overview of asset management strategy and delivery	4.1
3.11 An overview of systems and information management data	Throughout document
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	4.6.2
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	4.2.3, 5.3
3.13.2 planning and implementing network development projects	4.2.7, 6.3
3.13.3 measuring network performance.	Section 3
3.14 An overview of asset management documentation, controls and review processes	4.6
3.15 An overview of communication and participation processes	2.5
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	Throughout AMP
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout AMP
Assets covered	
4 The AMP must provide details of the assets covered, including-	
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	
4.1.1 the region(s) covered	1.1.1, 2.7
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	2.5.1
4.1.3 description of the load characteristics for different parts of the network	Throughout section 6
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.6.2
4.2 a description of the network configuration, including-	
4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	2.6
4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	5.6, 5.7
4.2.3 a description of the distribution system, including the extent to which it is underground;	5.8
4.2.4 a brief description of the network's distribution substation arrangements;	5.8
4.2.5 a description of the low voltage network including the extent to which it is underground; and	5.8

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	5
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 must be disclosed for each sub-network.	N/A
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1 voltage levels;	5
4.4.2 description and quantity of assets;	5
4.4.3 age profiles; and	5
4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	5
4.5 The asset categories discussed in subclause 4.4 should include at least the following-	
4.5.1 The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii)	5, 6
4.5.2 Assets owned by the EDB but installed at bulk electricity supply points owned by others	5, 6
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	5, 6
4.5.4 Other generation owned by the EDB.	N/A
Service levels	
5 The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	3
5.1 EDBs are to describe how they provide notice and communicate planned and unplanned interruptions, including any plans for changes or improvements in this area	3.4.2
5.2 Describe the practices for connecting consumers and making alterations to existing connections, including:	3.4.1
5.2.1 Planning and management regarding connecting new consumers or making alterations to existing connections (offtake and injection connections);	3.4.1
5.2.2 How we seek to minimise the cost to consumers of new or altered connections;	3.4.1
5.2.3 Our approach to planning and managing communication with consumers about new or altered connections;	3.4.1
5.2.4 Commonly encountered delays, issues, and potential timeframes for different connection types.	3.4.1
5.2.5 Describe customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	3.3
5.2.6 Our approach to planning and managing customer complaint resolution.	3.3.1
6 Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Information disclosures in appendix
7 Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types;	3, 6.2, 6.3

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.4
7.3 EDBs to describe their practices for monitoring voltage quality (including any plans for improvements) including:	3.4.3
7.3.1 what the EDB is doing to develop and improve practices for monitoring voltage quality on its low voltage (LV) network;	3.4.3
7.3.2 work it is doing on their LV network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	6.4.1
7.3.3 how it is responding to and reporting on voltage quality issues when it identifies them, or they are raised by a stakeholder;	3.4.3
7.3.4 how it is communicating the work it is doing to improve voltage quality on its LV network to affected consumers.	3.4.3
8 The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	3
9 Targets should be compared to historic values where available to provide context and scale to the reader.	3
10 Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	5, 6
Network Development Planning	
11 AMPs must provide a detailed description of network development plans, including—	
11.1 A description of the planning criteria and assumptions for network development;	6.3
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Throughout section 6
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	Throughout section 4, throughout section 6
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
11.4.1 the categories of assets and designs that are standardised;	Throughout sections 4, 5, 6
11.4.2 the approach used to identify standard designs.	Throughout sections 4, 5, 6
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	6.3.2.2
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	6.3
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	6.3
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	6.4
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	6.4

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	6.4
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Section 6
11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.	6.3
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	Section 6
11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	Section 6
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	Throughout AMP
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	
11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	Section 6
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	Throughout AMP
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.	Throughout AMP
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	6.2.6
11.12 A description of the EDB's policies on non-network solutions, including-	
11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	6.2.6
11.12.2 the potential for non-network solutions to address network problems or constraints.	
11.13 Describe how we assess the impact that new connections will have on our network, including:	
11.13.1 how we measure the scale and impact of new connections;	
11.13.2 how we take the timing and uncertainty of new connections into account;	Throughout section 6
11.13.3 how we take other factors into account, eg the network location of new connections;	
11.13.4 how we assess and manage the risk posed by uncertainty regarding new connections.	
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12 The AMP must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	5.3
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	5

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	5
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	5
12.3.2 a description of innovations that have deferred asset replacements;	5
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5
12.3.4 a summary of the projects planned for the following four years (where known); and	5
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	5
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	5
Non-Network Development, Maintenance and Renewal	
13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1 a description of non-network assets;	7
13.2 development, maintenance and renewal policies that cover them;	7
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	7
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	7
Risk Management	
14 AMPs must provide details of risk policies, assessment, and mitigation, including—	4.3
14.1 Methods, details and conclusions of risk analysis;	4.3
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	4.5
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	4.5
14.4 Details of emergency response and contingency plans.	4.5
Evaluation of performance	
15 AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	3
15.2 An evaluation and comparison of actual service level performance against targeted performance;	3
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	4.6
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	4.6

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
Capability to deliver	
16 AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved;	4.2, 4.1.3.4
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1.4
Innovation Practices	
17.1 Describe any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was published, including case studies and trials;	Throughout Section 6
17.2 Describe what the desired outcome of any innovation practices is, and how it may improve outcomes for consumers;	
17.3 Describe how we measure success and make decisions regarding any innovation practices, eg, how we decide whether to commence, commercially adopt, or discontinue any innovation practices;	
17.4 How our decision-making about innovation practices may depend on the work of other companies, including other EDBs and providers of non-network solutions;	
17.5 The types of information we use to inform or enable innovation practices, and their approach to seeking that information.	

Appendix C – EDB Information Disclosure Requirements Schedules

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 11a–13

Company Name	Network Waitaki Ltd
Disclosure Date	31 March 2023
AMP Planning Period Start Date (first day)	1 April 2023

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 5.1. Prepared 24 November 2022

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

11a(i): Expenditure on Assets Forecast

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
	$000 (in nominal dollars)										
Consumer connection	1,743	1,509	1,584	1,632	1,665	1,698	1,732	1,766	1,802	1,838	1,875
System growth	1,093	10,829	2,263	4,515	4,192	1,125	3,730	4,273	6,537	9,348	15,641
Asset replacement and renewal	4,564	5,085	9,259	6,885	6,869	6,916	7,037	6,839	7,058	6,940	7,449
Asset relocations	6	-	232	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	1,342	953	683	487	496	506	574	937	239	244	248
Legislative and regulatory	250										
Other reliability, safety and environment	-										
Total reliability, safety and environment	1,592	953	683	487	496	506	574	937	239	244	248
Expenditure on network assets	8,998	18,376	14,020	13,519	13,222	10,246	13,072	13,815	15,636	18,369	25,212
Expenditure on non-network assets	482	3,475	3,766	2,355	899	189	262	378	329	278	284
Expenditure on assets	9,480	21,851	17,786	15,874	14,121	10,435	13,334	14,193	15,965	18,647	25,496
plus Cost of financing											
less Value of capital contributions	1,952	2,080	1,730	1,716	2,054	2,066	2,135	2,147	1,777	1,789	1,802
plus Value of vested assets											
Capital expenditure forecast	7,529	19,771	16,056	14,158	12,067	8,369	11,199	12,045	14,188	16,858	23,694
Assets commissioned	6,494	20,631	16,231	14,158	12,067	8,169	8,749	14,495	9,813	21,433	23,694

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
	$000 (in constant prices)										
Consumer connection	1,743	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509	1,509
System growth	1,094	10,829	2,755	4,175	3,800	1,000	3,250	3,650	5,475	7,675	12,590
Asset replacement and renewal	4,564	5,085	8,818	6,366	6,227	6,147	6,131	5,842	5,911	5,698	5,996
Asset relocations	6	-	221	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	1,342	953	650	450	450	450	500	800	200	200	200
Legislative and regulatory	250	-	-	-	-	-					
Other reliability, safety and environment	-	-	-	-	-	-					
Total reliability, safety and environment	1,592	953	650	450	450	450	500	800	200	200	200
Expenditure on network assets	8,999	18,376	13,953	12,500	11,986	9,106	11,390	11,801	13,095	15,082	20,295
Expenditure on non-network assets	482	3,475	3,766	2,307	863	178	242	342	292	242	242
Expenditure on assets	9,481	21,851	17,719	14,807	12,849	9,284	11,632	12,143	13,387	15,324	20,537

Subcomponents of expenditure on assets (where known)
**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											
Cybersecurity (Commission only)											

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	-	75	123	156	189	223	258	293	329	366
System growth	(1)	-	(492)	340	392	125	480	623	1,062	1,673	3,051
Asset replacement and renewal	-	-	441	519	642	770	906	997	1,147	1,242	1,453
Asset relocations	-	-	11	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	33	37	46	56	74	137	39	44	48
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	-	33	37	46	56	74	137	39	44	48
Expenditure on network assets	(1)	-	68	1,019	1,236	1,140	1,682	2,014	2,541	3,287	4,918
Expenditure on non-network assets	-	-	-	48	36	11	20	36	37	36	42
Expenditure on assets	(1)	-	68	1,067	1,272	1,151	1,702	2,050	2,578	3,323	4,959

Commentary on options and considerations made in the assessment of forecast expenditure
EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Consumer types defined by EDB**	**$000 (in constant prices)**					
Install Distribution Transformers – Customer	259	438	438	438	438	438
New 11kV Network Extensions	660	514	514	514	514	514
New LV Service Extensions	783	356	356	356	356	356
Residential Subdivisions	41	201	201	201	201	201
**include additional rows if needed*						
Consumer connection expenditure	1,743	1,509	1,509	1,509	1,509	1,509
less Capital contributions funding consumer connection	1,307	1,132	1,132	1,132	1,132	1,132
Consumer connection less capital contributions	436	377	377	377	377	377

11a(iii): System Growth

Subtransmission	565	6,304	200	3,675	-	200
Zone substations	476	3,810	800	-	3,000	-
Distribution and LV lines	53	275	1,275	500	800	800
Distribution and LV cables		440	400	-	-	-
Distribution substations and transformers		-	-	-	-	-
Distribution switchgear		-	80	-	-	-
Other network assets		-	-	-	-	-
System growth expenditure	1,094	10,829	2,755	4,175	3,800	1,000
less Capital contributions funding system growth	645	948	598	584	922	934
System growth less capital contributions	449	9,881	2,157	3,591	2,878	66

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(iv): Asset Replacement and Renewal	**$000 (in constant prices)**					
Subtransmission	102	217	1,050	504	504	524
Zone substations	39	635	1,836	1,080	815	661
Distribution and LV lines	3,357	2,096	2,827	2,958	3,016	3,002
Distribution and LV cables	90	428	142	146	164	182
Distribution substations and transformers	393	314	364	414	464	514
Distribution switchgear	583	1,064	1,444	1,264	1,264	1,264
Other network assets	-	331	1,155			
Asset replacement and renewal expenditure	4,564	5,085	8,818	6,366	6,227	6,147
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	4,564	5,085	8,818	6,366	6,227	6,147

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(v): Asset Relocations						
*Project or programme**	**$000 (in constant prices)**					
Transpower Clearances Aviemore	6	-	-	-	-	-
Subtransmission			36			
Distribution and LV lines			185			
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	6	-	221	-	-	-
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	6	-	221	-	-	-

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(vi): Quality of Supply						
*Project or programme**	**$000 (in constant prices)**					
Subtransmission	118					
Zone substations	35					
Distribution	82					
Distribution - switchgear	390					
Other	717	953	650	450	450	450
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	1,342	953	650	450	450	450
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,342	953	650	450	450	450

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(vii): Legislative and Regulatory						
*Project or programme**	**$000 (in constant prices)**					
Zone substations	6					
Distribution	244					
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	250	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	250	-	-	-	-	-

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(viii): Other Reliability, Safety and Environment						
*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]						
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
11a(ix): Non-Network Assets						
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
Vehicles	53	60	-	58	-	-
Smart Meters		200	200			
Ripple Receiver Replacement		200	200			
Communication Upgrades		100	100			
Information Technology	150	100	100	100	100	100
**include additional rows if needed*						
All other projects or programmes - routine expenditure	46	78	78	78	78	78
Routine expenditure	249	738	678	236	178	178
Atypical expenditure						
*Project or programme**						
Depot Redevelopment (Buildings)	233	2,737	3,088	2,071	685	
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	233	2,737	3,088	2,071	685	-
Expenditure on non-network assets	482	3,475	3,766	2,307	863	178

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

ch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	693	483	493	498	508	518	528	539	550	561	572
11	Vegetation management	656	712	747	770	785	801	817	833	850	867	884
12	Routine and corrective maintenance and inspection	1,071	1,345	1,398	1,430	1,463	1,476	1,538	1,552	1,583	1,615	1,630
13	Asset replacement and renewal	597	261	274	263	268	273	231	235	240	245	250
14	**Network Opex**	3,017	2,800	2,912	2,961	3,024	3,068	3,114	3,159	3,223	3,287	3,335
15	System operations and network support	3,374	4,896	4,686	4,843	4,993	5,095	5,199	5,305	5,413	5,524	5,637
16	Business support	4,426	4,660	4,823	4,979	5,225	5,345	5,443	5,546	5,652	5,762	5,875
17	**Non-network opex**	7,800	9,557	9,508	9,823	10,218	10,440	10,642	10,851	11,065	11,286	11,512
18	**Operational expenditure**	10,817	12,357	12,420	12,784	13,241	13,508	13,756	14,010	14,288	14,573	14,847

ch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
21		$000 (in constant prices)										
22	Service interruptions and emergencies	693	483	470	460	460	460	460	460	460	460	460
23	Vegetation management	656	712	712	712	712	712	712	712	712	712	712
24	Routine and corrective maintenance and inspection	1,071	1,345	1,331	1,323	1,326	1,312	1,340	1,326	1,326	1,326	1,312
25	Asset replacement and renewal	597	261	261	243	243	243	201	201	201	201	201
26	**Network Opex**	3,017	2,800	2,773	2,738	2,741	2,727	2,713	2,699	2,699	2,699	2,685
27	System operations and network support	3,374	4,896	4,556	4,556	4,558	4,560	4,562	4,564	4,566	4,568	4,570
28	Business support	4,426	4,660	4,516	4,545	4,594	4,608	4,600	4,595	4,591	4,589	4,587
29	**Non-network opex**	7,800	9,557	9,072	9,101	9,152	9,168	9,162	9,159	9,157	9,157	9,157
30	**Operational expenditure**	10,817	12,357	11,845	11,839	11,893	11,895	11,875	11,858	11,856	11,856	11,842

31 **Subcomponents of operational expenditure (where known)**

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

ch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	585	646	684	684	684	684	684	684	684	684	684
37	Cybersecurity (Commission only)		293	312	312	312	312	312	312	312	312	312

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

ch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
42	**Difference between nominal and real forecasts**	$000										
43	Service interruptions and emergencies	-	-	23	38	47	58	68	79	89	100	112
44	Vegetation management	-	-	36	58	73	89	105	121	138	155	172
45	Routine and corrective maintenance and inspection	-	-	67	108	137	164	198	226	257	289	318
46	Asset replacement and renewal	-	-	13	20	25	30	30	34	39	44	49
47	**Network Opex**	-	-	139	223	283	341	401	461	524	588	651
48	System operations and network support	-	-	130	287	435	535	637	741	847	956	1,067
49	Business support	-	-	307	435	631	737	843	951	1,061	1,173	1,288
50	**Non-network opex**	-	-	437	722	1,066	1,272	1,480	1,692	1,908	2,129	2,355
51	**Operational expenditure**	-	-	575	945	1,348	1,614	1,880	2,152	2,432	2,717	3,005

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

54 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)							
8–9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.01%	40.91%	33.47%	9.06%	16.55%		3	8.10%
11	All	Overhead Line	Wood poles	No.	0.09%	46.51%	17.21%	20.48%	15.71%		3	8.10%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	13.80%	35.51%	50.69%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			1.40%	89.77%	8.83%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		-	-				N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		10.53%	21.05%	15.79%	52.63%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				100.00%			4	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		2.13%	12.77%	74.47%	10.63%		4	2.13%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	12.77%	36.17%	51.06%			3	17.02%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.			100.00%				4	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	2.36%	9.45%	6.30%	49.61%	32.28%		4	11.81%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.			25.00%	50.00%	25.00%		4	

	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	21.74%	21.74%	21.74%	34.78%		4	13.04%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	8.99%	44.20%	26.83%	19.98%		3	7.72%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km		4.46%	0.30%	58.51%	36.73%		3	-
44	HV	Distribution Cable	Distribution UG PILC	km	1.92%	20.57%	39.29%	37.68%	0.54%		3	2.48%
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	2.50%		32.50%	47.50%	17.50%		4	2.50%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.89%	10.46%	16.91%	59.76%	10.98%		3	11.32%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.		7.28%	28.13%	48.96%	15.63%		4	14.06%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.17%	4.74%	35.39%	41.54%	18.16%		3	6.23%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.18%	1.41%	13.71%	60.29%	24.41%		4	1.72%
53	HV	Distribution Transformer	Voltage regulators	No.			5.56%	69.44%	25.00%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.		30.00%	70.00%				3	-
55	LV	LV Line	LV OH Conductor	km	0.49%	24.28%	70.65%	2.74%	1.84%		3	4.00%
56	LV	LV Cable	LV UG Cable	km	-	-	18.84%	47.11%	34.05%		3	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km		5.00%	95.00%				3	5.00%
58	LV	Connections	OH/UG consumer service connections	No.		5.46%	19.94%	36.63%	37.97%		2	2.23%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		3.00%	77.00%	10.00%	10.00%		3	3.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot		50.00%	25.00%	15.00%	10.00%		4	50.00%
61	All	Capacitor Banks	Capacitors including controls	No.				100.00%			4	
62	All	Load Control	Centralised plant	Lot			100.00%				4	
63	All	Load Control	Relays	No.		20.00%		80.00%			4	
64	All	Civils	Cable Tunnels	km							N/A	

Company Name **Network Waitaki Ltd**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*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
8										
9	Ruataniwha	1	2	N	1	42%	2	46%	No constraint within +5 years	
10	Ohau	1	3	N	2	47%	3	53%	No constraint within +5 years	
11	Omarama	2	6	N	4	28%	3	60%	No constraint within +5 years	
12	Otematata	1	3	N	2	20%	3	20%	No constraint within +5 years	
13	Kurow	5	10	N-1	5	53%	10	47%	No constraint within +5 years	
14	Otekaieke	-	-	-	-	-	7	61%	No constraint within +5 years	
15	Duntroon	6	7	N	1	81%	7	57%	No constraint within +5 years	
16	Ngapara	6	7	N	2	79%	7	64%	No constraint within +5 years	
17	Awamoko	-	-	-	-	-	7	66%	No constraint within +5 years	
18	Papakaio	6	7	N	1	86%	7	93%	No constraint within +5 years	
19	Enfield	2	7	N	5	33%	7	36%	No constraint within +5 years	
20	Parsons Road	4	10	N	6	38%	10	41%	No constraint within +5 years	
21	Pukeuri	9	12	N-1	3	78%	12	96%	No constraint within +5 years	
22	Chelmer Street	10	28	N-1	19	34%	28	38%	No constraint within +5 years	
23	Redcastle	9	15	N-1	6	62%	15	74%	No constraint within +5 years	
24	Five Forks	1	7	N	6	20%	7	27%	No constraint within +5 years	
25	Maheno	4	5	N	2	70%	5	82%	No constraint within +5 years	
26	Hampden	1	7	N	6	20%	7	34%	No constraint within +5 years	
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Network Waitaki Ltd**
AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11	*Consumer types defined by EDB**						
12	Small: residential and commercial to 15kVA	11,544	11,280	11,382	11,484	11,588	11,692
13	Medium: residential and commercial 16kVA to 50kVA	1,186	1,479	1,493	1,506	1,520	1,533
14	Large: commercial and industrial 51kVA and above	589	595	600	605	611	616
15	Independent Contract Consumers ("IND")	86	87	88	89	90	91
16	[EDB consumer type]						
17	**Connections total**	13,405	13,442	13,563	13,685	13,808	13,932
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	185	193	204	221	243	267
24	Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
25	**12c(ii) System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
28	GXP demand	75	78	83	85	86	93
29	*plus* Distributed generation output at HV and above						
30	**Maximum coincident system demand**	75	78	83	85	86	93
31	*less* Net transfers to (from) other EDBs at HV and above						
32	**Demand on system for supply to consumers' connection points**	75	78	83	85	86	93
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	291	342	358	362	392	423
35	*less* Electricity exports to GXPs						
36	*plus* Electricity supplied from distributed generation						
37	*less* Net electricity supplied to (from) other EDBs						
38	**Electricity entering system for supply to ICPs**	291	342	358	362	392	423
39	*less* Total energy delivered to ICPs	274	322	336	340	369	398
40	**Losses**	17	20	22	22	23	25
41							
42	**Load factor**	44%	50%	49%	49%	52%	52%
43	**Loss ratio**	5.8%	5.8%	6.1%	6.1%	5.9%	5.9%
44							

Company Name: **Network Waitaki Ltd**
AMP Planning Period: **1 April 2023 – 31 March 2033**
Network / Sub-network Name: **Network Waitaki Ltd**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	105.0	105.0	105.0	105.0	105.0	105.0
12	Class C (unplanned interruptions on the network)	45.0	55.0	55.0	55.0	55.0	55.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.40	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	0.80	1.30	1.30	1.30	1.30	1.30

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	An asset management policy exists which is approved by the Board of Directors. The document has limited circulation and its content is not widely known.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). 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.
10	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?	2	Asset management strategies thinking and content is being detailed in the AMP and links showing alignment across business policies and strategies are now being demonstrated.	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 (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, 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.
11	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	Lifecycle strategies and asset fleet strategies are being developed on a highest risk basis. End to end business processes are being considered and being introduced in the business.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, 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.
26	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 portfolios show the medium-term work program for most asset classes but these are not widely published. This makes it difficult to monitor the delivery of the asset management plan and compare this against baseline targets. This may compromise Network Waitaki's ability to deliver to plan generally and particularly for larger and more complex initiatives such as zone substations	The asset management strategy need 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 optimize 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).

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2023 – 31 March 2033
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	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?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	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?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
27	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?	2	A document or system providing clear forward visibility of work in 1 year 5 year and longer time horizons that include targets such as 'on-time, on-budget' measures is not readily visible or used as a management tool. it is therefore not possible to communicate a corresponding medium to long term work delivery or implementation plan. The current approach for forecasting longer term requirements appears to be based on historical requirements with minor adjustments year on year with inclusions for known major projects. Detailed work is planned only for a relatively short time horizon of 3 months for routine work and longer times for larger projects.	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) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2	The Asset Management Plan provides some reference to asset management governance in Section 2.1.5 but this is not well aligned with accountabilities described in position descriptions. Position descriptions while providing a broad description of responsibilities do not appear to be aligned with an organization design structured specifically to execute the asset management strategy. Additionally, position description accountability and KRA's are in many cases not well aligned with KRA's in some cases being superficial and not focused on clear outcomes aligned with objectives and strategy.	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.
31	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)	2	As the asset management fleet strategies continue to be developed, this is enabling high level resource forecasting. Recent appointment of the People and Culture Manager has increased focus on ensuring current resourcing will be available to meet future requirements.	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. 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.
33	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?	3	Network Waitaki has contingency plans in place for foreseeable HILP events as well as credible equipment scenarios such as loss of major plant. These plans were reviewed externally in 2019/2020 with improvements arising from this review implemented. Network Waitaki is a lifelines utility and a member of the lifelines group and as such has linkages with other parties associated with the Emergency Management Agency (EMA) such as fire service, police. Network Waitaki also has agreements in place with neighboring networks to provide mutual aid. While detailed contingency plans are in place for most major plant items, development of detailed pre-prepared plans remains a work in progress. Network Waitaki currently does not use the Coordinated Incident Management System (CIMS) framework. There may be benefits in implementing this to enhance coordination with other EMA parties in the event of a major HILP event.	Widely used AM 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) 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
37	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)?	2	The company has undertaken recent restructuring and appointments to ensure appropriate focus on critical asset management functions. Further refinements are programmed to facilitate the ongoing needs of the company.	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 eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 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.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Changes to the asset fleets strategies have allowed alignment of forecast network requirements to be aligned with other 10 year business modelling being utilised to drive business strategies.	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.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	The importance of meeting asset management requirements appears to be well communicated by top management. There is an annual performance review process which can be used to reinforce the importance of meeting objectives and align these with employee interests through incentives. Company performance and objectives are included in standing agendas for management meetings and whole of company briefings.	Widely used AM 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 (eg, 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.
45	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	Contractors for routine work are selected based on a somewhat informal and subjective assessment of capability, reputation, and past performance. While perhaps less formal, the current approach appears to be effective in ensuring required resource availability, timeliness, and quality of work. Specialist contractors and consultants are selected based on capability and reputation. For specialist work Network Waitaki takes an outcome-based approach specifying end results and relying on contractors' expertise to define work scope and methods.	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 AM standards (eg, 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 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	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?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
48	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	The organisation has identified resource requirements at a high level for the routine work in the AMP. This is not fully developed as it does not identify skillset/training requirements for all aspects of the AMP. Records of competency, training and development are documented and available	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 considers e.g. 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.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Required competencies are recorded in relevant position descriptions, although review suggests that these are not detailed at sufficient detail to develop training plans. Training requirements not structured and are negotiated between managers and employees with a trigger being the annual performance review. There is no central system to manage competency requirements, identify gaps and manage training needs.	Widely used AM 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. (eg, 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.
50	Training, awareness and competence	How does the organization 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	Position descriptions for all roles exist however competence requirements are not specific relying instead upon broad descriptions of experience (sometimes expressed in number of years). This approach may not be effective in an environment with increased staff mobility between company's or different industry sectors, or in a business and technical environment undergoing substantial change. A documented framework for asset management competencies is not currently in place.	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization 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?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
53	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?	2	The AMP represents a significant stakeholder communication tool providing detailed information to any interested stakeholder. There are also a number of informal communication channels in place with stakeholders such as local government, major customers and industry groups (e.g. irrigation). There is currently no formal communication plan identifying stakeholders, their interests, communication channels, frequencies and accountable staff.	Widely used AM 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's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); 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.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Network Waitaki has documented an overall approach to asset management in the AMP (Chapter 4) describing the broad elements of an asset management system and referring to other Network Waitaki policies and standards where these are available. While indicating awareness of the need for an overarching system, the Chapter reads more as a statement of intent rather than a clear description of a system of interrelated policy, processes, standards, and control mechanisms. It is acknowledged that for an organization the size and scale of Network Waitaki it may not be cost efficient to implement a comprehensive asset management system. Rather Network Waitaki should identify the elements of an asset management system that provide the greatest benefit in assuring delivery of the corporate objectives and managing risks.	Widely used AM 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. (eg, 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.
62	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?	2	An asset information strategy or other documentation describing data requirements, quality standards and improvement plans does not exist. A project is however in place with a specialist consultant (Red Vespa) to establish Network Waitaki's requirements, gaps, and an overall improvement plan.	Effective asset management requires appropriate information to be available. Widely used AM 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.
63	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?	2	Scheduled inspections and pre-work site preparation provide confirmation that asset data is accurate. Field software is being adopted to maximise efficiency and reduce errors from the field. Personell in the office are responsible for recording information from teh field, with some already being electronically reported. Data audits are regularly carried out, and discrepancies corrected.	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 AM practice requirements (eg, 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	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?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	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?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	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?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The asset management information systems is sized to foreseeable needs and aligned with good industry practice. Work continues with users to identify their ongoing needs, as developments continue. Systems are review and updated as required to meet asset management goals.	Widely used AM 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 organisations needs, can be effectively used and can supply information which 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.
69	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	A risk framework is in place and has been authorized and implemented. Risks are being identified using a range of tools chosen to meet the task and required level of assessment. An audited public safety management system is in place. A process mapping tool Promap is used for documenting and managing critical processes and formally managing corrective actions arising from these processes.	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 (eg, para 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.
79	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?	3	Bowties are used for formally analyzing critical risks, a system 'Vault' is used for recording incidents near misses and associated corrective actions. A training framework is under development which will have linkages to risk assessments and where appropriate the outcome of incident investigations.	Widely used AM standards require that the output from risk assessments are 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 organisations 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.
82	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 is requirements incorporated into the asset management system?	3	A formal legal compliance management system (ComplyWith) has been implemented and is being actively used. This system includes a registry of requirements and declarations of compliance. Risk registers are in place that can be used to record risks associated with compliance.	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 (eg, 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 AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations 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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	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?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	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 is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
88	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?	2	A design standard exists for routine network assets such as overhead lines and distribution substations. This is however more a suite of design principles than a robust technical specification structured to achieve consistency in design, procurement, and construction. Larger 'non-routine' projects such as zone substations are not constructed to a formal standard, rather, these use previous examples as a template. The organization tends to select major equipment such as switchgear using a sole supplier approach, sometimes as a pragmatic response to short lead times between project initiation and requirement date. While sole sourcing is seen to provide benefits in terms of standardization and reducing design and implementation effort, it may not be the most efficient economically, or most advantageous technically. Project management and commissioning is usually supervised by the same engineer that designed the project. This can help to manage issues through the project and ensure the result is as envisaged in the absence of less formal processes.	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 (eg, 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) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	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?	1	Inspections and maintenance requirements are not formally scheduled using a robust system. Rather these are managed by spreadsheets that rely upon the diligence of the planner. There is limited reporting of compliance (e.g. overdue maintenance). Additionally, inspection records are held in an unstructured filing system making it a manual process to identify when assets were inspected, maintained and the as found/as left condition. Some inspection and maintenance standards exist, but quality and completeness vary and there are also gaps, particularly with respect to major plant items such as switchgear which rely upon manufacturer manuals or contractor procedures.	Having documented process(es) which 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 (eg, 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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	Systems are in place for measuring the performance of Network Waitaki's assets as required by Commerce Commission information disclosures. These include network performance metrics SAIDI, SAIFI and asset condition measures using health indicators. Asset performance records include cause codes suitable for analysis. Asset condition is assessed by a combination of age, asset inspection information and expert judgement. Some advanced assessment methods such as partial discharge testing are used. Standards or handbooks exist providing guidance regarding the grading of defects. There is however limited evidence of use of asset condition data for developing forward looking renewal forecasts and plans with the current approach somewhat reactive based on the results of condition inspections. For example, the current AMP provides asset age profiles without reference to asset condition.	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).
99	Investigation of asset-related failures, incidents and nonconformities	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	At present a formal incident management process for asset related failures is not in place. This is manageable given the relatively small size of Network Waitaki coupled with the relatively low frequency of incidents which is also related to the organizations size. Investigation skills exist within the organization with some staff members trained in the ICAMS methodology. Incidents with safety consequences are formally investigated and their outcomes recorded and managed using the Vault risk register system. The new process management system Promap includes the ability for process users to highlight process non-conformities and have these formally recorded and actioned. External experts are engaged to investigate major failures or technical failures outside of the skill set of engineering staff.	Widely used AM 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	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?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	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?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Network Waitaki conducts annual self-assessments using the Commerce Commission's AMMAT framework. The company's public safety management system is also formally audited and certified by an external audit party. The process mapping system Promap includes periodic review and of compliance with processes. There are also periodic audits of field work to ensure safety compliance and work quality. While audit processes are in place, there could be some scope for increased scrutiny of asset management processes and systems and formalization of an internal audit plan.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, 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.
109	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	Network Waitaki has several systems that record actions arising from investigations or non-conformances. These include the system Vault which is associated with risks and safety incidents an an improvement register implemented using the Microsoft planner application. The Promap process mapping system also has an internal mechanism for creating improvement opportunities for implementation. Management meeting minutes are another place where corrective and preventive actions may be recorded. While these mechanisms are in place, they are somewhat distributed and not formalized as would be the case in an ISO9001 type system.	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 businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM 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
113	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	There is evidence of a continual improvement culture in parts of the organization with a general awareness of improvement opportunities and a drive to make progress towards these. Evidence of this can be found in the work to implement a risk management framework and process mapping system. This is not however formalized as a continual improvement action plan encompassing all parts of the asset management system.	Widely used AM 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 that 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.
	Improvement	and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?		regarding asset management related technology and practices through engagement and participation in industry bodies and working groups such as the EEA and ENA and their associated working groups.	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 which does this (eg, 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.	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.	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	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?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	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?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	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?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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Schedule 14a Mandatory Explanatory Notes on Forecast Information

(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 2.7.7. 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. In the box below, comment on 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

Network Waitaki Limited referred to predictions for CPI has been extracted from a combination of Reserve Bank of New Zealand Monetary Policy Statement, February 2023 with an increase due to historical evidence that the Electricity industry CPI results in a higher-than-average rate.

For CY+1 forecast a CPI of 8% was applied. From CY+2 to CY+5 a CPI forecast of 7% per annum was applied. From CY+6 to CY+10 a CPI forecast of 5% per annum was applied.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on 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

Network Waitaki Limited referred to predictions for CPI has been extracted from a combination of Reserve Bank of New Zealand Monetary Policy Statement, February 2023 with an increase due to historical evidence that the Electricity industry CPI results in a higher-than-average rate.

For CY+1 forecast a CPI of 7% was applied. From CY+2 to CY+5 a CPI forecast of 6% per annum was applied. From CY+6 to CY+10 a CPI forecast of 4% per annum was applied.

Appendix D – Board Certification of AMP

Certification for Year-Beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Chris J. Dennison and Michael C. Underhill, being directors of Network Waitaki Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Network Waitaki Ltd prepared for the purposes of clauses, 2.6.1, 2.6.2, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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.

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

Christopher J. Dennison	Michael C. Underhill
Chairman of the Board of Directors	Director
Date: 27 March 2023	Date: 27 March 2023