Asset Management Plan 2023 - 2033

OUR **Vision**

Empowering
Our Community.

OUR **Purpose**

To deliver secure, reliable energy while innovating for our future.

OUR **Values**

Safety

We value health & safety always.

Integrity

We are honest and sincere; we mean what we say and say what we mean.

Accountability

We accept responsibility.

Always built on a foundation of respect.

Contents

01. Introduction

Caroline Ovenstone

Stepping into my role as the Chief Executive Officer of the Alpine Energy Limited Group in 2022 has given me a refreshed appreciation for the challenges and opportunities the rapidly changing energy sector presents us with. The era of just-in-time investment decisions are over, and we need to actively plan and invest in the future of our electricity distribution network. This means we need to think differently, plan better and engage more with our key stakeholders and most importantly, know our customers.

Our Asset Management Plan describes how we will achieve what is needed to deliver secure, reliable electricity to homes and businesses in South Canterbury, while balancing future demand and supply and innovating for our future.

Our corporate strategy and asset management plans are all interlinked and developed with our vision front and centre:

"Empowering
Our Community"

Caroline Ovenstone

Alpine Energy Group Chief Executive Officer

Introduction

The energy sector continues to see significant change due to shifting demand brought on by economic growth, local and national commitments to sustainability and climate change goals, and the emergence of disruptive digital technology. Our purpose remains to deliver secure, reliable electricity across South Canterbury, while innovating for our future.

Achieving this balance requires us to consider rapidly changing customer electricity usage patterns, as well as the introduction of new sources and types of electricity generation. The COVID pandemic has affected the economic outlook of New Zealand. We also face the challenges of talent shortages, rising costs and a changing regulatory environment, requiring us to be agile and adaptive in our approach.

This section describes the purpose and structure of our Asset Management Plan (AMP), sets the context in which the AMP has been prepared, and how our strategy is driving our response to a changing electricity sector.

Our Asset Management Plan

"AMP PURPOSE STATEMENT: Our AMP provides transparency to our stakeholders, customers, and our people in relation to how we make investment decisions and how our asset management practices support the decision-making process through the collection and use of data."

What we cover in our AMP

This AMP sets out our plans for the maintenance and development of our network assets and supporting systems to enable the provision of electricity distribution services across South Canterbury. This AMP documents the asset management practices we use to deliver a safe, reliable, and cost-effective network. It also explains how our network and our service delivery aligns with and contributes to our strategy. As far as practicable, we aim to align with ISO 55000 Asset Management Practices that maximise long-term benefits to our customers.

For the purposes of this AMP, the scope of asset management practices and investment forecasts described is limited to our electricity distribution network and does not extend to the management of assets owned by our subsidiaries or other business units.

We recognise that much of the information contained in this AMP is highly technical because of the complexity of electricity distribution networks and supporting systems. Our AMP this year makes a concerted effort to describe our strategies and activities in ways that are accessible and can inform our stakeholders, customers, and our people about how we manage our network, and our plans to meet future demands. Appendix A provides a glossary of terms.

This AMP is structured to meet the requirements of the Electricity Distribution Information Disclosures (Targeted Review Tranche 1) Amendment Determination 2022 (IDs). This includes additional narrative disclosure requirements added in 2022 as part of the Commerce Commission's Targeted ID Review. Appendix B provides a cross reference table showing how our AMP meets the ID requirements.

AMP planning period

This AMP covers a 10-year planning period, from 1 April 2023 to 31 March 2033. Consistent with Information Disclosure requirements, a greater level of detail is provided for the first three years of this period.

We update and publish our 10-year AMP in March every year.

Managing the uncertainty in our AMP

This AMP has been prepared using the most accurate information available at the time of development, however we acknowledge that customer plans can develop or change, sometimes rapidly.

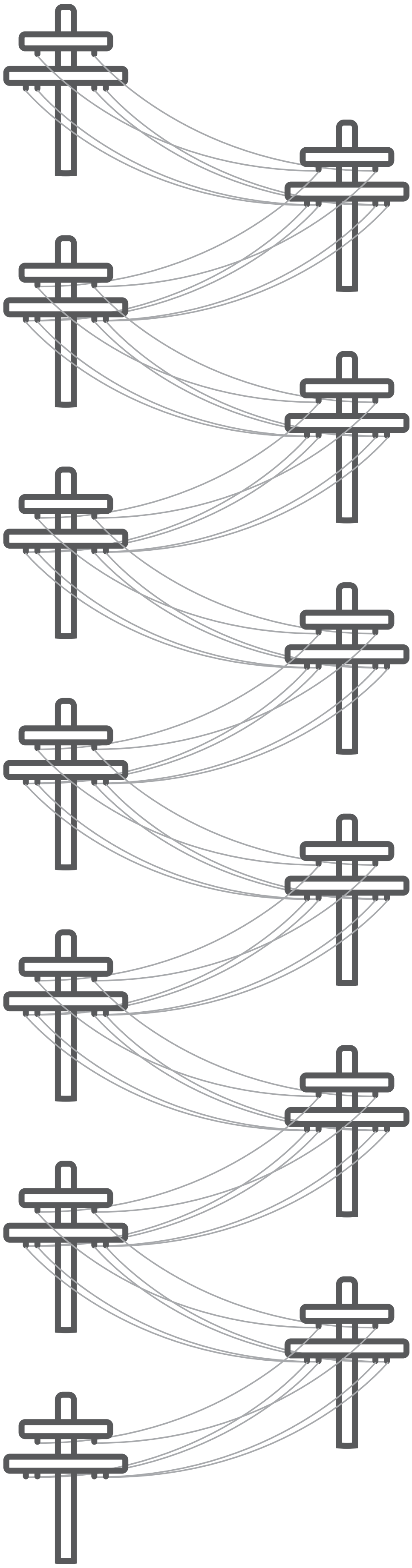
This can have a material impact on plans as set out in this document. We engage closely with customers to support their needs, adjusting and adapting our planning as needed where possible. It is important to highlight that while we are not bound to deliver on the investments detailed in the AMP, any material changes, or new investments that we make will go through the appropriate governance processes to ensure they are delivering against our strategy.

While this AMP looks ahead for the next 10 years, we signal throughout the document that we will need to adapt to changing circumstances, adjusting our planning in both the short and long-term as needed. In developing this AMP, our focus has been on the next three years, with the highest level of certainty in the first year. Beyond three years our forecasts are necessarily more indicative, as we anticipate significant changes in the demands on our network and the expectations of our customers and community.

Certification date

This AMP was certified and approved by our Board of Directors on 6 April 2023. The Directors' Certification is included in Appendix F.

Navigating our AMP



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Our context

As a mid-size non-exempt electricity distribution business (EDB) in New Zealand, we are facing considerable network developments, partly because of the unique makeup of our region and its economic activities. This AMP acknowledges that continuing to provide long-term benefit for our customers and communities will require a step change in our business and operations.

Our unique region

As a region, South Canterbury is uniquely diverse and complex in its electricity needs:

- Diverse land use and economic activities: Dairy, sheep and beef, and crop farming, significant food processing and other industrial operations, and high tourism activity in the Mackenzie District
- Diverse energy demand: Significant industrial process heat requirements combined with seasonal demand driven by irrigation
- Diverse geography and climate: Stretching from the alpine village of Aoraki/Mt Cook to the temperate coast at the Waitaki River
- Diverse population spread: One significant urban centre (Timaru) and many smaller towns and villages throughout the region as well as remote rural connections
- 7 Grid Exit Points (GXPs)

A changing electricity industry

The electricity industry continues to see significant change with shifts in demand and external pressures including:

- The need for the electricity industry to support zero carbon goals and to prepare for a climate-impacted world
- The continuing development of new technologies which enable customers to be more active in generating, storing, and using electricity
- A dynamic regulatory environment which is also seeking to respond to these pressures and support the energy sector's transition to a low-carbon, technology-centric future

As a result, our network, and how we plan and manage it, must address:

- Increased complexities in balancing supply with demand in real-time to ensure the quality and reliability of supply
- Greater peaks and troughs in demand, for example, from the mass uptake of electric vehicles (EVs), small- and large-scale solar generation, and process heat conversion (decarbonisation through electrification)
- Distributed generation (DG) increasing two-way flows of electricity, creating new safety and technical issues
- The need for greater resilience to address the potential impacts of climate change and an Alpine Fault rupture on our assets

We need to be agile and ready to enable the significant increase in electricity required for South Canterbury to meet decarbonisation goals. We must also manage the increasing demand for connection of DG to our network, all while maintaining a resilient, reliable and secure network and enabling business and household growth in the region.

Climate resilience has never been more important due to the growing threat of extreme weather events, climate change-related risks, and natural hazards. The devastating impact to North Island communities from recent weather events highlights the interdependence of lifeline utilities, particularly electricity and telecommunications. It also shows just how critical the electricity network is to community safety, emergency response and recovery during severe weather events and natural disasters. We must take proactive steps to understand the climate resilience of our network and our communities.

Our customers are also changing. Many want to be active participants in this new electric world, producing, consuming, storing and selling electricity though household DG connections. They also want access to better and faster information about their electricity, whether it is through tracking the output of their rooftop solar panels or following the progress of fault restoration in real-time, or opportunities to improve their electricity efficiency. Our network and our systems need to be fit for purpose to meet these customer expectations.

Technology now provides opportunities for innovation right across the electricity value chain, from generation through to customers. We need to ensure we invest in the right technology opportunities to better optimise our network and our services.

The capabilities of our team will need to evolve, and our team will need to grow to deliver new requirements of this changing electricity sector. We also need to engage in a more deliberate way with our regulators and peers, to ensure our interests, and the interests of our industry are represented in decision-making processes.

Our role in decarbonising South Canterbury

The government's goal of net-zero emissions by 2050 is changing how New Zealanders live and work. Decarbonisation is achieved by transitioning to low carbon energy sources and is a key driver of transformational change across all industries. The electrification of transport and industry is critical to achieving decarbonisation goals, and we have a significant role in enabling this.

To facilitate large-scale process heat decarbonisation projects, the government has implemented a series of climate-related policies, including a $650 million Government Investment to Decarbonise Industry (GIDI) fund, and the banning of new low and medium temperature coal-fired boilers.

In 2022/2023 we completed our first major industrial decarbonisation project, supporting a customer to transition from coal fired boilers to electric boilers and have supported the phasing out of coal-fired boilers for South Canterbury schools and the Timaru Hospital as part of the Carbon Neutral Government Programme, over the last three years.

Other government policies, including the Clean Car Discount, which became available in July 2021, will continue into the foreseeable future. The discount scheme will further contribute to the growing uptake of EVs in South Canterbury which will lead to increased demand on our low voltage (LV) network.

We are receiving increased enquiries in relation to industrial decarbonisation and medium and large DG projects. We are also engaging with an increasing number of commercial and residential customers on the installation of small-scale DG (mainly rooftop solar photovoltaic (PV) units), and EV chargers.

We are also working to ensure that our network is designed to leverage technology that helps reduce our own carbon emissions, and effectively manages our supply chain. The use of new technologies such as drones and remote switching technology can reduce travel and our reliance on fossil fuels. We are also designing our network so that equipment supply chains are short, or circular where possible. A well-designed network is resilient and efficient, and we expect to see these measures reduce our operational costs, particularly as the cost of fossil fuels are forecast to increase.

Project – WoolWorks New Zealand Limited Decarbonisation

WoolWorks, the world's largest wool scourer in terms of volume, handles 76% of New Zealand's wool, washing over 100 million kilograms of wool annually across their three sites. Despite the energy-intensive wool scouring process, WoolWorks has been committed to sustainable practices since 2016. Their latest project involves replacing coal with electricity to power their Timaru site, with co-funding from the GIDI Fund.

This project included the installation of an 8.5MVA electrode boiler and an industrial heat pump, expected to reduce over 11,000 tonnes of carbon dioxide emissions annually. In 2022 we worked closely with WoolWorks to ensure that our network could enable their decarbonisation goals.

Through this project, and others like it in the future, we are proud to be living our vision of empowering our community.

Enabling distributed generation

DG provides both increasing complexities and opportunities for us. We have already started to see this materialise in South Canterbury with a notable increase in enquiries and applications received for DG connections. Enabling DG on our network will require both the adoption of technologies for demand response, and innovative business and pricing models.

As further policy direction is provided by the Government on the future of energy, we will continue to look for ways to facilitate the connection of DG across our network, while providing an equitable pricing framework for all customers.

Enabling electrification

With the need to transition away from carbon and non-renewable resources, we anticipate a significant move to electric nationally and locally. This will support individuals, households, and businesses as they reduce their own carbon emissions.

We have already seen an increase in the number of EVs on our roads, largely from local businesses replacing existing fleets with EVs and commuters and tourists passing through our network, rather than residents. This increased demand requires a significant uplift in our network capacity over the coming years and strong collaboration with our stakeholders to facilitate the delivery.

We anticipate seeing further increasing electricity demand from the conversion of industrial process heat, the uptake of EVs and the decarbonisation of transportation and changes to how we heat our homes due to air quality regulations.

A time of digital disruption

Digitalisation is not just about improving our operational efficiencies and enhancing customer experience, but also about using data to enable better decision-making, and risk management. The use of data can streamline our risk assessments, improve our designs, help us manage our asset lifecycles better, and improve the resiliency of our network. Embedding digital ways of working will provide value to our staff and customers and optimise our core processes and workflows as we face the future.

Technology and data need to be entrenched in every part of our business. A traditional business model where information technology (IT) computing is separate from the operational technology (OT) of wires, substations, transformers, and other field equipment will no longer be sufficient. IT and OT will need to converge. By centralising our data and technology systems, we will be able to make better use of the data generated by our operations and our business systems. This will help us to identify risks and opportunities in real-time, and to respond more effectively to changing conditions.

To minimise this disruption and benefit from digital advances we must streamline key business processes, have data and technology central to our business decisions and the way we work. Our Digital Services team will support the focus on identifying and improving our key processes using automation and optimisation where it provides value.

As our use of technology increases, so do cyber security threats. Our cyber security strategy has been in place for over two years, and significant work has been put in place internally and with our key partners to move toward the objectives of sound enterprise architecture practices, informed and trained employees and an adherence to critical infrastructure industry frameworks.

Our response to extreme weather events

Our customers value reliable service. The biggest obstacle to providing reliable supply is caused by extreme weather events. Strong winds, wildfires, heavy snow and rain, and other extreme weather events can cause damage to our infrastructure and result in unplanned outages.

With the impacts of climate change already being felt, our future environment is one in which these events will become more frequent and more extreme requiring that we build resilience into our systems and response capability. Improvements to mitigate the impact of extreme weather events and adapt to climate change will begin to feature in our network planning and capital programmes.

Our response to an Alpine Fault event (AF8)

Research by Te Herenga Waka – Victoria University of Wellington estimates that there is a 75% chance of a major Alpine Fault earthquake in the next 50 years. This poses a high-impact risk to our infrastructure, capable of causing significant damage and prolonged outages throughout the region and the South Island. We must evaluate the requirements, quantities, and storage locations of our critical spares to enhance our response capabilities. Our dedication to building resilience into our systems encompasses these low-probability, high-impact events, and we will continuously explore ways to prepare for any eventuality.

Regulatory environment

A recent Boston Consulting Group report estimates New Zealand must spend $22 billion over the coming decade in electricity distribution infrastructure alone to manage both the impacts of climate change and the growth in demand for electricity, including the rapid electrification of transport and industry.

To deliver on this, our regulatory framework, including regulated expenditure settings, need to evolve to reflect our essential role in the energy transition, and the need for greater investment in climate resilience.

Talent gap

The current talent gap, i.e., our ability to hire, retain, train, or outsource the competencies we need to deliver our AMP, is one of the key risks to our successful delivery of our AMP and strategy as a business. The competition for talent is further exacerbated by the diversity of skills we must develop to deliver our future growth. High-growth sectors like ours are competing for skills in technology, infrastructure, and other key areas.

To mitigate these risks, we have implemented several initiatives to develop and retain our staff, such as offering training and development programs, flexible work arrangements, and creating a supportive and inclusive workplace culture.

However, we recognise that the talent gap is a significant and ongoing obstacle, and we will continue to monitor the market trends and adjust our people strategy accordingly. By proactively addressing the talent gap, we aim to ensure that we have the right people in place to support our growth and success in the years to come.

Our strategy

Our strategy is central to how we respond to the changing sector we operate in and provides the direction for this AMP.

With this in mind, our strategy is built around the key trends and changes that will impact our business and our asset management practices in the short, medium and long-term. We have identified our key strategic influences as:

OUR **Scope**

We own and operate the electricity distribution network that provides South Cantabrians with power. Our subsidiaries are primarily engaged in related electrical contract services.

We are proud to be community-owned and connect over 33,500 customers throughout our region. We are considered an essential lifeline service, playing a significant role in our community, contributing to the growth and prosperity of South Canterbury and New Zealand's transition to a low-carbon economy.

Problem statement: To dynamically balance energy supply and demand in the South Canterbury region. This balance needs to consider rapidly changing customer energy usage patterns, and the introduction of new sources and types of generation.

Aspiration: We must be able to dynamically balance energy supply and demand in the South Canterbury region. This balance needs to consider rapidly changing customer energy usage patterns, and the introduction of new sources and types of generation. We are a "best-in-class" EDB with a strong capacity to fast follow on key trends, and our operational excellence will form a baseline from which we can identify and adopt new commercial opportunities.

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OUR **Focus**

Serving Our Current Customers Well	Providing Excellent Core Services	Future State: Selected New Customers & Services

OUR **Strategy**

Our 5 strategic pillars	SP1: Customer Experience	SP2: Future Networks	SP3: Digital & Data	SP4: Operations	SP5: Sustainability
Our strategic goals **What will our future state look like?**	We will deliver exceptional customer experiences enabling our customers to make informed energy choices.	We will build a mature asset management process to ensure our assets are best placed to meet our customer's future needs.	We will treat our data as a strategic asset and use technology to transform our customers' and our people's experiences.	We will deliver electricity to South Canterbury homes and businesses while balancing future supply and demand.	We will work with the local community to improve South Canterbury's social, economic and environmental wellbeing.
Why is this important?	This will ensure that we always put our customers first.	This enables us to build a network for the future, not for the now.	This will transform the way we work to make the right decisions for our customers and our people.	This ensures that we can keep our community reliably connected now and into the future.	This ensures we are on the same journey as our stakeholders and customers, supporting a sustainable future for South Canterbury.

Our key strategic enablers	SE1: Stakeholder engagement	SE2: Employee Experience	SE3: Safety	SE4: Operating Business
Our enabling goals **How will this enable us to deliver our strategy?**	Strong partnerships with external stakeholders and the community will ensure shared success and delivery of our strategic goals.	Attracting and retaining top talent will provide us with the resources and capabilities we need to achieve our strategic goals.	Because we care for our people and our community ensuring everyone goes home safely every day is our number one priority.	To deliver value for our customers and Shareholders requires sound business processes and procedures.

Expenditure forecasts

Capital Expenditure

Over then next 10 years we are forecasting total network capital expenditure (CAPEX) of $277 million. This is a significant increase on our previous AMP forecast, as Figure 1 shows. It reflects our response to the influences of our key investment drivers (discussed in Section 3). It also reflects the inclusion of some significant projects in our plan including:

- New substations at Washdyke and Timaru Port, to support forecast load growth from the electrification of industrial process heat
- The replacement of end-of-life substation equipment and transformers in Twizel, Tekapō, Pleasant Point and Fairlie
- Upgrading our Timaru urban network at North Street Substation and Sophia Street Switching Station to resolve capacity constraints, support future EV growth and improve network resilience
- Increasing our inspection and replacement of aged LV boxes to reduce fire risk and improve the resilience of our LV network

These projects, and our full CAPEX programme are designed to ensure we can meet forecast demand from industrial and residential load growth. They also support maintenance of safety levels and network resilience. Section 11 provides more detail on our forecast expenditure, including our material project and significant variances from our previous AMP.

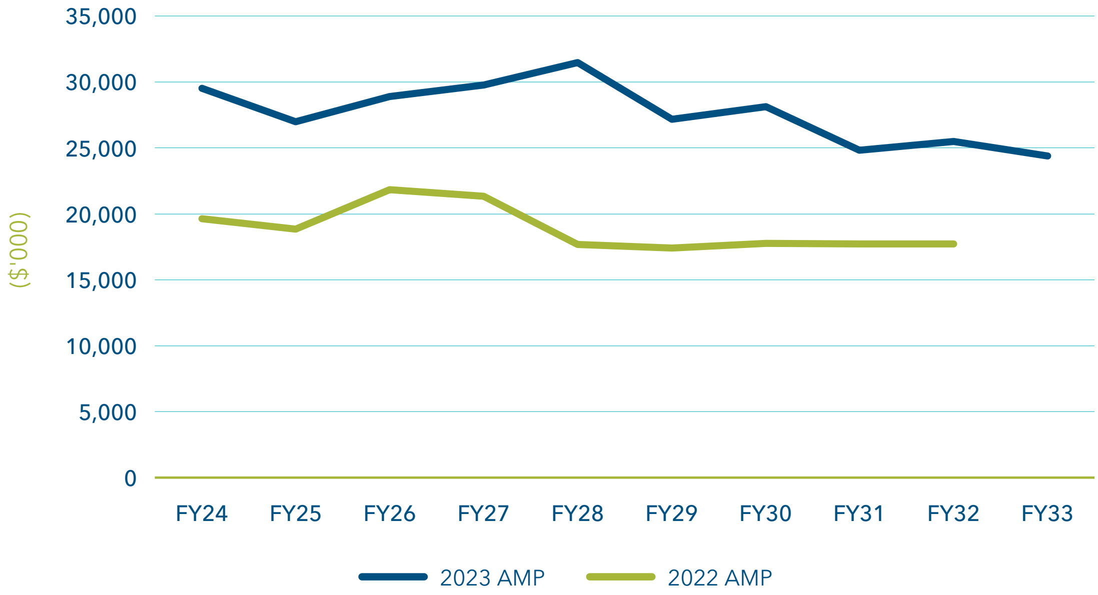


Figure 1: Network CAPEX - 2023-33 AMP versus 2022-22 AMP.

Our total forecast non-network CAPEX is $27 million over the planning period. This represents a significant investment in the digital tools we require to support and run our network, now and into the future. Section 9 details our planned investment in digital.

Operating Expenditure

Our network operating expenditure (OPEX) has increased to $70 million over the 10 years as we continue to invest in our programme of network inspections and monitoring. This increase is largely driven by our vegetation management portfolio, with rising labour costs and a planned increase to our vegetation inspection programme to improve network resilience.

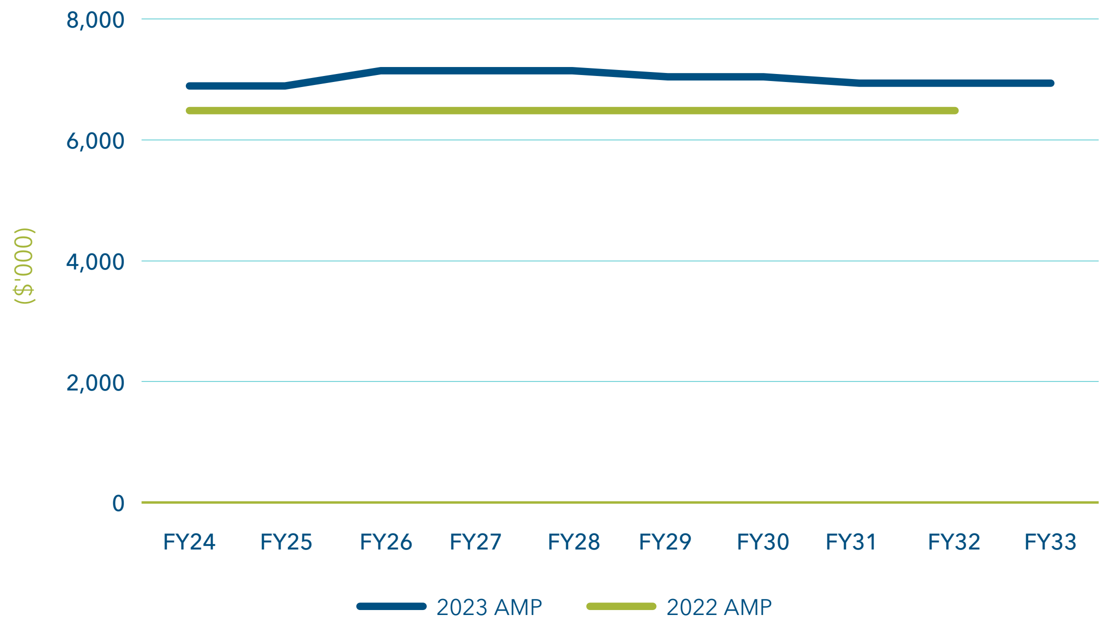


Figure 2: Network OPEX - 2023-33 AMP versus 2022-22 AMP.

Our non-network OPEX has also increased to $227 million over the ten years, driven by increased investment in our people and capabilities.

Section 11 provides a full overview of our forecast expenditure across this planning period.

Corporate and strategic documents

Our AMP forms part of a suite of documents, policies and plans which guide our strategic direction through to operational planning requirements. The AMP is a key link between our other documents, translating our corporate and strategic documents into operational delivery.

Statement of Corporate Intent

Our Statement of Corporate Intent (SCI) is prepared at a Group level and takes direction from our Strategy and our Shareholders' expectations. Our SCI sets out our key roles as a Group and a business, the scope of our governance and relationship to shareholders, and the Group's intentions and performance targets for the next three financial years.

In accordance with Section 39 of the Energy Companies Act (1992), we submit a draft SCI to our shareholders prior to each financial year. After considering shareholders' feedback on the draft, our Board approves our final SCI.

Annual Report

Our Annual Reports offer a review of our previous year, our performance and whether we delivered on our plans and performance measures. These relate back to the intentions of our AMP and our SCI.

Supporting plans

We hold several other policies and plans which support our business and operations, including our Health and Safety Policy, Risk Management Policy, Participant Rolling Outage Plan and Emergency Preparedness Plan. Where appropriate, these have been included in our asset management planning.

02. About Alpine Energy

About Alpine Energy

We proudly own and operate the electricity distribution network in South Canterbury.

This section provides an overview of our network and our group structure.

Our network

We are a non-exempt EDB and must comply with the Commerce Commission's Default Price-Quality Path (DPP) Determinations . We proudly own, maintain, and operate the electricity distribution network that delivers electricity to over 33,500 homes and businesses in South Canterbury. We deliver an essential lifeline service which is critical to support our region's economic growth. We also have an important role to play in New Zealand's transition to a low-carbon economy.

Our network stretches over 10,000km^2 of South Canterbury bounded between the Rangitata River to the north and the Waitaki River to the south. Our network extends west to the Southern Alps as far as Aoraki/Mt Cook Village, while the coast is the natural eastern boundary, as shown in Figure 1.

We have seven GXPs on our network as shown in Figure 1 below. The full overview and network configurations and schematic diagram for each GXP is included in Appendix C.

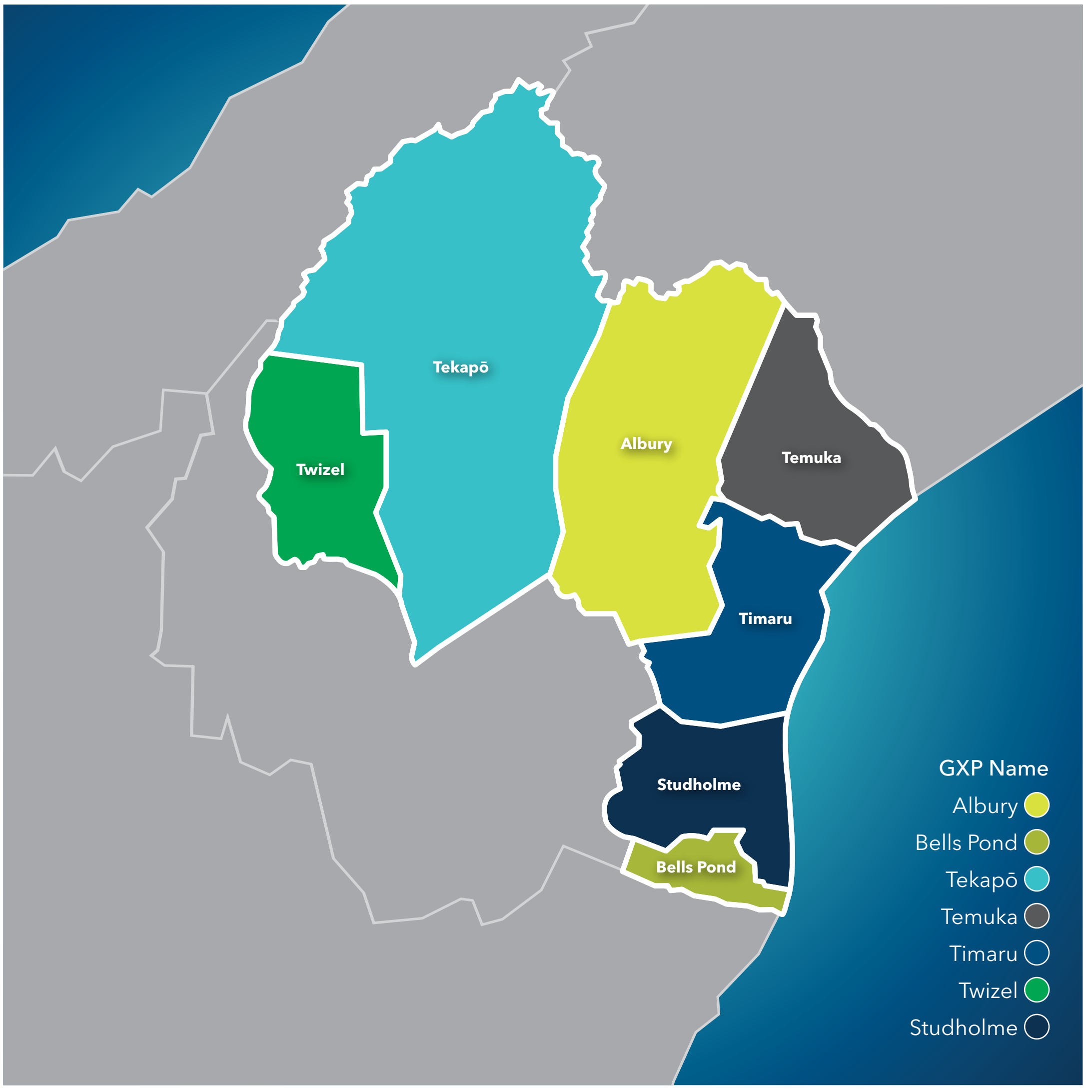


Figure 1: Our Region.

Our role in the electricity value chain

Figures 2 shows our role in the electricity value chain.

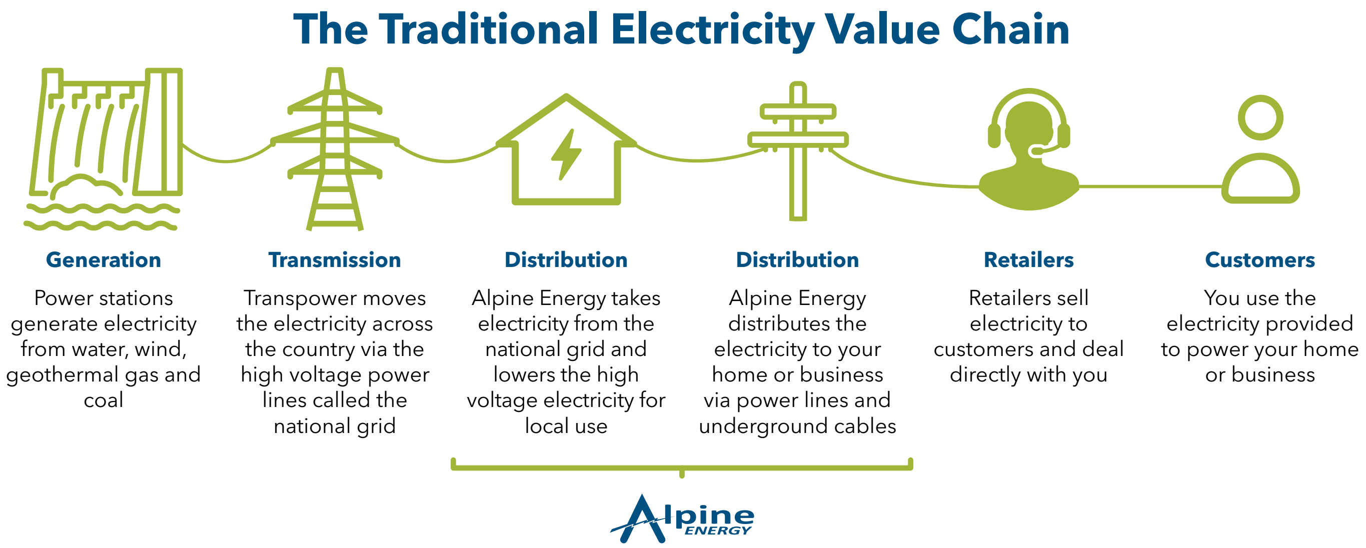


Figure 2: Our role in the electricity value chain.

Our network connects to the Transpower transmission grid at GXPs, where bulk supply is taken and transferred to lower voltages via power transformers. The GXPs operate at voltages of 110kV, 33kV and 11kV.

Electricity then flows through the sub-transmission and distribution networks to zone substations and distribution substations where the electricity is converted to LV as the form predominantly used in homes and businesses.

Our network is comprised of overhead lines and underground cables rated at 110kV (but operated at 33kV), 33kV, 22kV, 11kV, and 400/230V. Voltage levels are used to distinguish between the distinct networks as:

- Sub-transmission – 110kV, 33kV, and 11kV
- Distribution – 22kV and 11kV
- LV – 230V single-phase and 400V three-phase networks

In some instances, we step up distribution voltages to sub-transmission voltages for transmission to some of our zone substations.

However, the traditional electricity distribution role, as described above, is changing. Increasingly we need to:

- Manage growing energy demands due to decarbonisation and economic growth
- Utilise new and smarter technologies to enable muti-directional energy flows due to large- and small-scale DG
- Develop greater visibility and control over our LV network to enable customers to become active participants, i.e., produce, consume, store and sell electricity
- Proactively engage with our customers and stakeholder to meet their energy needs and expectations

While we embrace the prospects, demands and challenges of the future, we are conscious that we must also continue to provide long-term benefits to our customers through robust asset management planning, and service delivery at a quality that reflects the needs of our customers.

We are committed to delivering on both fronts. We will innovate and adapt to meet future demands, and we will continue to invest in our existing network and our core role of delivering a safe, reliable, and resilient network.

Our organisation

We are owned by Timaru District Holdings Limited (TDHL) (a subsidiary of Timaru District Council), LineTrust South Canterbury, Waimate District Council, and Mackenzie District Council. This ownership model ensures that we deliver long-term benefits and cost-effective services to the South Canterbury community.

Network Ownership

LineTrust South Canterbury	Timaru District Holdings Limited	Waimate District Council	Mackenzie District Council
40%	47.5%	7.54%	4.96%

The South Canterbury community owns 100% of Alpine Energy

The Alpine Energy Group includes unregulated investments in subsidiaries and joint ventures. The core business of our principal subsidiary, NETcon Limited, is the construction and maintenance of our electricity distribution network. SmartCo is a vehicle for the growth of critical network data insights needed for our future growth.

03. **Our AMP drivers**

Our AMP Drivers

We are facing uncertainty at unprecedented levels around future electricity demand, the impact of climate change, technological advances, and the extent of regulatory change required to support a transformed energy sector. Identifying long-term investment drivers, and making key assumptions is critical to our planning process.

This section outlines the long-term investment drivers and the significant forecasting assumptions we used to develop our AMP.

Long-term investment drivers

Like other EDBs across New Zealand, we need to enable New Zealand society to decarbonise through electrification, particularly in the transport and industrial sectors. Our national journey to Net Zero 2050 will take us and all our customers through a transition. As we embrace this future, we need to consider a range of changes to electricity demand and supply - from EVs and new residential and commercial development, through to changes in industrial processes and electricity supply.

While all New Zealand is united in achieving the same goal, each EDB has different drivers and responses. In this section, we outline our drivers, and their potential impacts on our investment decisions beyond this AMP period. While some align with known targets and timeframes, we must consider the scale and timing of future customer decisions, particularly those further into the future. We have made an informed assessment of our investment drivers over the next 10 years, based on our assumptions, and will continue to monitor and adapt our plans. Future AMPs will prominently feature these drivers.

As well as these new investment drivers, we will continue to prioritise our business-as-usual maintenance programmes and core service delivery to ensure that we continue to provide safe, reliable electricity to South Canterbury.

Decarbonisation through industrial process heat conversion

To support our planning, we engaged energy consultants DETA, in partnership with Transpower, the Ministry of Business, Innovation and Employment (MBIE) and the Energy Efficiency and Conservation Authority (EECA). Their analysis has informed our demand forecasting in Section 7 and identified the future load requirements of 26 sites within our region currently using non-renewable fuel for heat generation, with installed capacity exceeding 500kW.

With the presence of large-scale regionally and nationally significant industry within our region, we plan to enable conversion of industrial process heat to help decarbonise the economy. This will require a significant acceleration of energy efficiency and fuel switching projects, particularly as a key target requires 100% of coal boilers to be phased out of the economy by 2037.

Enabling conversion of industrial process heat may require significant effort from us in the short- to medium-term, while we build the capacity to meet the demand. The most significant pressure will come from the three dairy factories within our supply area, most notably Fonterra's Clandeboye site.

We are currently working with our customers to gain an understanding of their conversion plans to enable us to respond accordingly. This new driver is anticipated to have the greatest impact on our planning and required investment, in partnership with Transpower.

Population and household growth

Population growth has been a historic driver of network planning and investment. Housing pressures, both national and locally, and the need to protect highly productive land, have led to increasing demand for infill development and continued greenfield development.

We will continue to monitor population growth and demand and align our planning with our territorial authorities' spatial and district planning. We will pay close attention to the developments within Twizel and Tekapō, as these LV networks have the most capacity constraints.

New commercial and industrial loads

Commercial and industrial loads are currently our largest source of growth. Through engagement with our customers and local businesses and councils, we expect this commercial and industrial growth to continue which will require a step change in our investment to meet the growing demand.

The Proposed Timaru District Plan identifies development areas, concentrated at Washdyke, and industrial development is being explored by both Waimate and Mackenzie District Councils. This therefore remains a key component of our planning.

We encourage early engagement from developers, and commercial and industrial industries with connections needs.

Electric vehicles

To achieve net zero CO_2 emissions by 2050 New Zealand needs to significantly improve transportation fuel efficiency and reduce these emissions. The Government's Clean Car Standard and the Clean Car Discount work together to improve the supply and the demand for low and zero CO_2 emission light vehicles entering New Zealand.

The effects of these policy changes are evident with a national EV sales tipping point predicted in 2025. EV range increases, coupled with price decreases will make EVs both a practical and economically sensible choice for an increasing range of customers.

Our customer survey noted a significant shift in the anticipated EV uptake within South Canterbury within the next five years, which we will continue to monitor. While our local EV uptake is at a slower rate than metropolitan areas, we forecast that our location on major arterial routes, and the significance of tourism in the Mackenzie District will escalate demand for public charging stations within our region.

We have worked with local stakeholders and government agencies to ensure that initial EV charger network coverage is in place. As EV uptake increases, and as more throughput is experienced due to EV drivers travelling within our network area, it is expected that there will be a requirement for more multiple charger stations and more hyper rapid chargers (150+ kW DC).

Using recent UK developments as a guide for what can be expected in the medium-term in New Zealand, large-scale cluster charging can be expected, with service stations offering a range of chargers for customers, including hyper rapid chargers, and much greater home charging of EVs is also expected. These expected medium-term developments provide investment opportunities and considerations for us.

Further modelling is required to determine the expected impacts of 7.4kW and 22kW EV home charging on the LV network, with subsequent network changes anticipated. Increased LV visibility will be necessary to provide us with EV switching ability to manage load. The use of smart meters on our network will greatly benefit us in obtaining this LV visibility.

In March 2023, the Ministry for Transport released a draft EV Charging Infrastructure Strategy - *Charging Our Future*. Our engagement with the Ministry on this Strategy will focus on ensuring a joined-up approach to planning a future EV charging network across our region. As the Strategy is rolled out, we will work closely with key stakeholders, including local councils, charging providers, developers and businesses to support long-term positive outcomes for our network, and for our communities.

Residential and commercial gas conversion

We do not anticipate that in South Canterbury changes to the LPG supply will cause a major load shift to electricity within the next thirty years.

Our most recent customer survey identified 21% of respondents use gas for hot water or heating. This was highest amongst rural commercial customers. We do not hold statistics on those using gas for cooking. Gas supply within South Canterbury is via bottled LPG, with no natural gas or reticulated gas supplies.

Although fossil fuels and LPG gas have been identified as contributing to New Zealand's carbon emissions, there is no phase out date for the use of them proposed in current government policy. A future decision of government may, furthermore, restrict new installations of LPG fuelled infrastructure. The gas sector is committed to exploring BioLPG or new low or zero carbon gases. The transfer of all customers to either electricity or other gases are anticipated by 2050. We will continue to engage with the gas industry and monitor government requirements.

Grid-scale solar and wind

We anticipate that future grid-scale solar and wind generation will contribute to our supply network. In addition to the increasing demand for connections to our LV network, DG provides us with both benefits and complexities. At the time of preparing this AMP, we had received over 100MW of DG applications. Enabling DG on our network will require the adoption of technologies for demand response, energy storage, and innovative business and pricing models.

We anticipate that developments will continue at a moderate level, and that our network must be adaptable to support grid-scale generation and energy storage. We will continue to engage with potential solar or wind generators and adapt our infrastructure planning as necessary.

Extreme weather events and climate adaptation

The impact of extreme weather events on electrical infrastructure highlights the importance of climate change-related risk and resilience to our business and our communities.

This risk was highlighted by cyclone Gabrielle in February 2023. Gabrielle caused extensive damage to electricity distribution networks across the North Island, resulting in widespread power outages and property damage.

In the context of this AMP, climate resilience refers to the ability of the electricity network to anticipate, absorb, accommodate, and recover from the effects of potentially hazardous events related to climate change, and our ability to mitigate climate related risks like those identified above. We recognise the need to improve the resilience of our network to minimise the impact of extreme weather events on our customers.

To this end, we have begun work to better understand our network-related risks and improve our resilience. In 2022 we assessed over 45,000 poles across our network, drawing on data from National Institute of Water and Atmospheric Research (NIWA) and others, using a broad range of risk factors. This has enabled us to reprioritise our pole inspection and maintenance schedules to improve our network's resilience to climate-related risk and other risks.

We will continue engaging with NIWA to apply climate change predictions to these risk factors to further support our resilience planning.

In 2023, we plan to commence a climate change-risk assessment across our business and our network. This work will provide local and network specific context for the risks identified in the New Zealand, and Canterbury Climate Change Risk Assessments. This will support a greater level of risk and opportunity identification and enable us to develop adaptation strategies with the appropriate metrics and targets to respond. We have also committed to undertaking annual voluntary climate-related risk disclosures. Our first disclosures were included in our 2022 Annual Report.

New Zealand Climate Change Risk Assessment

The first New Zealand Climate Change Risk Assessment, and the Canterbury Climate Change Risk Assessment, both published in 2022, provide an indication of our significant and priority risks including:

- Risks to electricity infrastructure due to changes in temperature, rainfall, snow, extreme weather events, wind, and increased fire risk
- Risks to buildings due to extreme weather events, drought, increased fire risk and ongoing sea-level rise
- Risks to transport networks, due to changes in temperature, extreme weather events and ongoing sea-level rise, with a secondary risk of loss of access to allow timely repair to any network damage
- Risks to the ability of the emergency management system to respond to an increasing frequency and scale of compounding and cascading climate change impacts
- Risks to businesses and public organisations from supply chain and distribution network disruptions, due to extreme weather events and ongoing, gradual changes
- Risks to the insurability of assets, due to ongoing sea-level rise and extreme weather events
- Risks to the financial system from instability due to extreme weather events and ongoing, gradual changes

Low voltage visibility

While we have good visibility of our high voltage (HV) network, we have limited oversight of our LV network stepping down to connections into homes and businesses. Our smart metering network, covering more than 88% of our installation control points (ICPs), plays a pivotal role in providing access to these new datasets we will need to identify opportunities, and provide a platform for distributed energy resource (DER) management into the future.

Flexibility services, outage management, and network modelling will be enabled through our investment in SmartCo, who are currently developing a suite of tools to address this need. Taking a holistic approach to data and digitisation is essential in building an optimised energy system for South Canterbury.

Improved visibility and monitoring of our LV network will enhance our asset management practices ensuring that our supply is reliable, and that voltage and frequency meet our defined supply quality standards. Appropriate systems and processes will support us in adapting to significant shifts in production and use of electricity over the next three decades.

This work will also support us to appropriately manage increased operational complexity, power quality (voltage levels compliance) and safety risks, which may arise from the uptake of technology such as solar PV panels, batteries, and significant new loads such as those created by EV charging into the future.

Enhanced, real-time ability to monitor LV network status and performance will be critical for the safe, secure, and reliable supply of electricity for homes and businesses within our communities.

Funding complexities

Our ability to deliver the step change outlined in this AMP is reliant on our future regulatory allowances being sufficient, or our ability to raise sufficient capital for investment.

The DPP4 consultation process is expected to be finalised during 2024, and will commence on 1 April 2025, covering the next regulatory period (five years). As a result of this timing, there is currently uncertainty over our future revenue and our ability to fund increased CAPEX and OPEX to service the demand on our network. Other funding complexities persist due to the impact of inflation assumptions that have systematically over-forecast inflation for a decade, reducing our revenues below the forecast return. The effect of these assumptions on our funding has been significant, and with radically different inflation expectations since DPP3 was determined in 2019, this impact is likely to be further compounded until 2025.

Given that our own costs are increasing, we remain mindful of energy affordability for our customers, particularly as energy poverty is a real concern in New Zealand, especially in the current economic climate.

Our ability to deliver

Translating this AMP into completed work is essential to delivering the step-change required to enable decarbonisation and growth in South Canterbury and meet our customers' energy needs and our strategic goal. This will need a targeted focus on how we deliver our full programme of work and initiatives.

Like other industries, we are facing supply chain challenges, inflationary pressures, and a compressed labour market. We need to identify and build the right capabilities internally and support our service providers to do the same. Increased collaboration with customers and key stakeholders, including our service providers and other utilities providers, as well as innovative procurement approaches, will be essential to the delivery of our full programme of work and initiatives.

Impacts and anticipated timing of long-term investment drivers

We have assessed the impacts and anticipated the timing of these long-term investment drivers on our network and service delivery as summarised in Figure 1.

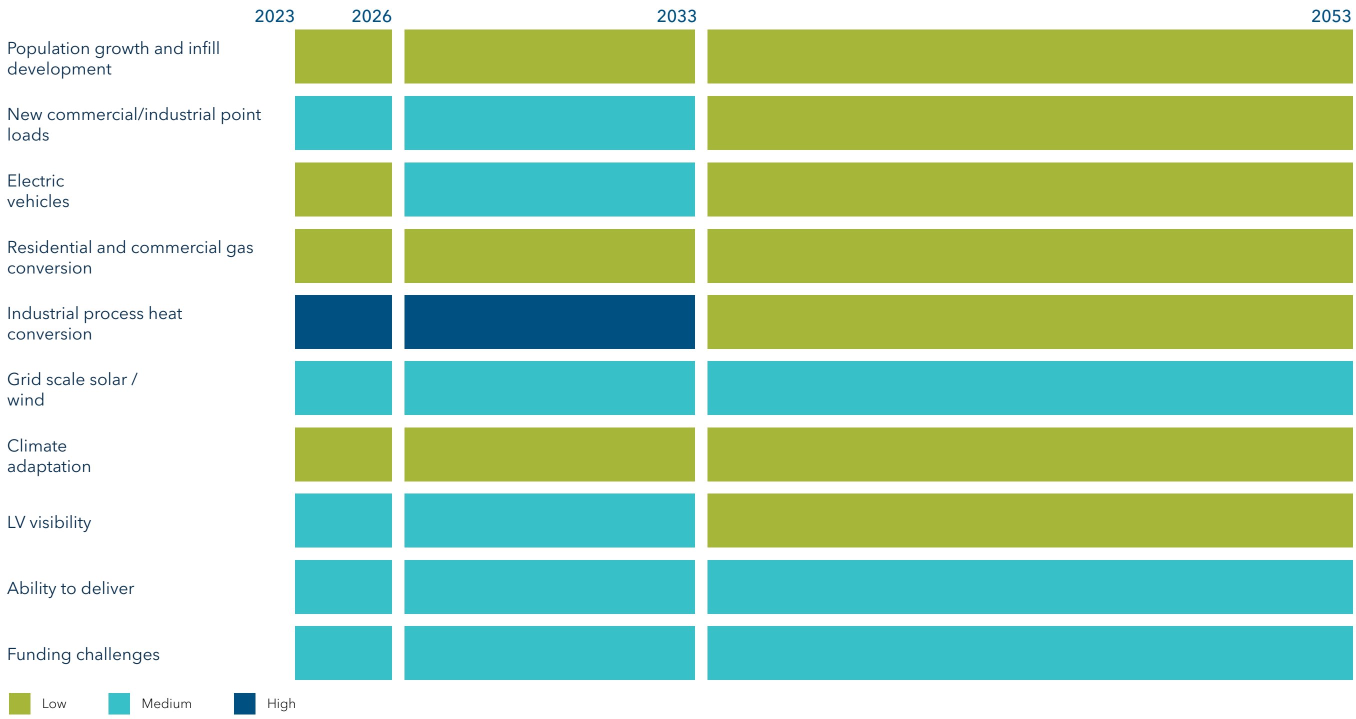


Figure 1: Long-term investment drivers' impact.

Forecasting assumptions

Our significant forecasting assumptions have been applied to our asset planning, projects, and financial planning outlined in this AMP.

Population, household, and economic growth

Our Assumption: Population and household growth across South Canterbury is assumed to be in line with the growth projections prepared by the Timaru, Mackenzie and Waimate District Councils.[1]

The Mackenzie District will see the highest rate of growth across the region during this AMP period. This growth will predominately occur in Tekapō and Twizel urban areas. The Timaru and Waimate Districts will see smaller increases in population and households across the planning period.

We assume economic development across the region will remain consistent with recent positive trends. We do not assume any significant land use change to drive rapid economic growth, or any significant long-term economic decline across the region.

We assume that historical relationships between population, household and economic growth, and load growth will continue to apply in the short-term.

Our Response: Our Network Development Plans and resulting 10-year forecasts have been developed on this assumption. We will continue to monitor these trends carefully. Our more technical load growth assumptions and inputs are discussed in Section 6.

Regulation and legislation

Our Assumption: We assume that regulatory and legislative change across the period of the AMP will have a significant impact on our business, including new compliance and reporting requirements. Many of the regulatory reviews underway are considering the future role of distribution networks in the electricity market and the promotion of reforms to electricity distribution pricing. These reviews are also focused on how the electricity sector, including distributors can support national zero-carbon goals. Known or signaled regulatory and legislative changes that will impact us during the AMP period include, but are not limited to:

- Commerce Commission's review of Input Methodologies (IMs)
- Commerce Commission's review of IDs
- Commerce Commission's Default Price-Quality Path review (DPP4)
- Electricity Authority's (EA) Distribution Pricing Reform
- National Energy Strategy

We also assume that broader central government policy programmes over the period of this AMP will have a significant impact on customer and stakeholder expectations and behaviour. These include, but are not limited to:

- Emissions Reduction Plan implementation
- National Adaptation Plan implementation
- Resource Management Reform

Our Response: We will continue to actively monitor and engage constructively on reform programmes and regulatory and legislative changes to ensure we are best placed to influence and respond.

[1] **Mackenzie District**
Usually resident population annual average growth: 2.5 % (161 people annually) 2020-2030
Total dwelling annual average growth of 2.9% (122 dwellings annually) 2020-2030. (Source: Mackenzie District Council Growth Projections 2020)

Timaru District
Usually resident population annual average growth of 0.7% 2020-2031
Household growth average annual growth rate of 1.1% (2267 additional households by 2031) (Source: Timaru District Council Long-term Plan 2021-31)

Waimate District
Usually resident population average annual growth 0.4% (35 people annually) 2020-30
Total Dwelling annual average growth of 0.4% (17 dwellings annually) 2020-2030 (Source: Waimate District Council Growth Projections 2021)

Climate Change

Our Assumption: We assume that during the AMP planning period the South Canterbury region will experience the impacts of climate change through increased average annual temperatures, decreased average annual rainfall, increased likelihood of significant rain events, increased high wind events, and increased coastal erosion and inundation. While there is a high level of uncertainty around the timing and extent of these impacts, we acknowledge the increased risk to our network because of climate change related weather events and temperature increases.

Our Response: Due to the uncertainty surrounding climate change related risks to our business and network, we will conduct a risk assessment during this planning period to support future planning and risk mitigation.

Our Assumption: We assume that national and international efforts to minimise climate change impacts will lead to increasing emissions reduction and decarbonisation action from central and local government, businesses, and consumers.

Our Response: Enabling electrification across South Canterbury and reducing our own emissions are strategic priorities for our business and network planning.

Natural Hazards

Our Assumption: We recognise the risk to our network from high wind events, significant flood events, wildfire, significant snow events, tsunami, and earthquakes.

The increasingly magnified effects of climate change and the more frequent occurrence of natural hazard events across New Zealand means it is prudent to assume that our assets and our business will be negatively impacted by natural hazards during this AMP period.

Our Response: Our design standards ensure that appropriate materials are used to minimise network risk from natural hazards, particularly wind, snow, and earthquake hazards. We will continue to monitor weather patterns and predictions to ensure our design standards are appropriate to minimise risk.

COVID Pandemic

Our Assumption: The COVID pandemic has had a significant impact on our business and growth and development within our service area. As an essential service, we will continue to operate and respond as necessary. We have well established processes to respond to any changing public health policies during the AMP period.

We assume the financial impacts of the COVID pandemic will continue to have an impact on our business in the early years of the AMP period.

Our Response: The ongoing financial impact of Covid-19, especially on the cost and delivery times of materials, access to skilled labour and resulting inflationary pressures have been included in our budget process and service delivery processes.

Electrification

Our Assumption: We acknowledge that electrification has a central role in reducing emissions locally and nationally to meet New Zealand's emissions reduction targets and zero carbon goals.

We assume that the bipartisan support for New Zealand's emissions reduction targets, international market forces, and customer appetites, will ensure that electrification continues irrespective of the central government election in October 2023.

Our Response: This AMP, and future AMPs will provide the basis for our plans to deliver immediate and longer-term network development to support regional electrification and deliver customer-initiated work.

Distributed Generation

Our Assumption: While we continue to see an increase in enquiries and applications for the installation of medium-large scale PV units, we assume that this will not significantly affect peak load growth during this planning period due our industrial and commercial load profile.

DER and energy storage will support future network capacity issues. Uncertainty remains around the timing of the energy storage.

Our Response: Our network development plans and resulting 10-year budget has been prepared based on this assumption. However, we recognise that a step change may occur during this planning period and will therefore continue to closely monitor enquiries and DG developments across New Zealand and in South Canterbury.

Our planning continues to include network and non-network solutions to capacity issues.

Open-access Network

Our Assumption: We assume that distribution networks globally and nationally will commence the transition to an open-access network. We expect to see an increase in customer demand for this, supported by regulatory change. The shift to open-access networks will require deeper insight of the LV feeders on our networks, new analytical and operational capabilities, and commercial arrangements.

Our Response: We will continue to monitor developments and explore opportunities to support any future transition on our network.

Technology and Digital

Our Assumption: We assume that during the AMP planning period new technologies implemented across our business and network will enable us to better manage and forecast load demand. Upgraded information and data management systems will also enhance our ability to plan and maintain safe, reliable, and resilient network for our customers.

We also assume that the uptake of new technologies by our industrial, commercial, and residential customers will have an impact on our load demand.

We assume that across our business we will increase our reliance on digital solutions to deliver efficient services and that cybersecurity threats will remain at a level where current investment forecasts are sufficient to manage this risk appropriately.

Our Response: Our non-network and business support planning during this AMP period will have a strategic priority of ensuring that data and technology is at the heart of our business to achieve greater operational efficiency and responsiveness.

Customer Expectations of Network Performance

Our Assumption: Based on consistent data collected in our annual Customer Satisfaction surveys, we assume that our residential and commercial customers want us to maintain current performance levels (also considering price impacts).

Our Response: Our network investment across this planning period is developed on the assumption that we will maintain our current performance during this AMP period.

Asset Lifecycle Management

Our Assumption: We assume no significant sale of network assets during this AMP planning period and that we will continue to use a condition and risk-based approach to asset maintenance, renewal and replacement.

We assume no significant change to standards, consents, or regulatory obligation other than those detailed in this section.

Our Response: Our maintenance, replacement and renewals budgets have been prepared in line with this assumption. We will continue to explore opportunities to utilise data and technology to refine our maintenance planning and delivery.

Service Delivery Arrangements

Our Assumption: We will continue to use NETcon Limited as our main contractor for the construction and maintenance services to most of our network through a master services agreement for this AMP planning period. These services are based on independent industry verified rate cards to ensure efficient expenditure. Where rate cards are not possible for complex and varied work scopes, we will go to the market to obtain the most cost-effective solution.

For new connection projects, our customers can obtain the services of any network approved contractor.

Our Response: To ensure our service delivery arrangements remain high-quality and cost effective for our network and our customers, we will engage closely with, and continue to monitor the performance of all contractors who work on our network.

Inflation

Our Assumption: Our AMP cost forecasts are stated in constant prices in FY23 terms. For some of our regulatory disclosures in Appendix D – the Report on Forecast Capital Expenditure (Schedule 11a) and the Report on Forecast Operational Expenditure (Schedule 11b) – we allow for price inflation and forecast in nominal dollars in certain components of the schedules.

We base our inflation assumptions on forecast information provided by ANZ and RBNZ. We generally apply a labour cost index (LCI) to the estimated labour component of CAPEX and OPEX, and a producer price index (PPI) to the other components of our capital expenditure and operational expenditure.

Our Response: We adjust the CPI forecast provided by ANZ and RBNZ to reflect a CPI that is a combination of both views to have a balanced approach. Our local view of wage and salary increases is linked to CPI. This affects nominal information contained within the system operations and network support and business support forecasts contained in Appendix D, Schedule 11b.

Revenue

Our Assumption: Each year we set prices in a manner that ensures that we comply with the DPP set by the Commerce Commission while earning sufficient revenue to fund the continued enhancement of the reliability and security of our network.

Under the Commerce Commission's DPP3 Determination, our maximum allowable revenue is capped, and our lines charges will be managed annually to comply with this cap. We assume that under future DPPs we will continue to have a revenue cap, with an increased WACC and this is factored into our revenue budgets. We note that the uncertainty around our DPP4 revenue is significant.

Our Response: We are mindful of the impact price increases have on households and businesses and our obligation to balance cost increases against the need to provide a resilient network for our growing communities.

Governance

Our Assumption: We assume that our existing governance and ownership structure will continue for this AMP period.

Our Response: Through our formal governance processes, and close engagement with our shareholders, we will continue to deliver on our Board and shareholder's expectations.

Supply Chain Uncertainty

Our Assumption: Over the last 12 months we have observed high levels of volatility on the supply side of network maintenance and capital delivery (construction). Supplier lead times and costs for network equipment have increased significantly due to disruption to international and domestic freight routes, resource constraints and a surge in demand from consumer goods manufacturers competing for raw materials needed by the electricity sector. We assume that climate-change and pandemic related disruptions will continue to disrupt our supply chains over the next 10 years. We assume that, as the world economy continues to recover from the impacts of Covid-19, we will continue to experience long lead times and increased costs for materials.

Our Response: We employ active management of our works programme to accommodate for extended lead times, resource constraints and higher delivery costs. We revise the programme based on delivery commitments from our suppliers and contractors, while considering the risks associated with each project and defer some projects based on available funding.

04. Customer and stakeholder experience

Customer and stakeholder experience

Our vision is Empowering Our Community.

To do so we are committed to being closely connected to the customers we serve, and the stakeholders we work with. Our customers' needs and expectations are changing, and we must adapt our approach to reflect their voice in our planning, service delivery, and decision-making. By considering a variety of stakeholders' needs and interests, we can identify pain points, add value, and ensure our customers receive the best possible service.

This section outlines how we identify and engage with our customers and stakeholders to understand their needs and sets out our plans to improve their experiences. We also outline our customer connections practices, and our outage notification processes.

Overview

As previous sections of our AMP have highlighted, we are facing significant changes across all elements of our business. Our customers' needs, and expectations of our services are changing, as are the ways they want to engage with us. We must adapt our approach and ensure that our customers' voice is reflected in our planning, our service delivery, and our decision-making.

Macro drivers like climate change and zero-carbon, digital transformation, demographic change, and inflation are impacting almost every industry, every business, and every household across our community. As a result, people are changing the ways they work and live.

Whether it is one large industrial customer changing from coal to electricity for process heat production to meet their zero carbon targets, a commercial business electrifying their vehicle fleet and installing EV charges to reduce fuel costs, or a significant number of residential customers now working from home during the day – the business and lifestyle choices of our customers can have a significant impact on our business and our network.

So we need to think differently, not just about how we deliver electricity, but how we engage.

It also means we need to get to know our customers better, understand what their pain points are, map out how we can improve their experiences and add value to their day, defining how our decision-making can better reflect their voices in our business.

Strategic Pillar – Customer Experience

Our strategic pillar of "Customer experience" will ensure that we always put our customers first. To build this pillar, we will:

- Appoint a General Manager Customer, to elevate the importance of our customer voice in our business
- Develop our engagement programme to capture the voice of our customers in our decision-making, including:
  - Engaging regularly with larger energy users and key stakeholders on an individual basis
  - Expanding our annual survey to cover a more representative sample of the community
  - Facilitating energy forums with key stakeholders

Quality customer and stakeholder engagement drives better outcomes for our business, and can result in efficiencies, cost saving and improved community awareness of our role, whilst electricity safety and energy efficiency can help reduce disruption to businesses and residents.

Our aim is to move from reacting to customers' electricity needs, to understanding and anticipating their needs; from communicating with stakeholders, to collaborating as standard practice.

Identifying our stakeholders and their interests

Our stakeholders and their interests are summarised in Figure 1.

Figure 1: Stakeholder interests.

Resolving conflicting interests

Feedback from customers and stakeholders consistently identifies that the provision of reliable, safe, and affordable electricity supply, excellent customer service, and timely and accurate communication is of primary importance. But, as Figure 1 shows, our stakeholders have diverse interests and there are times when we need to manage conflicting stakeholders' interests in our asset management planning and service delivery to deliver the best outcome.

We accommodate stakeholder interests and manage conflicts that arise by:

- Putting safety of our people and our community first always
- Aligning our asset management planning and service delivery with our vision, values, and strategic direction
- Having due consideration for the affordability of our services
- Complying with regulatory and legal obligations
- Using risk management strategies
- Striving to provide a range of options for customers' energy needs
- Engaging regularly with different stakeholders
- Clearly communicating our own position, including risks, challenges, and opportunities

In developing solutions where conflicting interests exists, we aways strive for consistency, transparency, and fairness in our decision-making.

How we engage

To ensure we provide the best possible service, we utilise a range of engagement tools and offer multiple avenues for customers and stakeholders to connect with us, access information, and provide feedback in a way that suits them best.

Our engagement practices and channels include:

Website

Our website hosts a range of information for customers and stakeholders including information and our policies and processes relating to:

- Customer connections
- Distributed generation
- Vegetation management
- Managing outages
- Pricing
- Safety
- Cable location and plans
- Regulatory disclosures
- Corporate documents

All planned, and notified unplanned outages are published on our website.

We are updating our website, with the aim of updating the content, refreshing the websites look and feel and improving our online services to better communicate our business and help deliver our services.

Call centre

Our call centre is available 24/7, and we make it a priority to resolve customer issues as quickly as possible. Timely and efficient service is crucial for our customers, and we strive to provide an experience that exceeds their expectations.

Our call centre is a crucial support for our business operations, particularly during power outages, and emergencies.

Media, advertising, community events and sponsorship

Media releases, social media channels, community events, and sponsorship are used to promote public safety messages, provide information on outages and significant projects, promote energy efficiency initiatives, and encourage feedback from customers and the community. These include:

- Media releases for significant business activities
- Facebook posts providing real-time outage information
- Radio and social media promotions for public safety and vegetation management
- Displays at community events including Agricultural and Pastoral Shows regarding farm safety around electricity
- Sponsorships and partnerships that enable us to engage with our community on electricity matters

Surveys

We undertake an annual customer satisfaction survey, carried out by independent researchers to measure levels of satisfaction with our overall service, network reliability, communications, value for money and a range of matters of customer importance.

The survey breaks respondents down according to GXP, and general location (urban or rural), and customer type (residential or commercial). This enables us to identify satisfaction trends in a more targeted way and respond appropriately through our asset management planning, service delivery, and engagement tools.

Key personnel relationships

As a smaller EDB, operating in rural and provincial districts, relationship building is central to our ability to deliver quality customer services. Our Customer Services Team has strong relationships with key stakeholders, including developers, local authorities and utilities providers, and commercial and industrial customers.

Other teams across the business also have well established relationships with key personnel within Transpower, regulators, community groups, and retailers that support the delivery of services and effective collaboration.

Workshops and working groups

We hold regular workshops with our shareholders and other stakeholders. These provide face to face opportunities to communicate our plans and seek feedback.

As a smaller EDB, collaboration with our stakeholders, other EDBs and industry participants is essential. We are actively involved in several industry and local working groups. This engagement provides us with opportunities to contribute to the decisions that impact our business and to gain valuable insight into our stakeholders' plans and interests.

Timaru CityTown Project: Collaboration with Timaru District Council

Timaru District Council have committed over $30 million to the regeneration of the Timaru town centre over the next 10 years. Council is also planning significant investment in renewals and upgrades of the CBD water and sewerage infrastructure during this time. We are part of the CityTown working group to ensure that we can support Council and community development aspirations. Central to this collaboration are plans to align our future CBD work programmes with Council's to reduce the impact to businesses, residents, and visitors to the CBD, and to reduce overall costs.

Major project engagement

Where major projects have a significant impact on the community, we provide enhanced levels of communication with our customers and key community stakeholders, especially directly impacted businesses and households.

Through media releases and other advertising channels we also provide information about major projects to the wider public. This can include public notices detailing timelines, benefits and impacts on customers and the community. We are also increasing our outreach on these projects through school visits, local advertising, and social media campaigns.

Measures and targets

This AMP period marks a strategic change in our approach to customer services and stakeholder engagement. We are developing a comprehensive customer and stakeholder engagement programme. This programme will include corresponding measures and targets to track our success and ensure we are delivering on our strategic pillar of Customer Experience.

One of the tools this programme will leverage is our customer satisfaction survey. During the next two years we will be expanding our survey approach to make sure we cover a more representative sample of our community and that we address the issues of greatest interest and concern to our customers. This will enable us to establish further customer satisfaction targets and engagement plans across a range of customer categories. We will look to develop other customer tools to provide real-time feedback on issues most affecting customers.

Our customers' voice

What our customers have told us

Our customer satisfaction surveys offer key insights into customer views of our services, areas of improvement and customer trends.

In October 2022, Key Research surveyed 342 of our customers across all seven GXPs to assess perceptions of reliability, outages and notifications, pricing, and uptake of new technologies and EVs.

The survey revealed that areas with the largest proportion of satisfied customers included:

- Delivering a safe power supply (83% satisfied)
- Providing a reliable power supply (81% satisfied)
- The attitude of staff (78% satisfied)
- How helpful staff are (77% satisfied)
- Minimising the number of outages (75%)

This reflects well on our ongoing efforts to maintain a safe and reliable network and our priority of putting customers first through quality customer service across the business.

Areas with the largest proportion of dissatisfied customers included:

- How well we communicate about the things we are doing (20% dissatisfied)
- How we deal with customer issues in a timely manner (19% dissatisfied)
- Lines charges are good value (18% dissatisfied)
- How well we keep customers informed about power supply matters (18% dissatisfied)
- How well we communicate about keeping safe around electricity (17% dissatisfied)

These responses reinforce what we know about increasing customer expectations for real-time information about network outages and planned work, as well as greater expectations for more proactive communications across all business activities.

The survey also revealed that our customers have little willingness for increased lines charges to improve the reliability of service provided; with 80% preferring to maintain current levels instead of increasing or reducing prices with associated changes to service. This result is consistent with our previous survey responses and is an important input when determining the level of network investment into reliability associated projects and required pricing structures to support this.

Our latest survey reveals that 50% of customers surveyed are likely to purchase an EV within the next 5 years (6% 1-2 years, 44% 2-5 years). Just 8% of respondents indicated they were never likely to purchase an EV. This is a significant change from our previous survey (2020) where nearly 50% indicated they would never purchase an EV, and less than 10% indicated they would purchase an EV within the next 5 years.

This change correlates with our analysis of the anticipated increased EV uptake across South Canterbury. We will continue to monitor EV uptakes locally and nationally and will undertake modelling of the impact of residential EV charging on the LV network.

In 2022/23 we also conducted a materiality assessment with our key stakeholders to identify and prioritise material issues for us. This assessment was undertaken to support the development of our Sustainability Strategy, but the insights will also be considered in our asset management planning in the future. The issues of greatest importance to stakeholders were:

- Customer satisfaction
- Stakeholder engagement
- Employee wellbeing, safety, and engagement
- Supporting renewable energy options
- Good supply chain management
- Preparing for the impacts of climate change
- Recruitment and retention of talent
- Business transparency and authenticity
- Environmental protection from waste and hazardous materials

How we plan to respond

We are conscious that capturing feedback from our customers and stakeholders is only one step in the engagement process. We need to consider this feedback as part of our planning and decision-making processes and turn listening into action.

Feedback	Our plans to respond
Customer Service	
Excellent customer service across the whole business is a priority for our customers and stakeholders	**Engagement programme:** To ensure we are delivering on our commitment to put our customers first we are developing a customer engagement programme. **Technology solutions:** We are exploring opportunities to improve our customer services including implementing a Customer Relationship Management system (CRM).
Health and Safety	
Customers and stakeholders want us to prioritise delivering safe electricity and to continue providing safety education	**Safety roadmap:** We have developed a robust safety roadmap covering all aspects of our business and network. This will be implemented in 2023/24. **Safety education campaigns:** We will continue to provide safety education through media campaigns and engagement with local schools and community groups.
Our work plans	
Customers aren't as well informed about our work plans and our business as they would like to be	**Engagement Strategy:** Communicating our asset management plans effectively will form an essential part of our customer and stakeholder strategy. **AMP on a page:** We have developed a clear and concise overview of this AMP to help us communicate our plans more effectively with stakeholders and customers
Preparing for the future	
Customers and stakeholders want to know that we are prepared for future energy challenges	**Energy Strategy:** The development of this strategy in 2023/24 will help us plan and respond to the future uncertainties within our sector. **Low voltage monitoring:** Utilising data and technology we will increase our monitoring of our LV network to ensure our customers' energy preferences are supported. **Stakeholder collaboration:** We continue to engage closely with our key stakeholders to ensure our plans are informed by their interests and we are responding to their needs. **Strategic direction:** Our long-term strategic plan is future focused and takes into account our changing industry and our customers' needs
Sustainability	
Being a sustainable business, and supporting the community to decarbonise is increasingly important to our customers and stakeholders	**Sustainability Strategy:** We will implement our Sustainability Strategy during this planning period. **Energy Strategy:** This strategy will ensure we are well placed to support our customers' decarbonisation plans and provide sustainable energy options for our communities.

Customer connection practices

Planning and managing new customer connections and alterations is critically important to our asset management process, in meeting the expectations of customers, and delivering on our aim of empowering our community.

Our Customer Services team is central to delivering this work, and our customer services protocols are built around principles of relationship building and open communication between our team and our customers. This team manages engagement with customers for new or altered connections enquiries, and power quality issues. They are supported by other teams across the business to ensure that we meet customers' new connections and alterations expectations.

Our approach to planning and managing new customer connections and alterations is as follows:

Step	Customer practice	Engagement
Step 1: High level feasibility	Project lead established for each new connection or alteration. High level feasibility and job scoping with customer.	Customer Services Project Leads undertake an onsite visit with customer and their electrician to review the initial expectations and requirements of the job.
Step 2: Inhouse design	Our inhouse design for new connections and alterations is managed by our Customer Services, Planning, Drawing Office, and Engineering Teams.	Ongoing engagement with customer relating to any network constraint issues and design options arising during this process to ensure timely resolution of any issues arising.
Step 3: Confirmation with customer	Once design is completed, customers are provided with design and contract pack including quotes from contractors.	Customers contacted personally and receive design and quote confirmation via email or post.
Step 4: Delivery	Upon customer confirmation of quote and contractor selection, the contractor is responsible for the delivery of work.	Customer services project lead maintains ongoing engagement and undertakes issues resolution until project completion. This includes engaging with contractors and other parties involved as required.

For large customer connections or alterations (industrial or large residential and commercial developments), we establish an internal project team to manage the delivery of customer work and network upgrade requirements associated with the work. Project teams also develop clear customer and community engagement plans to support the success of these projects.

We continually seek opportunities to minimise cost and delays to customer connection work. Regular and open engagement with customers and contractors is central to this.

Other efficiency practices include:

- On-site job scoping and feasibility meeting with customer and electrician to identify all project risks from both the customer and network perspective
- Engaging closely with other utilities providers and civil contractors to combine works where possible
- Where possible providing multiple contractor quotes to ensure competitive pricing offered to customers
- Continuous improvement of internal systems and processes to minimise time and cost to customers
- Regular internal network development and works programme planning workshops to ensure asset management and service delivery functions are well informed of customer-initiated work and network constraints

Where possible we seek to mitigate commonly encountered delays:

Commonly encountered delays	Our response
Contractor availability	We work closely with local contractors to support capability and capacity development.
Supply chain shortages	Where possible we bulk purchase common materials, and engage with other EDBs to access materials.
Consenting delays with local councils	We have well established relationships with local councils and support customers to understand consent requirements were necessary. For large customer initiated work we undertake early engagement with councils to identify any potential consent requirements for the customer and any network upgrades required.
Transmission GXP upgrade requirements	Although this isn't a commonly encountered delay, we anticipate future large-scale customer-initiated work that will require transmission GXP upgrades which could extend project timelines considerably. We engage closely with Transpower to ensure required upgrades are delivered in a timely manner.

Customer Connections Value Chain Optimisation

As part of our 2022 review into our core operations value chain we identified two key initiatives to improve our internal customer connections processes, and ultimately deliver exceptional end-to-end customer service.

- Implementation of a Customer Relationship Management (CRM) system to track new customer network demands, ensuring that they are delivered on time, and providing intelligence about customer connection growth for network planning purposes.
- Implementation of a customer connection workflow to simplify new connections processes and to allow increased self-service by customers seeking new connections.

Timeframes

Quality project management, risk identification and mitigation and transparent engagement with customers and contractor are central to our efforts to deliver customer work within expected timeframes. However, circumstances beyond our control can lead to delays.

Indicative time frames for customer work:

- **6 - 12 months** for a connection requiring a network line or cable to customer site
- **18 - 24 months** for a connection requiring a substation transformer upgrade
- **24 - 36 months** for a connection requiring an upgrade to switchboards or to construct substation housing
- **12 - 24 months** for a connection requiring an upgrade to a circuit connecting a substation to a Transpower substation
- **2 - 4 years** for a connection requiring an upgrade to a Transpower GXP

Other Customer Services practices

Service Delivery Team is responsible for the management and the delivery of capital projects and maintenance schedules, engaging with customers and the wider community on issues including vegetation management, property access, and project management for significant customer-initiated projects. Working closely with our Communications and Marketing Team, they also engage in targeted communications for specific projects where businesses and households may experience disruption due to network activity.

Operations Team is responsible for managing outage related notifications with customers and the wider community through our notification online outage tool and other engagement channels. This team also engages with customers seeking close approach permits for our network assets.

Asset Information Team manages customer enquiries relating to the location of our asset.

Notice of planned and unplanned interruptions

Delivering secure, reliable, and sustainable electricity to all our customers is our priority. However, due to various reasons, such as natural disasters, equipment failures, and maintenance activities, power outages may occur.

Considering this, we recognise the impact that power outages have on our customers and their businesses. Therefore, our corporate intent is to provide timely, accurate, and transparent information about any power outages that may affect our customers.

We pride ourselves on providing reliable electricity supply but there are times when outages are necessary for planned works, or because of unanticipated events. Our customers have also told us how they would like us to communicate with them about planned outages, and when. Prompt notifications of unexpected outages and restoration times are also valued.

Planned outages

We notify all planned outages on our website, and directly contact affected customers by email, post or in person, where necessary. Where works will result in a significant outage (as defined by the number of people affected and/or duration), we publish outage details in the newspaper, on social media and use radio advertising to ensure greater reach.

We aim to continuously improve notified outage communications and will work with stakeholders, including the retailers as to how we can better communicate with our customers.

Unplanned outages

To ensure prompt communication, our automated fault system updates as soon as faults are identified. This generates a voice message for customers calling our call centre and updates the outage map on our website. We also post public updates through our social media platform.

Customer complaints

Our Communications and Marketing team manages our customer complaint resolution process. They are supported by an internal complaints team to ensure our response is appropriate, impartial, and informed by subject matter experts.

We aim to respond to all complaints within 24 hours, and achieve resolution within seven days, however this is dependent on the complexity of the complaint.

Our preferred approach to complaint resolution is through direct engagement with the customer. We are also a member of the Utilities Disputes complaints scheme and widely promote this scheme to customers.

05. Asset management overview

Asset management overview

Ensuring safe, reliable electricity supply which meets the needs of our community, while adapting to our changing environment requires effective asset management systems and processes. Strong asset management planning and systems will enable us to innovate and shape what the future of our business will look like. Our asset management capability builds in response to the key changes in our environment and in support of our strategic pillars.

This section provides insight into our asset management framework and practices. To highlight continuous improvement initiatives, an overview of our asset management maturity is also included, along with identified areas of ongoing development.

Links to our strategy

Our asset management planning is a critical component in aligning the management of our assets with our strategy, enabling us to maximise their value in achieving our goals. By focusing on well-designed asset management planning, which takes into account current and future needs of our customers and our business as well as the resources needed, we establish clear goals and priorities in managing our assets. This planning is vital in facilitating our strategy of delivering secure, reliable, and sustainable electricity, which enables our customers and communities to make informed energy choices. Our asset management planning supports the strategic pillars of building a network for the future and operations that ensure we keep our customers connected. Through our planning approach, we can align the management of our assets with our strategy, ensuring that we deliver on our commitment to meet the energy needs of our customers and communities in a sustainable and responsible manner.

Asset Management Framework

Our Asset Management Framework (AMF) supports effective asset management planning in line with best practice, including International Standards ISO 55000, ISO 55001 and ISO 55002. It details the various levels at which asset management activities are performed to give a clear line-of-sight in how all activities contribute to achieving the overall company objectives. To effectively and accurately set course, it is important to have a clear vision of where we want to be. This is illustrated in the AMF depicted in Figure 1 and represents a suite of documents that describe how we manage our assets throughout their lifecycle.

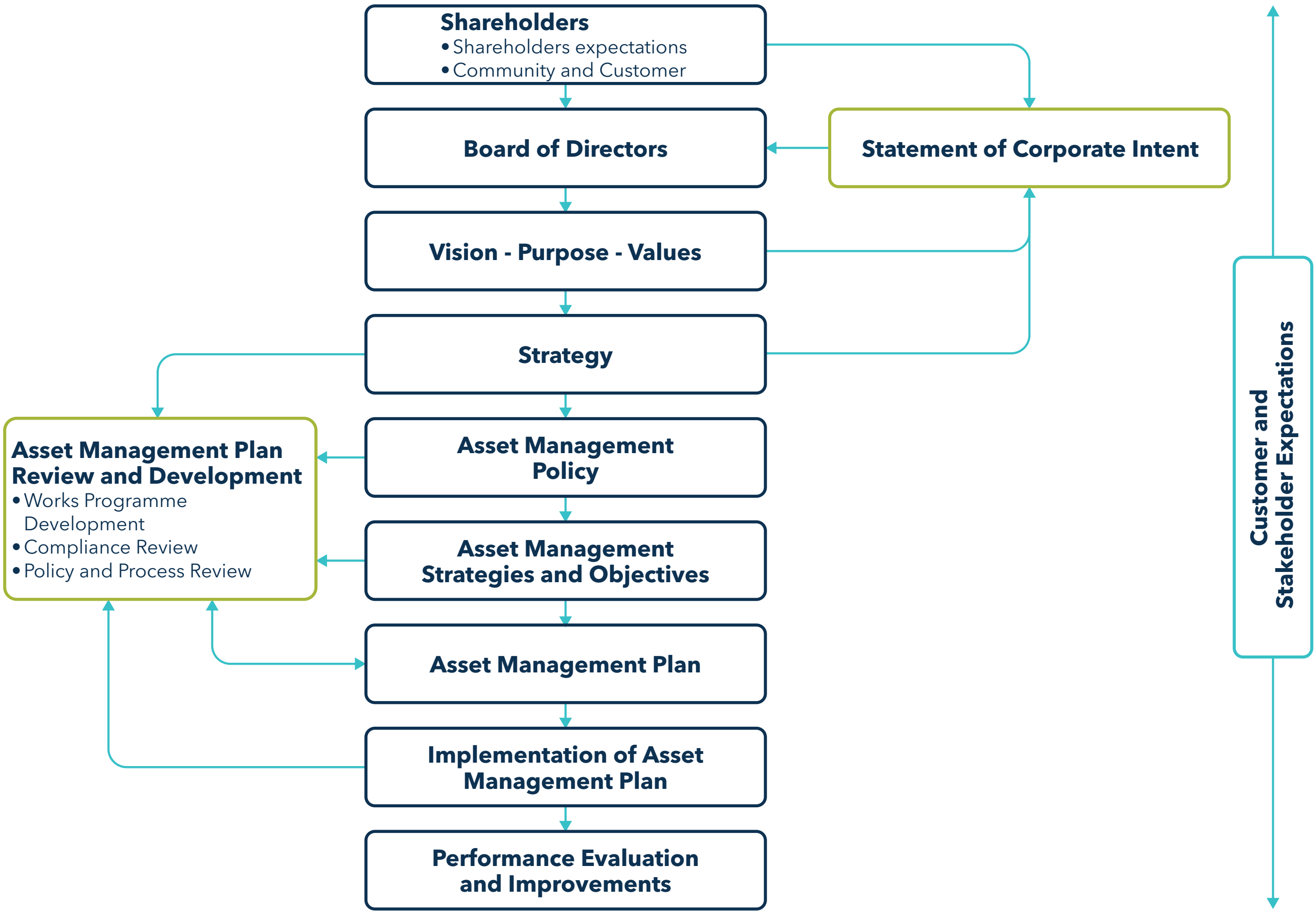


Figure 1: Asset Management Framework.

Asset Management Policy

Our Asset Management Policy aims to align our service-orientated asset management activities with our values and strategy.

Our policy confirms our commitment for ensuring that our distribution network is planned, designed, constructed, operated and maintained to provide a safe, reliable and efficient electricity delivery service. We demonstrate our commitment by:

- Always putting **safety** first in all asset management activities and striving for 'zero harm' to employees, contractors and members of the public
- Engaging with our **community and stakeholders** to improve relationships through all asset-related activities that affect them
- **Complying** with all applicable laws, legislation, regulations and codes of practice in the execution of all asset management related activities
- Providing a reliable and efficient distribution network to meet our customer expectations including environmental responsibility and sustainability, while supporting New Zealand's **climate change** objectives through the **decarbonisation** of the economy
- Focusing on our **network performance** and managing our assets to achieve our desired service levels.
- Evaluating the **costs and risks** in delivering expected performance and maximised asset value
- Ensuring that asset management decisions for investment, maintenance, operational expenditure, and replacement are made on all accurate and timely **information**, and in accordance with the delegated authority

- Considering how we build capability to use non-network solutions and demand management to optimise our investment decisions. Ensuring our organisational structure and staff represents the correct mix of people and **skills** to develop and improve our asset management capability to deliver our asset management objectives
- Continually developing our asset management **systems** to turn data into informed decision-making that will optimise our asset value.

Asset Management Objectives

In line with our vision and strategic pillars these policy statements are translated into asset management objectives which consider our operating context and respond to specific stakeholder requirements.

Our Asset Management objectives are:

- A safe electricity delivery service as described in our Statement of Corporate Intent and with health and safety always as our first company value, it is appropriate that health and **safety** is the first objective in managing our assets
- **Service levels** and our performance against them are key indicators of whether we have met or exceeded our customers' expectations. In this regard, we want to improve or maintain levels of security, reliability, and resilience that are acceptable and affordable to our customers and satisfy the regulatory quality standard. To achieve this, we need to assess the resilience of our network to climate change impacts and ensure that it is able to withstand extreme weather events
- To meet our stakeholders' expectations and support our company mission it is important to manage **cost** and deliver performance through efficiencies and staying within our capital and operational expenditure budgets
- As an asset management company, we exist to enable economic growth by providing electricity delivery and infrastructure services. Managing our assets also means that we will **engage** with the South Canterbury **community** to establish, maintain and operate our assets
- To manage our assets in a socially responsible and sustainable manner, we will integrate Environmental, Social, and Governance (**ESG**) factors into our decision-making processes and asset management practices to promote the long-term health and well-being of our communities and the environment. We will do so within the context of **reducing our carbon footprint**, enabling **distributed generation** initiatives that require a connection to our network, and support customers and stakeholders in their **decarbonisation** initiatives
- Recognising that we are on a journey towards better alignment with ISO 55000 and improving our Asset Management Maturity Assessment Tool (AMMAT) scores as reported to the Commerce Commission, we must continually improve our asset management **capability** to achieve strategic objectives

Asset Management Plans

Our AMP plays a crucial role in ensuring the safe and reliable delivery of electricity that caters to the community's needs and adapts to a rapidly changing environment. Effective asset management systems and processes are fundamental to achieving this goal, and our AMP is developed to support these systems.

Our AMP serves as a roadmap that guides the future development of our asset management by combining the needs of our customers, network capacity planning, and asset lifecycle management. Our AMP is informed by our Asset Management Policy, Framework, Objectives, and Fleet strategies to provide a clear line-of-sight on how all activities contribute to achieving the overall company objectives.

Our commitment to a safe, reliable, and efficient energy delivery service is reaffirmed through the AMP, which outlines the principles that guide our asset management activities. Additionally, the AMP supports our Asset Management Objectives by taking into account the operating context of our assets and addressing specific stakeholder requirements. Safety, service levels, cost management, community engagement, and continuous improvement are Asset Management Objectives that form key focus areas in our AMP.

Asset management supporting processes

There are a number of standards and supporting processes in our asset management system. We are aligning our asset management system with the requirements of ISO 55001 and developing and improving our supporting infrastructure to do so.

Figure 2: Asset Management Hierarchy.

Policies and strategies

Our policies and strategies are listed below with a description on how these interact with our asset management process.

Document	How it impacts our asset management
Risk Management Policy	Ensure that risks are managed wisely and effectively with the aim of enhancing value, boosting performance, fostering innovation, and helping to achieve goals. Our risk policy outlines our approach to risk exposure, including the necessary administrative, human, and financial resources for risk mitigation. Risks are only accepted deliberately and within established risk tolerance levels. Our risk management policy guides our asset management by network risks and investment decisions are evaluated and managed in line with our objectives and ISO 31000:2018 Risk Management Guidelines.
Delegation of Authority Policy	This policy details the operational framework within which the Board provides sub-delegations of authority to our employees to ensure accountability and responsibility in decision-making. All decisions within our asset management system that require expenditure or involve significant risk will be made under this policy and in accordance with our delegation approval process.
Health and Safety Policy	This policy outlines our commitments and standards for health and safety. We will conduct our business in a way that safeguards the health and safety of our people, contractors, the public and visitors to our sites. This policy is central to the way we deliver our AMP, from project design through to construction and ongoing maintenance of assets.
Lifecycle Strategies	These strategies serve as a bridge, connecting our Asset Management Policy, Framework, Objectives, and Fleet strategies with our Asset Management Plan. They embody our asset life cycle approach and put into practice the overarching goals through relevant and feasible procedures and activities.
Fleet Strategies	These strategies link our Asset Management objectives to our particular asset fleets, presenting a well-considered approach to tackle any asset-related risks. The fleet strategies inform and shape the direction of our lifecycle strategies.

Standards

Our standards are an important input into Asset Management Framework and are broadly applied in the management of our assets. It is a developing area for us while we continue to grow our asset management maturity to align with ISO 55000. The table below lists the major standards that support asset lifecycle process.

Document	How it impacts our asset management
Planning Standards	Provide a consistent and standardised approach to the planning, design, and maintenance of the electrical distribution assets, helping to ensure that the assets are operated in a safe, reliable, and efficient manner within it's design capacity. Also align our asset management activities with overall company objectives.
Maintenance Standards	Provide guidelines and best practices for the maintenance of our assets, helping to ensure that the assets are maintained in a safe, reliable, and efficient manner.
Network Operating Standards	Provide guidelines and procedures for the operation of our network, helping to ensure that the network is operated in a safe, reliable, and efficient manner.
Design and Construction Standards	Provide designs and best practice guidelines for the construction of our electrical distribution assets, helping to ensure that the assets are designed and constructed in a safe, reliable, and efficient manner.
Technical Specifications	Provide detailed specifications for the works, components and materials that we require our service providers to provide in support of our assets.
AS/NZ Standards	Provide standards for the electrical industry in Australia and New Zealand, including standards for safety, quality, and performance.

Asset management sustainability framework

Of particular focus for this AMP is delivering sustainability outcomes through the asset management and our planning processes. We will increasingly apply a circular economy approach to materials, explore opportunities to reduce our carbon emissions across our network, business and supply chain, and we consider environmental impacts of all our asset management activities. In 2023/24 we will adopt our Sustainability Strategy which will confirm and advance our commitments to:

- Include sustainability principles in our infrastructure design to reduce construction waste and environmental impact
- Develop a circular economy approach to our use of materials, assessing options to reuse and recycle and minimise waste to landfill
- Consider sustainability in procurement by assessing our full supply chain to support ethical and social procurement
- Include consideration for the protection of indigenous biodiversity, especially where our network intersects with significant natural areas (SNAs) as identified by local council District Plans
- Continue to mitigate environmental and public risks associated with infrastructure, especially our use of sulphur hexafluoride gas (SF_6) and transformer oil

Our Environmental Policy currently governs our efforts to act with environmental responsibility.

Lifecyle delivery

Deliver

We strive to deliver capital investments in a safe and cost-effective manner during the delivery phase. To achieve this, we constantly challenge and improve our standards and specifications, engineering designs, project planning, project management, and construction skills. By prioritising these efforts, we can ensure that we deliver projects on time, on budget, and to the satisfaction of our stakeholders.

Operate

We operate our network to provide our customers with safe and reliable electricity. In order to maximise network availability while providing safe maintenance and construction, this involves planning and overseeing access to all our assets.

Maintain

Assets on our network are maintained to ensure they remain safe, secure and reliable. When developing our scheduled maintenance plan, decisions are taken to ensure that we effectively balance both capital and operational investment.

Dispose

When an asset is getting close to the end of its useful life, asset disposal is necessary. A number of factors might lead to disposal choices, such as poor asset conditions, changes to safety or environmental regulations, or shifting market conditions.

Asset management responsibilities

An overview of the asset management accountabilities and responsibilities is set out below.

Board and Executive Leadership Team

Board of Directors

At the highest level, our Board of Directors (the Board) operates under the Board Charter and provides governance over all aspects of our asset management practices on behalf of our owners and the broader stakeholder community. The Board exercises oversight of our strategic direction, the objectives of asset management, investment decisions and the customer service levels achieved by our network. Overall budgets, significant expenditures and asset investments are reviewed and approved at a board level.

The Board maintains its asset management oversight through the implementation of governing policy, a delegated authority framework, management reporting and periodic internal and external audits.

Chief Executive Officer

Under the delegated authority framework, the approved strategic plan, approved annual budgets, and day-to-day operation of the business is the responsibility of the Chief Executive Officer (CEO). The CEO maintains oversight of our asset management practices, including effective risk management (both strategic and operational) service level outcomes, implementation of strategic direction and investment decisions.

Executive Leadership Team

The CEO is supported by an Executive Leadership Team (ELT) who are responsible for their budgets and operating within their delegated authorities. With the CEO, the ELT are accountable for the delivery of asset management plans and provide the Board with regular progress reports on the works programme and significant projects.

Management team

Works Programme Committee

A Works Programme Committee (WPC), made up of senior managers and senior technical experts is an internal committee responsible for the development of the draft works programme. This committee identifies network needs, assesses options, and prioritises network investment using our risk framework. The WPC recommends the draft works programme to ELT for consideration as part of the AMP development process.

Assets and Operations

Our Assets and Operations business units cover the teams managing our network. Collectively these teams are responsible for:

- The overall direction and management of our network infrastructure
- Asset management through future network investment decisions
- The daily operation of the network
- The delivery of the AMP work programme
- Providing engineering related services
- Enabling customer connections
- Maintaining and replacing our existing network
- Providing asset information management

There are seven teams who share responsibility for the long term management of our assets:

Planning: Responsible for the strategic planning of the network required to meet security of supply (SoS) requirements, growth, and other demands.

Asset Lifecycle: Responsible for the management of network assets over their life through the preparation and implementation of maintenance schedules, collection and response to asset condition data and our asset replacement programme.

Engineering and Standards: Responsible for the design and technical support to projects and leads the development of our design standards.

Asset Information: Responsible for managing and maintaining network information in our Geographic Information System (GIS) and drawing management systems.

Customer Services: Responsible for the management of all new connection and alteration applications, including DG.

Network Programme and Delivery: Responsible for the delivery of the network works programme, maintenance schedules, vegetation programme, and manages our procurement function.

Operations: Responsible for the real-time operational management of the network, providing safe network switching and fault restoration and load management.

See Section 9 for an overview of business support functions.

Service providers

We engage contractors to construct and maintain our network. Our service providers do not have direct network management responsibilities for our services. Service providers are engaged for specific scopes of work or for contracts over specific periods to deliver on our AMP objectives and works programmes.

Service providers become responsible and accountable for the requirements of the base contract, and the specific conditions attached to projects or work orders.

NETcon Limited is our main service provider and carry out the majority of the construction and maintenance services on our network through a Master Services Agreement which is reviewed regularly.

Information systems

We employ a range of core systems and tools to facilitate our asset management and service delivery.

Enterprise Resource Planning

Since 2017, we have been using the TechnologyOne (T1) Enterprise Resource Planning (ERP) solution for our asset management and finance processes. The Enterprise Asset Management module (EAM) contains the bulk of our asset data with respect to type, age, model, number, and various other generic and asset-specific attributes. T1 is also linked to our GIS application suite. Condition data and maintenance schedules for various asset types are also housed in T1.

We use T1 to keep track of work-related information for each asset. T1 keeps records of all work ordered for each asset, the expenditure on each asset, the invoicing related to the asset, the specifications of each task, the results obtained during asset maintenance work, the defects (issues or faults) reported against each asset and the photos related to these defects.

Geographic Information System

Our bespoke GIS was replaced in 2017 with Esri's ArcGIS and Schneider ArcFM applications, modules and extensions.

Integration between our GIS system (ESRI ArcGIS and Schneider ArcFM) and T1 is well established via our use of FME as an integration layer but will be reviewed over the coming year as we look to reduce our on-premises technical debt. Our future state architecture and decisions around which integrations are retained, migrated or redesigned will also be considered in relation to our roadmap towards an Advanced Distribution Management System (ADMS).

Supervisory Control and Data Acquisition

Our supervisory control and data acquisition (SCADA) system is provided by Survalent and it is well embedded and productively used by the operations team. We are considering extending the functionality of our existing Survalent SCADA implementation such as the addition of an Outage Management System (OMS) module. An OMS will provide us with the following benefits:

- Reduced outage durations due to faster restoration based upon outage location predictions
- Reduced outage duration averages due to prioritising
- Improved customer relations by providing accurate outage and restoration information
- Ability to prioritise restoration of emergency facilities and other critical customers
- Reduced outage frequency due to use of outage statistics for making targeted reliability improvements
- Fast track down of problem location by meter ping analysis with Advanced Meter Interface (AMI) interface

Drawing management system

All drawings are stored and updated in a secure auditable manner in our drawing management system, Adept. Employees and contractors have controlled access to drawings with version control.

We also store important design standards and drawings in Adept. An internal working group are responsible for maintaining and updating these standards. Drawings, layouts and switching sheets, which are critical for the design and operation of our assets, are also stored in Adept.

Document management

We use Microsoft Teams as our primary platform for collaboration and online document sharing, with different work groups able to access and edit documents as needed. The majority of our document and information management is done via on-premises network file shares.

We store photos and drawings related to our assets which ensures that relevant information is easily accessible to our teams and assists in maintaining our assets.

Use of asset management data

We use asset management data to systematically track the lifecycle of assets within our network. This encompasses everything from the procurement of new assets to their maintenance and eventual retirement. By utilising this data, we are able to attain a comprehensive understanding of our assets, including information such as age, manufacturer, model, location and overall condition and performance.

One of the primary advantages of this data is that it enables us to identify and manage any potential risks or issues that may arise with our assets. This encompasses managing defects or issues that have been reported, as well as monitoring any open work orders or maintenance tasks that have been assigned to specific assets. Using this data, we prioritise and schedule maintenance and replacement of our assets in a timely and efficient manner.

Furthermore, our asset management data plays a vital role in guiding the growth and development of our network. We use this data to monitor our network's capacity continuously and inform our future investments and interconnection decisions. This allows us to ensure that our network can accommodate new customers and support the growth of our system.

Our use of asset management data allows us to comply with regulatory standards while improving the performance and efficiency of our assets. The data is analysed to ensure that we meet our commitments to safety, reliability and customer service, as well as identify any areas for improvement. This enables us to adhere to industry regulations, while also providing transparency and accountability to our customers and stakeholders.

Informing asset health models

We actively look for ways to increase the performance and longevity of our assets. To do this, we have created advanced condition assessment techniques to detect and repair faulty assets such as poles, distribution boxes, transformers, and ring main units (RMU) before they fail.

Our asset management data is crucial in this process because it allows us to assess the risk associated with each asset's operation. To inform our asset risk assessment, we consider additional critical aspects such as location, age, geography, and previous weather (rain, snow, sunshine, UV radiation) in addition to asset condition.

Based on the risk classification of each asset, this data is used to inform our maintenance inspection schedule. Our approach to asset lifecycle management is based on a CBARM (Condition-based Asset Risk Management) program, where we use risk to schedule condition inspections and detect asset defects. We use the findings from these inspections to inform our Markov-model-based CBARM model, plan our maintenance activities, and inform our asset health assessments. This approach enables us to be proactive in identifying and addressing potential issues before they occur, ensuring the safe, reliable, and efficient operation of our assets.

Developing CAPEX projections

We utilise condition-based inspection techniques to identify assets that require servicing and inform our CBARM model for each asset class. The CBARM models provide us with valuable insights, including the expected average lifespan of our assets. This information is used to inform our CAPEX projections and inform our long-term strategic planning and investment decisions.

By analysing the key asset condition indicators that predict asset failure, the CBARM model helps us understand the specific conditions that should be checked and the expected lifespan of an asset once a condition is identified. For example, if an oil leak is identified in a transformer, the CBARM model predicts the likelihood of future failure and the associated costs of replacement or repairs, allowing us to schedule maintenance and prioritise replacement activities in a timely and efficient manner.

Furthermore, by providing detailed information on the current and future needs of our assets, the model enables us to allocate resources effectively and ensure that we have the necessary funds to maintain and replace assets as needed, while keeping our costs and risk exposure under control.

Asset Management Maturity

Developing our asset management maturity is a key focus of continuous improvement. We review our asset management practices using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

At an overall level, our asset management maturity scores at an average of 2 out of 4 points. Our asset management maturity, compared with prior year self-assessments, is shown in Figure 3.

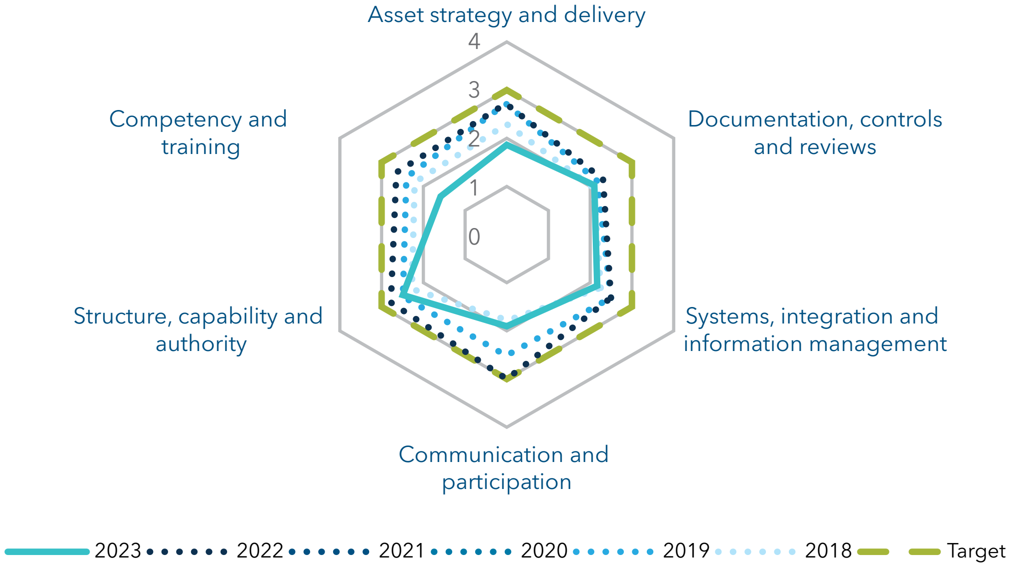


Figure 3: AMMAT Overall scoring.

This year, we have completed an independent review of our asset management maturity, this assessment rigorously tested all facets of our asset management practices and documentation. Key improvement areas that were identified were competency and training, asset strategy and delivery, communication and participation. This aligns with the commitment of our Board and leadership team to undertake a step change in how we perform as an organisation to ensure that we are best placed to meet the needs of our community and the pressure of our future environment. Our score has decreased from 2.61 to 1.97 in the last year from a self-assessment to an independent assessment. With support from external asset management specialists, we will use these reviews to address gaps and inform our plans to improve our asset management practice.

Our Asset Management improvement process is guided by our strategy. The following table outlines our plan to improve our asset management principles and business practices.

Appendix D (Schedule 13) provides details of the latest AMMAT assessment.

Initiative – Asset Management maturity

We will continue to undertake independent assessments of our AM maturity and implement an improvement plan to reach a target score of three (out of four) on each AMMAT rating criteria within the next three years.

#	Strategy	Initiative	Project Description	Priority	Period
1	Data and Technology at the heart of our business	Improve Workflow Management	Implement the findings of our workflow management review to reimagine our sequence of core business activities.	High	2022-2025
		Centralise workflow administration	Improve communication and streamline workflow with a centralised department of administrators. This will ensure efficient management and transfer of work between stakeholders.	High	2023
		Facilitate workgroups and communication through the use of Microsoft Teams	Improve communication and information storage and sharing across the organisation.	Medium	2022-2024
		Network Data strategy (Network data insights)	Establish a formal Asset Data Strategy that involves determining the data necessary for managing the lifecycle of each asset and harnesses the power of analytics to extract valuable insights from large amounts of data.	High	2022-2025
2	Customer experience	Engagement Programme	Conduct customer surveys to probe whether we are delivering on our commitment to put our customers needs first.	High	Annual
		Safety education campaigns	Provide safety education through media campaigns and engagement with local schools and community groups.	Medium	Annual
		Customer Relationship Management (CRM) system	Investigate ways to enhance our customer service through a CRM system.	High	2023-2024
3	Future Networks	LV Monitoring	Ensure our customers' energy preferences are supported by using data and technology to increase our LV network monitoring.	Medium	2025-2026
		Energy Strategy	Stage one of the strategy will develop assumptions about the extent and scale of electrification in our region. Stage two will develop a dynamic scenario planning tool to support future long-term decision-making.	High	2023-2024
4	Operations	Work Planning Committee	Review, risk assess and recommend the projects that must be included in our works programme.	High	Continuous
		Capital investment governance	Streamline the collection of field data into our databases to efficiently complete capital projects.	High	2023-2024

06. Network planning

Planning for our future network

Network planning is about providing a reliable and resilient network in the long-term interests of our customers by developing a cost-effective electricity supply to meet new and future demands and changing customer needs. Given electricity infrastructure typically has a life of more than 40 years, planning is implicitly also about understanding the long-term need for infrastructure, managing uncertainty, and avoiding stranded assets.

Today, uncertainty is higher than ever due to rapid technology innovation and changing customer preferences which also test market and regulatory settings. The majority of these uncertainties are out of our control, which means that network planning needs to be scenario based and increasingly dynamic and flexible to adjust as the future evolves, while always ensuring timely investment and delivery of network projects.

This AMP period marks the introduction of our new approach to planning with the development of an energy roadmap for South Canterbury, and a refined approach to scenario analysis.

This section describes the processes and systems we implement to identify where investment is required on our network to resolve network constraints, meet changes in electricity demand, manage changes in customer consumptions behaviour and improve climate resilience. We also detail our security of supply standards (SoSS), our approach to managing power quality, and plans for managing our LV network.

Security of Supply Standards

Security of supply (SoS) is defined as the ability of our network to meet the demand for electricity in circumstances when our network equipment fails. A key component is the level of network redundancy that enables the supply to be restored while a faulty component is repaired or replaced.

SoS comes at a cost and requires a level of investment beyond what is required to meet demand. We also ensure that load growth and any step increases do not erode any existing SoS. We have developed a SoSS (based on the Electricity Engineers' Association (EEA) Guidelines for Security of Supply) for our network, which states that on the sub-transmission system, we will strive to achieve a N-1 security level.

Our SoSS aims to meet the objectives in our Asset Management Strategy, by defining appropriate levels of SoS for different types of customer loads and establishing a basis for network development planning. It also provides guidance for decision-making on investment projects to maintain the expected level of SoS.

The objective of our SoSS is:

- To help plan efficient investments and resource allocation on the network to achieve an acceptable level of customer service and public safety
- To provide a yardstick against which interested parties can measure the appropriateness of investments made in our network

Security Level	Description
N	N is the security level at which any outage will cause load to be lost and is often found where there is only one supply circuit or transformer that provides supply. Meaning the lost load will be restored in the time it takes to repair the fault.
N-0.5	N-0.5 is the security level at which an outage will result in some load being able to be restored after ties have been made to other substations. Meaning the lost load will be partially restored (in this example 50%) after switching (reconfiguration of the network) and the remainder of the lost load will be restored in repair time.
N-1	N-1 is the security level that ensures supply after a single contingency event. Meaning no load will be lost due to a single failure.
N-2	N-2 is the security level that ensures supply after two contingency events. Meaning no load will be lost due to consecutive failures on two separate circuits.

Power quality management

There are multiple factors that affect the quality of supply to our customers. These include but are not limited to:

- Customer installations, like variable speed drives (VSDs) being connected to our network which have potential to create unacceptable levels of harmonic distortion
- Sizing of capacitor banks, as overcompensation can lead to high voltages during light loading conditions. Capacitor banks are used to maintain voltage stability and power quality across the network.
- Undersized reticulation because of load growth

Recognising this, we need to ensure that the capacity of our network and the voltage levels at each point of supply are adequate to meet the existing and expected future customer loads. As such the following approaches are used:

- Proactively analysing the performance of our 33kV sub-transmission and 11kV distribution feeders using our network model
- Overlaying engineering investigations with customer enquiries for new or increased capacity
- Utilising smart meter data of our LV network to monitor voltage and load
- Investigating customer feedback and complaints
- Conducting specified studies addressing operational issues, for example exploring new back feed options
- Monitoring national and international applications of emerging technologies
- Actively engaging with our customers to understand their goals and future energy needs

Analysis and investigations can identify the need for network investments such as feeder voltage support (improved zone substation voltage control, regulators, or capacitor banks), distribution transformer upgrades, cable and line conductor upgrades, and new feeders.

Our power quality requirements are as follows:

- Electricity Safety Regulations requires that LV must remain within 6% of the nominal voltage (230V for single phase). This 6% steady state supply voltage range limit is also a requirement of the Electricity Industry Participation Code (2010) (the Code)
- AS/NZS 61000 and its Parts sets out the requirements for voltage and current waveform distortions
- Voltage and frequency requirements for DG (customer connections) are set out on our website and are in line with the the Code

Our network planning process

Planning for our future network is governed through our Asset Management Framework, as outlined in Section 5.

Our network planning process is how we design and optimise our network infrastructure to meet our customers current and future demands. The overarching goal is to ensure that we deliver electricity to all our customers, safely and reliably, while optimising the cost of construction, maintenance, and operation of our network.

This process involves several steps, outlined in the graphic below :

Figure 4: Our Planning Process.

Demand forecasting

Demand forecasting provides an estimate of the expected energy demand for the period of this AMP, allowing us to make informed decisions about capacity planning, network expansion and maintenance. This forecasting is based on a detailed bottom-up approach that takes into account historical demand, customer demographics and emerging trends.

Data collection

Our planning process starts with bringing together all the information we have about our network as well as our customer insights, demands and other factors like economic growth, changing consumption, weather data, population and household growth and new demands, like DG and EV uptake. Changes in legislation and regulatory requirements are also key inputs.

The demographic of our network varies from the supply of urban and rural households across the region, medium to large industry mainly in coastal, urban areas and agricultural irrigation through the region. Our irrigation customers and dairy factory consumption drives our seasonal peak load in summer.

Our Energy Roadmap

Our Energy Roadmap represents a significant new step in our planning process. Adopting a dynamic and responsive approach to network planning demonstrates our dedication to meeting the evolving needs of our customers and communities, in light of our long-term investment drivers.

The basis for our Energy Roadmap was a stocktake completed in 2021 of some of our region's largest energy-consuming process heat sites. This was done in collaboration with our South Island EDB peers, Transpower and the Energy Efficiency Conservation Authority (EECA). Building on this work, EECA launched the Regional Energy Transition Accelerator (RETA) project in South Canterbury in 2022. The project identified energy load sites which could potentially be converted to electricity through the phasing out of coal-fired boilers by 2037 as part of the Government's climate change policy.

In conjunction with this project, we have actively engaged with our customers, not only on their energy transition plans but their plans for sustainable fleets, DG, and business growth. These insights are a key input into the scenarios mapped in our AMP.

Insights from this engagement have led to a substantial uplift in forecast load demand from previous planning periods. We have responded by developing a model for our future infrastructure requirements. This is being adopted in a two-stage approach:

- Stage one - modelling of current state and modelling of a future 2040 state where we can make assumptions about the extent and scale of electrification within our region
- Stage two - the results from stage one are used to understand the areas of load growth at a GXP level on our network. It will include a data modelling solution where the different variables (timescales for the different elements of electrification) can be modelled in different combinations based on our assumptions. This will help inform decision-making for future infrastructure to minimise our risk of either not investing fast enough, or the cost of investing too soon

We will cover the key inputs into South Canterbury's energy requirements through to 2040. This will include considering Transpower developments, regional development plans, industrial requirements for growth and process heat conversion, DG and EV uptake, and resilience requirements due to the risks from climate change and natural disasters, such as an Alpine Fault rupture.

As these inputs change over time, we will continue to analyse and update our projected requirements for 2040 including:

- Estimated energy requirements by sector
- Peak load
- Estimated energy requirements by region / existing / future substation requirements
- Details of assumptions for each sector / region and rationale behind these assumptions
- Future SoS considerations while considering possible load shed alternatives, non-network solutions and demand management options available
- Network resilience

This roadmap will be maintained as a key element of our planning process for the future.

Modelling and options

Network modelling and options analysis

Utilising demand forecasts, we then establish our network system growth projects, which are subject to an options analysis including consideration of the possible implementation of non-network and new technology solutions.

A demand growth database and process is used to gather all required information regarding proposed loads and supply to be connected on the network. The database records all information regarding the load's characteristics, location, supply, and load requirements, and the expected timeframes for full load utilisation. To fully capture the risks associated with each load, we assign a probability to each load based on factors such as the likelihood of it materialising and its potential impact on our network. This information is then incorporated into our network modelling and options analysis. By doing so, we gain a more comprehensive understanding of the potential risks and benefits of each project.

We also operate a DG database to record all DG applications as per Part 6 of the Code. This data is then used to check compliance requirements and monitor hosting capacity in our network.

Our long-term planning options are based on three potential future scenarios:

Scenario options	Description
Speculative	The decisions of our customers are influenced by an economically favourable era in which productive investments are encouraged, promoted, and incentivised. Customers gain a clear advantage from expanding their business and/or altering the technologies they use. For example, industrial users perceive a clear economic benefit in shifting their process heat away from a carbon source and towards electricity. These customers have not committed but are in the early stages of discussions for the medium to long-term future. Speculative work is less than 50% likely to happen.
Possible	The decisions of our customers are influenced by a financially sound era in which productive investments may benefit them. Customers are being required to shift technologies even though the benefits of such expenditures are not readily apparent. For example, industrial customers believe that switching from a carbon source to electricity will cost them money but will also face regulatory penalties if they do not. These customers are confident of a connection and are in discussions with us regarding an application in the short to medium-term. Possible work is more than 50% likely to happen within five years of when we think it will happen.
Prudent	Customers have already decided to change and have demonstrated their commitment by investing in their infrastructure or are in advanced discussions relating to increased demand. For example, an industrial customer has already applied for an increase in capacity as they plan to shift their process heat away from a carbon source towards electricity. Prudent work is more than 80% likely to happen within two years of when the customer said it would happen. Note: Our AMP expenditure forecasts have been based on this prudent scenario.

Our proposed new demand loads are categorised by their likelihood as follows:

Descriptor	Time-based guide	Description	Annual probability	Likely Scenario
Almost Certain	Within two years	A customer already applied to increase their allocated network capacity.	>=90%	**Prudent**
Likely	Within five years	A customer actively discusses increasing their allocated network capacity.	60% - 90%	**Prudent** **Possible**
Possible	Within 10 years	Similar network capacity changes occurred elsewhere within NZ, and change drivers exist within the customer's market.	40% - 60%	**Possible** **Speculative**
Unlikely	Within 20 years	Although change drivers exist within the customer's market, a network capacity change hasn't yet occured elsewhere within NZ.	20%-40%	**Speculative**
Rare	After 20 years	Although technology can motivate a change, such a network capacity change is unlikely.	<20%	**Speculative**

The load forecast at the GXPs and zone substations is then established using historical demand data and applied in a linear regression as a base. Projected step increases are then added to the forecast.

Forecasting and modelling

We utilise a standard linear regression method to determine demand growth on the network. Network modelling is carried out using ETAP software. All assets up to the distribution transformers LV bus are currently modelled. Modelling is carried out on multiple scenarios based on customer feedback and smart meter data verification to establish a realistic plan and avoid over capitalisation of the network. All proposed loads are added to our master network model.

Load flow analysis is used to demonstrate the network's performance under worst case scenarios. Worst case scenarios are modelled as peak loading during LV control limits and trough loading during HV control limits.

Network Development Plans

Using our asset management demand forecasting, modelling, and options analysis, we then prepare Network Development Plans (NDP). NDPs are prepared for each of the seven GXP regions.

- Albury
- Bells Pond (Ikawai/Glenavy)
- Studholme (Waimate)
- Tekapō
- Temuka
- Timaru
- Twizel

Planning at a GXP level better reflects the impacts of regional variances in land use and economic activities than an aggregated plan would allow.

We need to ensure that the capacity of our network and the voltage levels at each point of supply are adequate to meet existing and future customer loads as forecast.

The process utilises the above presented methodologies in a systematic framework to produce the annual region NDPs for the entire network. The process follows the key steps outlined thus far, at a regional level. A summary is included below:

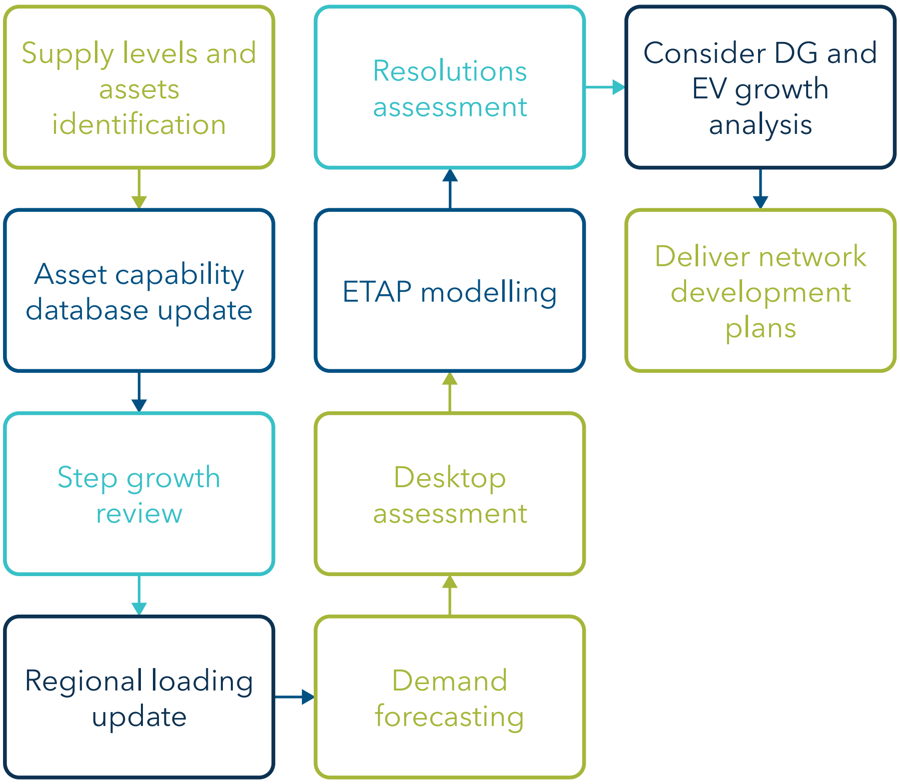


Figure 5: Network Development Planning Process.

Investment decision process

All network investments are divided into the following (in line with ID requirements):

- Customer connection (CC)
- System growth (SG)
- Asset replacement and renewal (ARR)
- Asset relocations (AR)
- Reliability, safety, and environment (RSE):
  - Quality of supply
  - Legislative and regulatory
  - Other reliability, safety, and environment

A database of opportunities and network projects is maintained to allow us to evaluate these projects based on a set of criteria.

The following Table, which is based on our Risk Management Policy for network investment, summarises the criteria we use for prioritising our projects. This is described further in Section 10.

Investment Criteria	Description
Safety	Projects that require execution to improve safety and/or remove hazards. Criteria include public safety, workplace safety, and network operating safety.
Risk reduction	Projects that allow the risk to the company to be reduced in accordance with our Risk Management Policy. This includes health and safety, reputation, environmental, compliance and financial impact.
Reliability of supply	Projects that improve network resilience in the face of faults, increased climate change-related weather events, Alpine Fault risk, and general use. Criteria include improve network condition, adaptability, flexibility, ease of use, resilience, and maintainability.
Security of Supply	Projects that ensure our network assets comply with our SoSS and improve the capacity of the network to meet stakeholders' expectations.
Efficiency	Projects that improve the performance of the network and cost efficiency to meet stakeholder needs. Criteria include network operating performance, configuration of network assets, improvement of network design, minimise technical losses, and a reduction in maintenance and operating time through selection of maintenance-free equipment with minimum operational requirements.
Economy	Projects that produce the best return in terms of network improvement for funds expended and provide a reduction in life-cycle costs through selection of "maintenance-free" equipment with lowest inspection and operation overheads.
Ease of project implementation	Projects that are the easiest to implement with respect to multiple contractors and stakeholders, high internal resources commitment, implementation time and high risk of exceeding planned SAIDI.

Build and maintain

The final process piece in the planning cycle is to implement the identified changes and projects and to continually monitor our progress, asset insights and feed back into the planning process.

Implementation

This involves building and maintaining our network assets in accordance with our AMP. At this stage projects enter our end-to-end value chain process, discussed further in Section 12 .

Continuous monitoring

We continuously monitor our network performance in line with our asset management strategies. Key insights from our network performance, additional load growth not forecast, reliability and other areas are consistently fed back into our planning process. Our AMP development process and annual NDP reviews help us to continually learn and inform our planning models. Additionally, we carry out regular asset inspections to identify any potential issues on our network.

Management of our LV network

LV networks were historically designed to accommodate stable, passive household loads with one-way electricity flow. However, the increasing adoption of technology such as EVs has led to a growing need to manage the significant additional demand that they can place on parts of the LV network. Additionally, the rise of residential DG, necessitates the management of two-way energy flows. Our LV network comprises a significant portion of our network assets and is the primary connection point for our residential customers. Enhancing the visibility and capabilities of the LV network has become increasingly important to meet our service level targets and facilitate customer energy choices.

Our NDPs identify the risks and opportunities to our LV network stemming from the increased penetration of DG and greater uptake of EVs across our region. However, our LV reticulation has undergone minimal upgrades over its life, which could limit our ability to accommodate emerging technologies and changing customer needs. The future may require a shift from traditional approaches to planning, maintaining, and upgrading our LV network, and this would likely result in a need for greater investment.

During this planning period we will focus on:

- LV monitoring
- Smart meter information gathering
- Developing LV usage scenarios

This work will support our response to specific LV issues that may arise through the deployment of:

- Non-network solutions, such as:
  - Phase balancing, where we distribute LV connections equally between the three phases of an LV network
  - Demand side management techniques to regulate EV chargers. This can include implementing measures such as ripple control and appropriate pricing, enabling EV charger control through smart metering, and promoting the use of smart EV chargers
  - Non-Network solutions and energy storage solutions, either at the household level or on the LV network, can help address various challenges related to energy supply and demand. By promoting the use of these solutions, we can reduce the strain on the network infrastructure, better manage peak demand, and improve the overall resilience of our network
- Asset solutions, such as:
  - Install LV regulators at strategic locations
  - Deploy distributed battery systems
  - Reduce LV circuit lengths by reconfiguring localised sections of the LV network
  - Use of on-load tap changing distribution transformers
  - LV conductor upgrades

Future LV roadmap

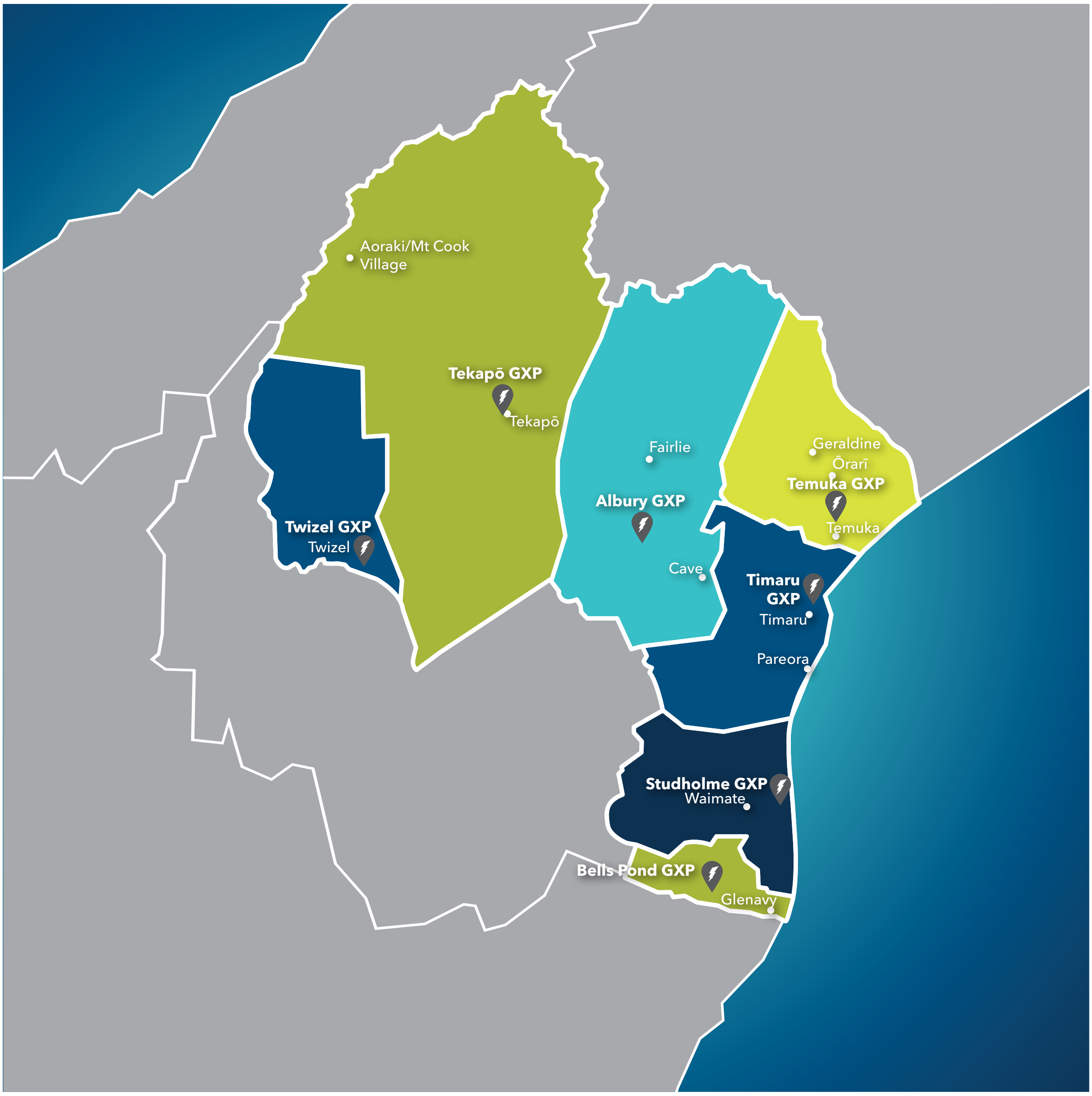
Increased LV and smart meter data monitoring will enable us to observe the use of electricity in real-time, at a household level. This will allow us to see and respond to changes of activity on the network, and help us provide customers with a more flexible, dynamic range of choices for managing their energy needs.

Greater analysis of this data will enable us to develop a better understanding of baseline LV demand and will allow us to track changes as adoption of EVs, solar PV, battery storage and energy sharing become more prevalent, and patterns in customer behaviour emerge. Smart meter data analysis will also provide us greater visibility over power quality issues for LV customers. This data will feed into our demand forecasting and maintenance planning, helping to inform our investment decisions, and prepare a LV roadmap to support our future network.

07. Our future network

Our growth by region

This section outlines our network growth projects by region for the next 10 years. These projects are categorised by GXP, which reflects the impacts of the differences in our regions, their land use, and economic activities.



The growth expected on our network over this next AMP period is significant. The following below shows the potential expected uplift from a base of 144MW to 416MW over the next 10 years. This demonstrates the importance of our Energy Roadmap and capturing a holistic view of the potential impacts on South Canterbury's energy requirements. This will provide the insights needed to build the best possible solution, considering the alternatives available outside of asset growth, such as new sources of supply in solar, wind or other and working with key energy customers to balance our load at peak times.

Overall network peak demand forecasts

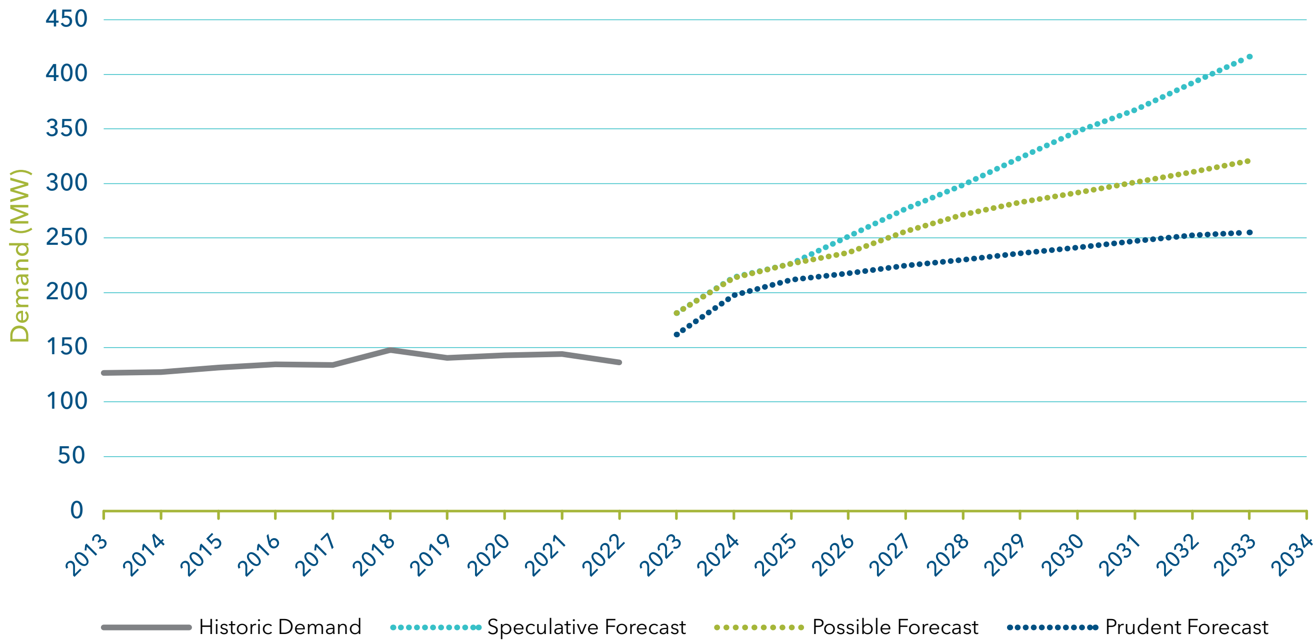


Figure 1: Overall network peak demand forecasts.

This section considers the data insights as discussed in Section 3 and outlines how our Energy Roadmap has resulted in three scenarios for growth which we have used in developing our regional plans. We also highlight our plans for the future management of our LV network.

Our energy roadmap

Our energy roadmap scenario analysis supports in structuring an assumption process in which we generate several hypotheses and choose one or more alternatives from an extensive set of possibilities. Our scenario analysis enables us to prioritise short-term, feedback-based learning above long-term projections of change and its consequences.

As set out in Section 6, we have developed several scenarios by identifying the likely change drivers influencing our customers' decisions. These scenarios depict potential circumstances where customers are forced to make various development decisions. The scenarios test our assumptions, help us make better decisions, and highlight our strategic options as we embrace change in our network.

Energy roadmap budget

The following below depicts the budget forecast for the three distinct scenarios we have considered across our whole network and applied to our regional plans in this section. It also depicts the budget we forecast in last year's AMP. Inflation and a step increase in load demand have significantly increased our budget. The budget for this financial year (FY24) is based on the "prudent" scenario depicted. This scenario represents our current knowledge as well as the developments to which our customers have already committed. It has been designed with specific milestones at which non-network solutions and flexibility services can be considered to reduce peak demand. Future customer demands, decarbonisation and electrification developments may require us to bear some of the expenses described in the "possible" scenario. As customers commit to capacity expansions, we will adjust our budget (and incorporate budget items from the "possible" scenario).

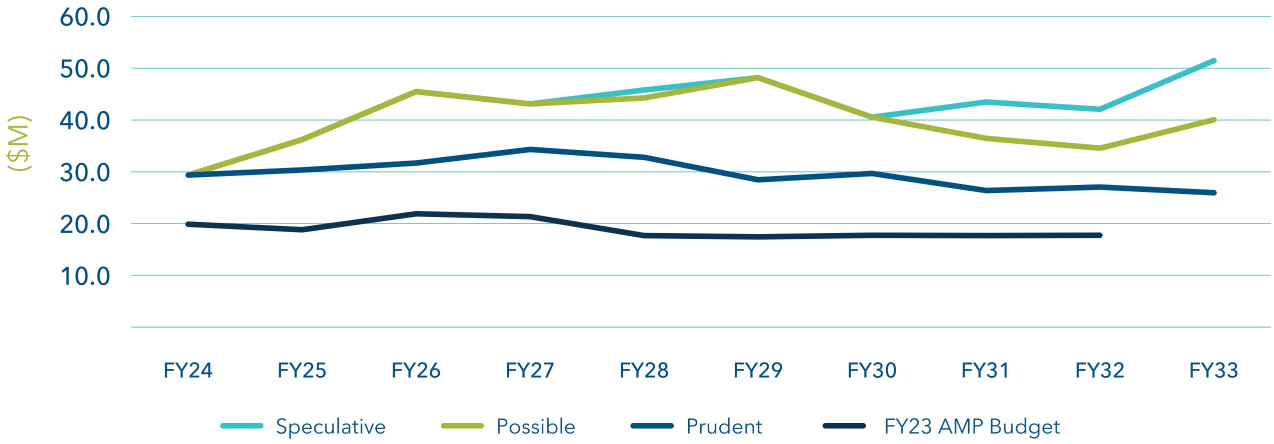


Figure 2: Energy roadmap budget forecast.

Our regional Network Development Plans

This section summarises the network development plans for each of our seven planning regions. Each planning region is supplied by its own GXP from Transpower as shown in Figure 3 below. We have Network Development Plans (NDPs) for each region.

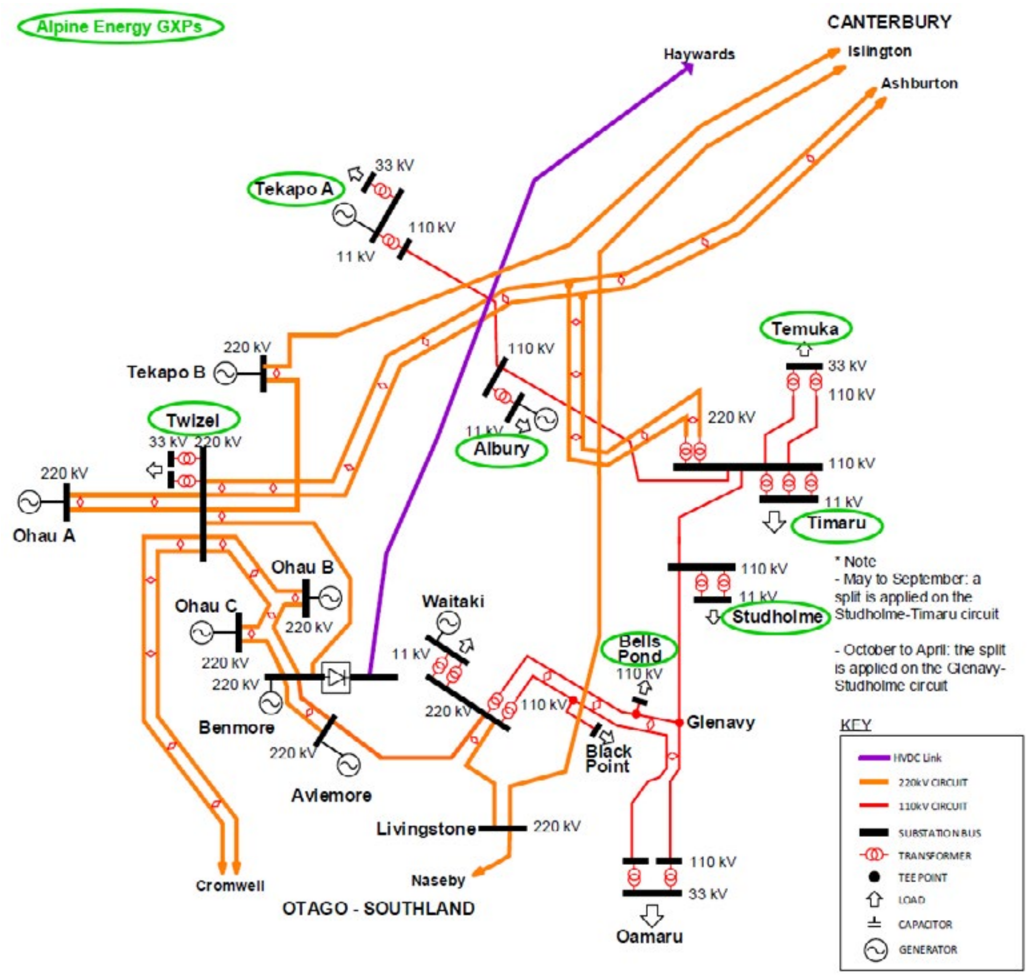


Figure 3: South Canterbury transmission grid and GXPs supplying our network.

The figure above reflects the transmission grid, our GXPs and corresponding substations.

Timaru GXP (TIM)

Overview

The majority of our customers live in the Timaru area. Timaru is the hub of South Canterbury, connecting the road networks west, north, and south. Timaru comprises a Central Business District (CBD), a main residential population, and a range of industries and commercial businesses including but is not limited to:

- Food and meat processing plants
- A container, timber, fuel, and bulk cement port
- A brewery
- A wool scour

Most of the load growth in the area comes from industrial development in the Washdyke and Timaru Port areas.

The regional zone and switching substations are:

- Timaru Zone Substation
- Timaru ATM 11/33kV T1 Zone Substation
- Timaru ATM 11/33kV T2 Zone Substation
- Pareora Zone Substation
- Pleasant Point Zone Substation
- Grasmere Switching Station
- North Street Switching Station
- Hunt Street Switching Station
- Washdyke Switching Station

Security of Supply

The SoS for Timaru, Pareora and Pleasant Point Zone Substations are detailed in the table below:

Zone sub/load centre	Actual	Target	Comment
TIM 33kV step up Zone Substation	N-1 for Pareora N for Pleasant Point	N-1 for Pareora N for Pleasant Point	Two step-up transformers feed a split 33kV bus arrangement. Pareora is fed off both buses, while Pleasant Point is only fed off one bus.
Timaru residential	N	N-1 (switched)	There is extensive inter-connectivity on feeders from Timaru, Grasmere, North Street and Hunt Street Zone Substations.

Zone sub/load centre	Actual	Target	Comment
Timaru rural	N - 0.5	N - 0.5	Limited fault back up from adjacent feeders from Timaru and then as a second resort Pareora, Pleasant Point and Temuka.
Washdyke/Seadown	N	N - 1 (switched)	Four new 33kV cable circuits from Seadown to Timaru to run at 11kV were installed in 2017. The lack of a switchboard with a full bus at the Washdyke Switching Station limits the SoS.
Timaru CBD (Grasmere, Hunt St and North St)	N - 1 (switched)	N -1 (switched)	There is inter-connectivity on the 11kV feeders and 400V reticulation.
Pareora 33/11kV Zone Substation	N - 1 for transformers 10MVA for sub-transmission circuits	N - 1 for transformers	Some load can be supplied using 11kV feeders from Studholme and Timaru in an emergency.
Pleasant Point 33/11kV Zone Substation	N	N	Some load can be supplied using 11kV feeders from Pleasant Point, Temuka and Timaru Zone Substations in an emergency.

Timaru GXP demand forecast

The demand forecasts for the Timaru GXP are shown below. As previously discussed, there is a significant step change in growth expected.

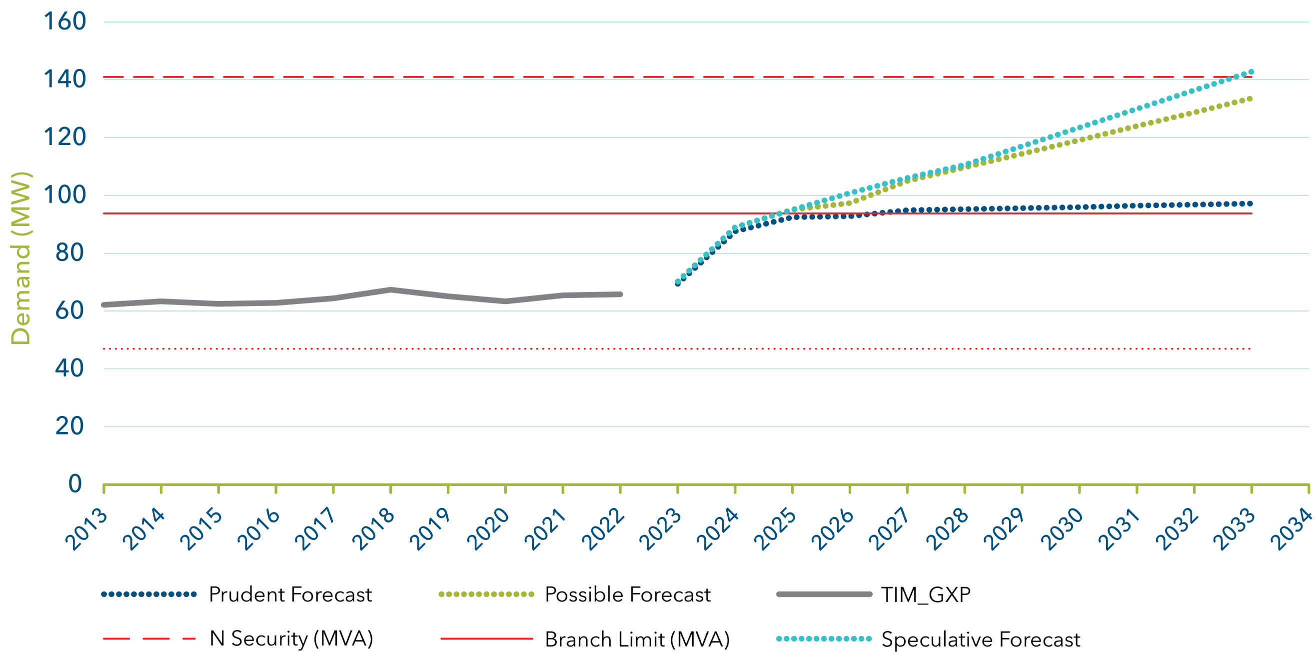


Figure 4: Timaru GXP demand forecast.

Existing constraints and key projects

Growth within the Timaru GXP is already stressing the capacity of our network. The Timaru District Council has adopted an in-fill policy, promoting higher density residential in the existing urban areas. This policy could result in required network investment on the LV reticulation.

With the continuation of the GIDI Fund, there have been significant enquiries around load changes, driving up the demand forecast for the planning period and bringing forward potentially significant network upgrades to meet this demand, especially at Washdyke. Decarbonisation-related load growth has absorbed all the N-1 capacity available at the Washdyke Switching Station.

Our Timaru GXP network is made up of two historical line businesses which were merged in 1993 – the Timaru Municipal Electricity Department (MED) and the South Canterbury Electric Power Board (SCEPB). The existing asset configuration comprise lines through a corridor in a SCEPB area to supply an encircled MED area and has three key characteristics:

- The compact MED is supplied at 11kV from the Timaru GXP, mainly via underground assets
- Due to a difference in phase angle between the then MED (Timaru metro area) and the surrounding SCEPB areas, (Temuka and Geraldine) the networks cannot be easily meshed to improve SoS. These networks must first be turned off before they can be connected to restore supply
- There are areas of supply at the boundary of the historical areas that can be improved by greater integration of the assets of the two legacy networks (for example, by upgrading 11kV lines and cables, and introducing additional, or upgraded, points of connection between the two networks). The key projects in our roadmap in delivery the step change required are detailed below.

33kV supply from GXP

Developing a 33kV supply from Timaru GXP will be a key project for this AMP period. Currently we have all Timaru Substation's load feeding off the 11kV switchboard at Timaru. By securing a separate 33kV supply at Timaru GXP from Transpower, we will be able to:

- Transfer Pareora and Pleasant Point Zone Substation load from the 11kV bus to a new 33kV supply
- Split the Hadlow feeder, once space is available on the 11kV Timaru GXP board, as this would allow us to fix an unbalanced loading issue on this 11kV board
- Transfer Washdyke load from the 11kV to the newly created 33kV supply.

Scenario	Drivers	Project	Timing	Estimate ($)
		Timaru GXP		
Prudent	Almost certain load growth	Upgrade the 11kV supply from Timaru to 33kV (cost dependent on Transpower)	2026	To be determined
Prudent	Almost certain load growth	Transfer Pareora and Pleasant Point 33kV sub-transmission to the new 220/33kV Timaru GXP (≈ 14MVA)	2026	0.2M
Possible	Possible loading imbalance	Split the Hadlow feeder once there is space on the 11kV switchboard	2027	0.8M
Speculative	Possible load growth	Resupply and upgrade the sub-transmission to Hunt Street from Timaru GXP and remove its reliance on Grasmere	2028	1.5M

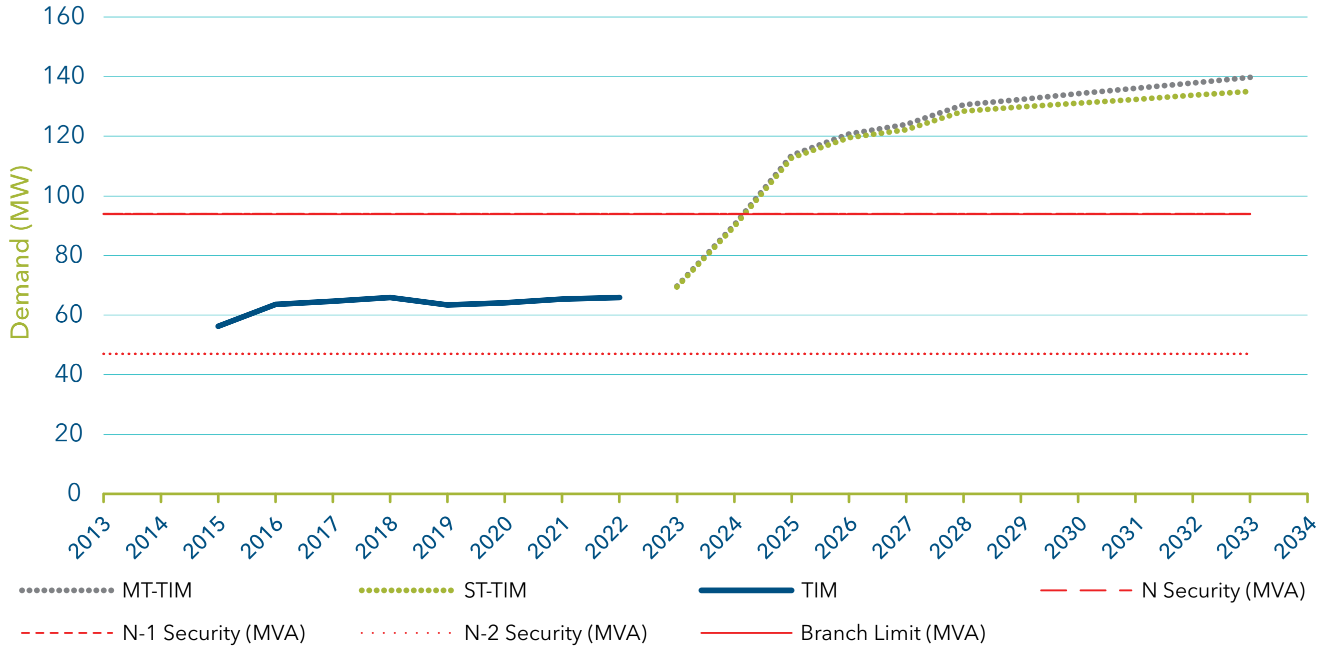


Figure 5: Timaru Zone Substation Demand Forecast.

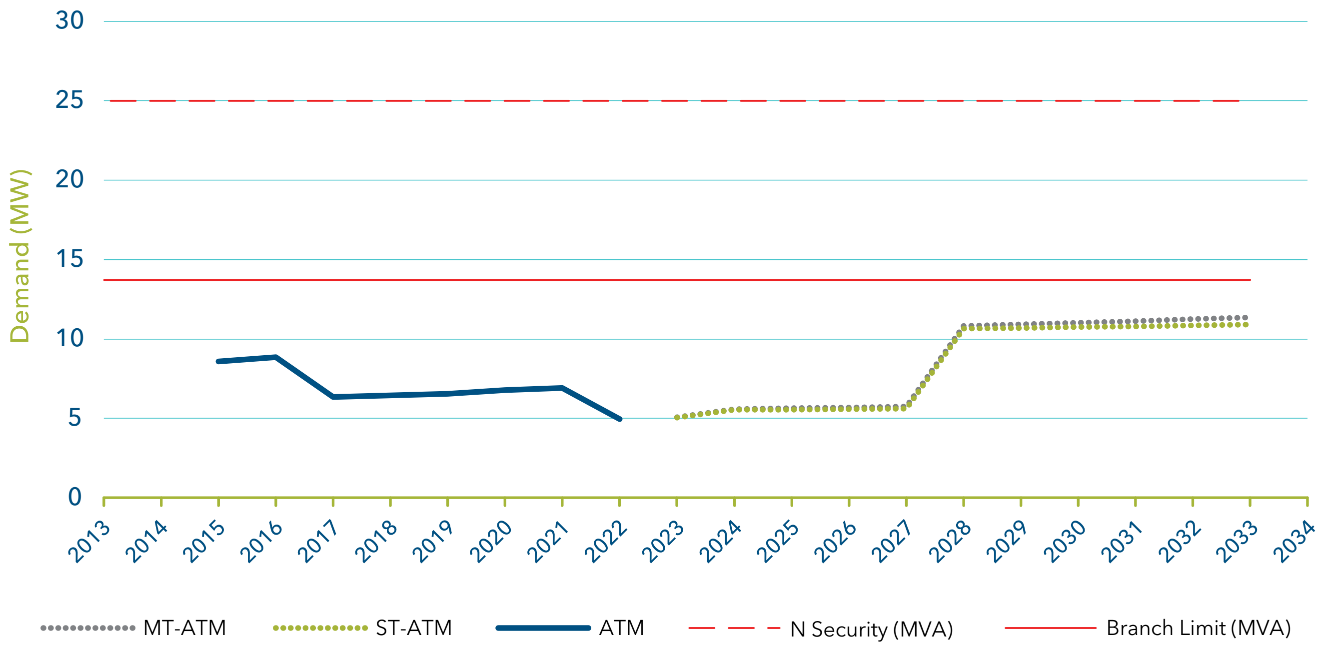


Figure 6: Timaru ATM Zone Substation Demand Forecast.

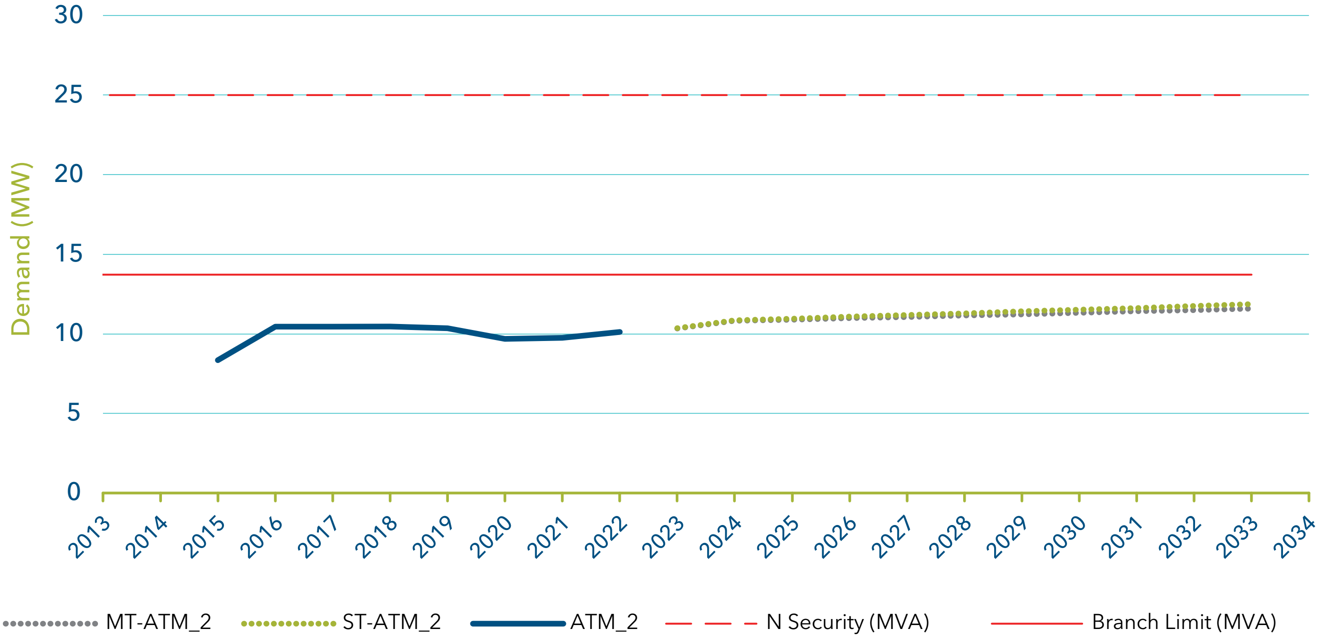


Figure 7: Timaru ATM 2 Zone Substation Demand Forecast.

Washdyke Switching Station and Zone Substation

We plan to upgrade our Washdyke Switching Station in 2024 to increase our SoS, which will soon be constrained by the 11kV cable capacity between the Washdyke Switching Station and the Timaru GXP.

The 33kV supply from the GXP will supply the new Washdyke Zone Substation via the current 33kV cables. This is planned for 2026/27.

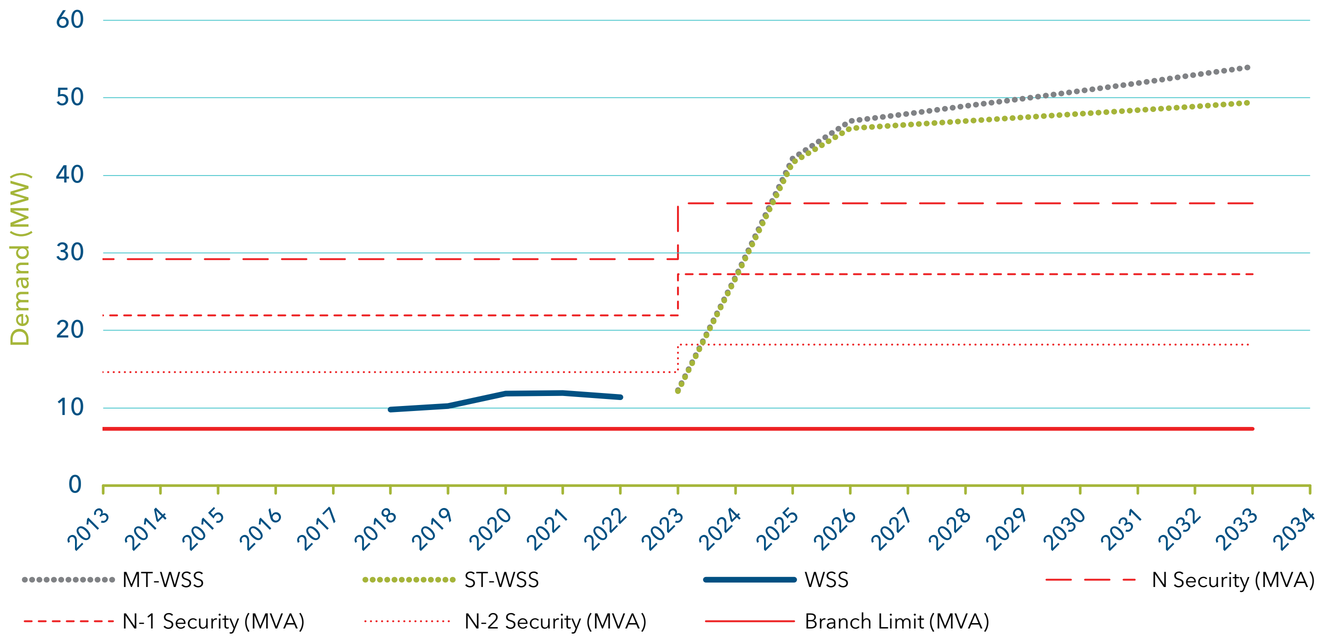


Figure 8: Washdyke Switching Station Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
New Washdyke 11kV Switching Station				
Prudent	Load growth Possible N-1 supply security	Install a new 11kV Washdyke Switching Station.	2024	4.0M
New Washdyke 33kV Substation				
Prudent	Almost certain load growth	Build new substation.	2025	5.0M
		Install South Washdyke 11kV ring and future cable.	2025	4.0M
		Install North Washdyke 11kV feeders.	2026	3.0M
		Transition sub-transmission from Timaru GXP to Washdyke from 11kV to 33kV.	2027	0.45M
		Move load from Timaru 11kV to Timaru 33kV.	2027	0.4M
		Install 33kV cable between the Washdyke Zone Substation and 11kV Washdyke Aorangi Satellite Substation.	2028	2.5M

These projects will create approximately 30MW additional capacity on the 11kV board supplying Timaru.

Pareora feeder upgrade

Our Pareora Zone Substation demand is running close to our N-1 security limit due to a constraint on our overhead feeder connecting Timaru GXP to Pareora. We will replace a section of this line to regain our N-1 supply security. The sub-transmission circuits to Pareora Zone Substation are also voltage constrained if total load exceeds 20MW, or 10MW in a contingent event (for example, one of the circuits, or a Pareora power transformer out of service).

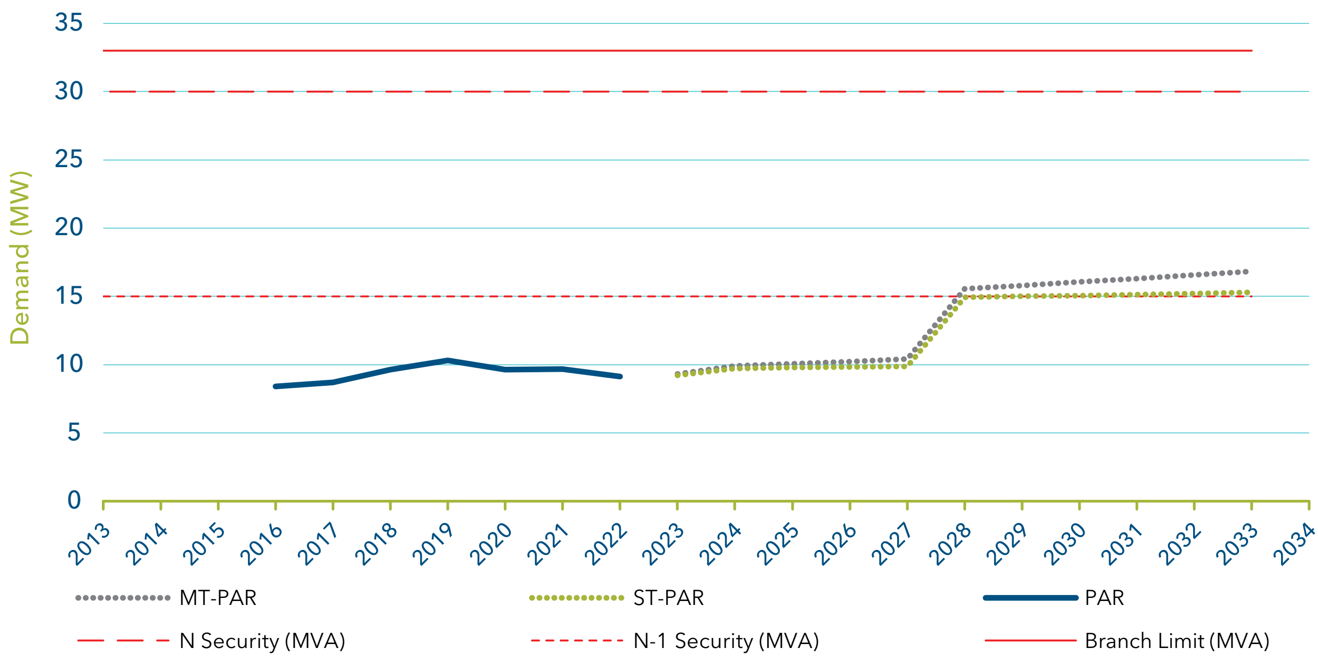


Figure 9: Pareora Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Pareora Zone Substation		
Prudent	Likely N-1 supply security	Upgrade the first part of the sub-transmission to Pareora (>20MVA, 1.3km).	2026	1.0M

33kV Timaru Ripple Plant

A new 33kV ripple plant will be installed once a 33kV Timaru GXP feeder is available, to replace our 11kV Timaru Ripple Plant. This would allow us to control all the load within the Timaru area (and not just the 11kV distributed load).

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		New Timaru Ripple Plant		
Prudent	Almost certain load control	New 33kV ripple plant (instead of 11kV ripple plant).	2026	0.6M

Pleasant Point Zone Substation

The Pleasant Point Zone Substation transformer is aged and will be replaced. The substation does not have N-1 supply security, if load growth continues, we would install a second feeder from Timaru GXP to the Pleasant Point Zone Substation and also build a new substation, replace the circuit breakers (CBs) and install a second transformer.

Figure 10: Pleasant Point Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Pleasant Point Zone Substation		
Prudent	Possible N-1 supply security	Replace Pleasant Point power transformer.	2027	1.5M
Possible		Rebuild substation.	2029	5.0M
		Install second sub-transmission 33kV circuit from Timaru to Pleasant Point (18km).	2029	1.5M
		Install second 9/15MVA power transformer.	2030	1.3M

Timaru urban growth response plan

In Timaru city there are various other areas of expected growth, outside of the Washdyke area. These are: Timaru Port; the Redruth industrial area at the south of Timaru; Timaru District Council investment in CBD regeneration (Timaru CityTown Project); continued residential growth through housing provision and the transport electrification. If loads outstrip our 10-year plan we would respond with a 33kV ring between Timaru GXP, the North Street Zone Substation, the new Port Zone Substation, the Redruth Zone Substation and the Pareora Zone Substation, to deliver the capacity needed. These projects are listed below:

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		New Timaru Port Zone Substation		
Prudent	Load growth	Secure site for substation at Timaru Port.	2025	0.5M
		Install 33kV cable between North Street Substation and new substation, initially energised at 11kV.	2027	2.0M
		Build new substation.	2028	5.0M
		Increase the 11kV capacity to the Timaru Port.	2028	1.5M
		Timaru CBD		
Prudent	Almost certain reliability	Install 11kV cables linking Timaru GXP to North Street (aligning timing with Timaru District Council CityTown project to maximise cost efficiencies).	2025	To be determined
			2026	To be determined
		New Redruth Zone Substation		
Prudent	Almost certain load Growth	Prepare for substation at Redruth.	2030	0.5M
Prudent	Possible N-1 supply security	Install 33kV supply cable between the new Port Substation and Redruth Substation, initially energised at 11kV.	2033	2.0M
Possible	Possible load growth	Build new substation.	2033	5.0M
		Install cable between North Street Substation and new substation.	2033	2.0M
		Move the 11kV load from North Street Substation to the new substation.	2033	0.6M
Possible	Possible N-1 supply security	Install 33kV supply cable between Redruth Substation and Pareora's feeder.	2033	0.5M

North Street Switching Station/Port upgrade to a 33kV Zone Substation

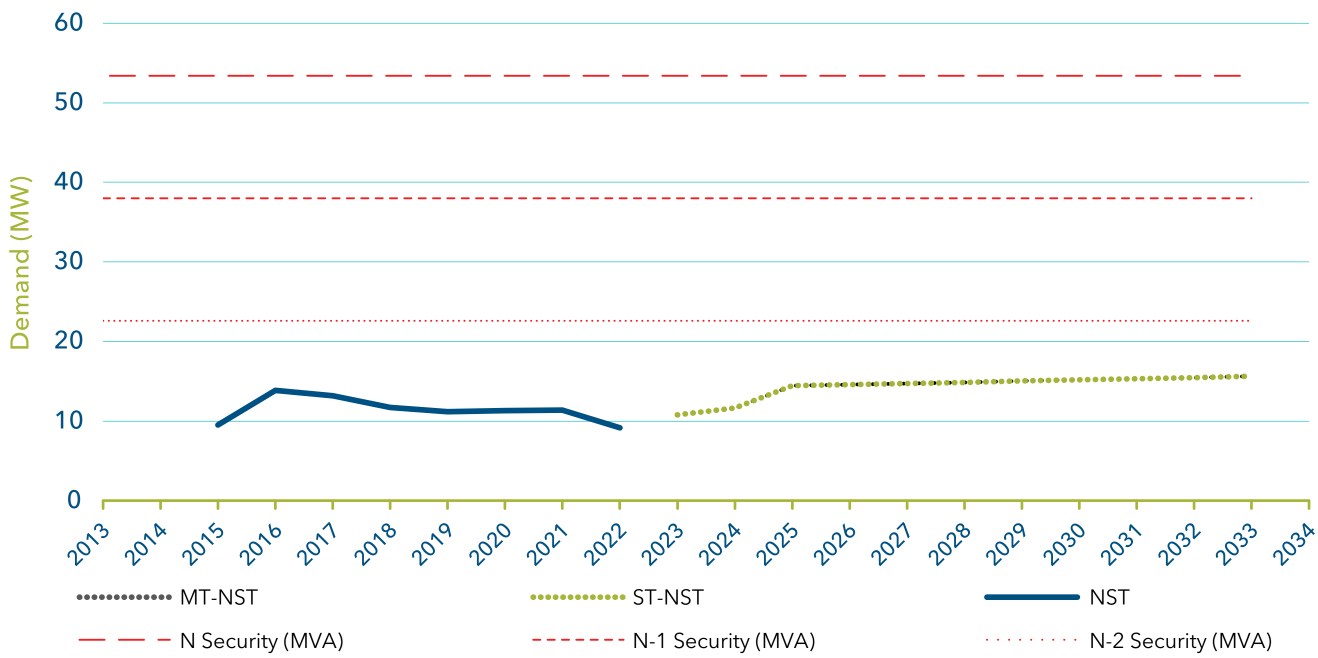


Figure 11: North Street Switching Station Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		North Street Zone Substation		
Prudent	Possible load growth	Install cable between North Street Substation and new substation, initially to a switching station to increase capacity. Install 33kV supply cable between the North Street Substation and the Timaru Port initially energised at 11kV.	2025	1.6M
		Install 33kV CBs.	2032	1.6M
Possible	Possible load growth	Install 33/11kV power transformer.	2032	1.5M
		New Sophia Street Switching Station		
Prudent	Almost certain load Growth	Prepare for switching station at Sophia Street.	2028	0.4M
Prudent	Possible load growth	Install 11kV CBs.	2028	2.0M
Possible	Possible load growth	Build new substation. Establish a CBD switching station in Sophia Street (allowing for increased EV charging capacity).	2028	1.1M
Possible		Move the 11kV load from North Street Substation to the new substation.	2028	0.6M

Timaru 11kV cable upgrade – Hunt Street and Grasmere Switching Stations

Ageing cables, resilience and SoS constraints will be addressed by upgrade of the 11kV sub-transmission cables between Timaru GXP and Hunt Street Switching Station. This would remove our reliance on the feeders feeding the Hunt Street Switching Station through the Grasmere Street Switching Station.

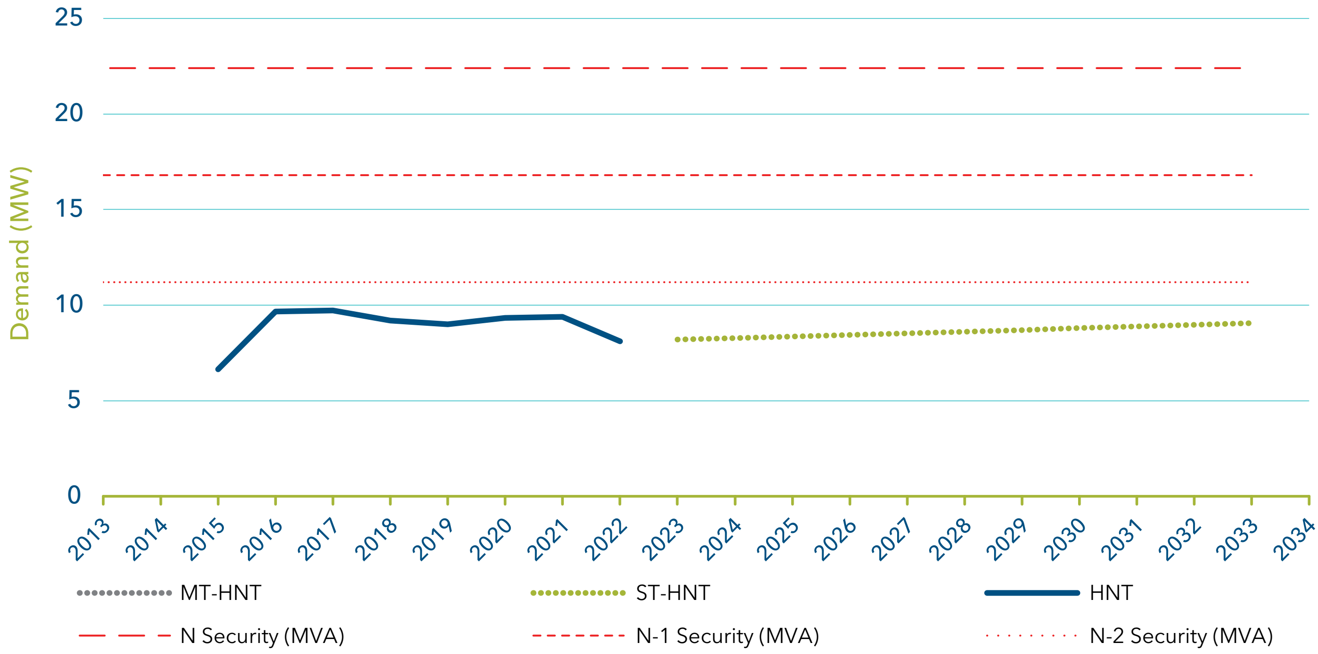


Figure 12: Hunt Street Switching Station Demand Forecast.

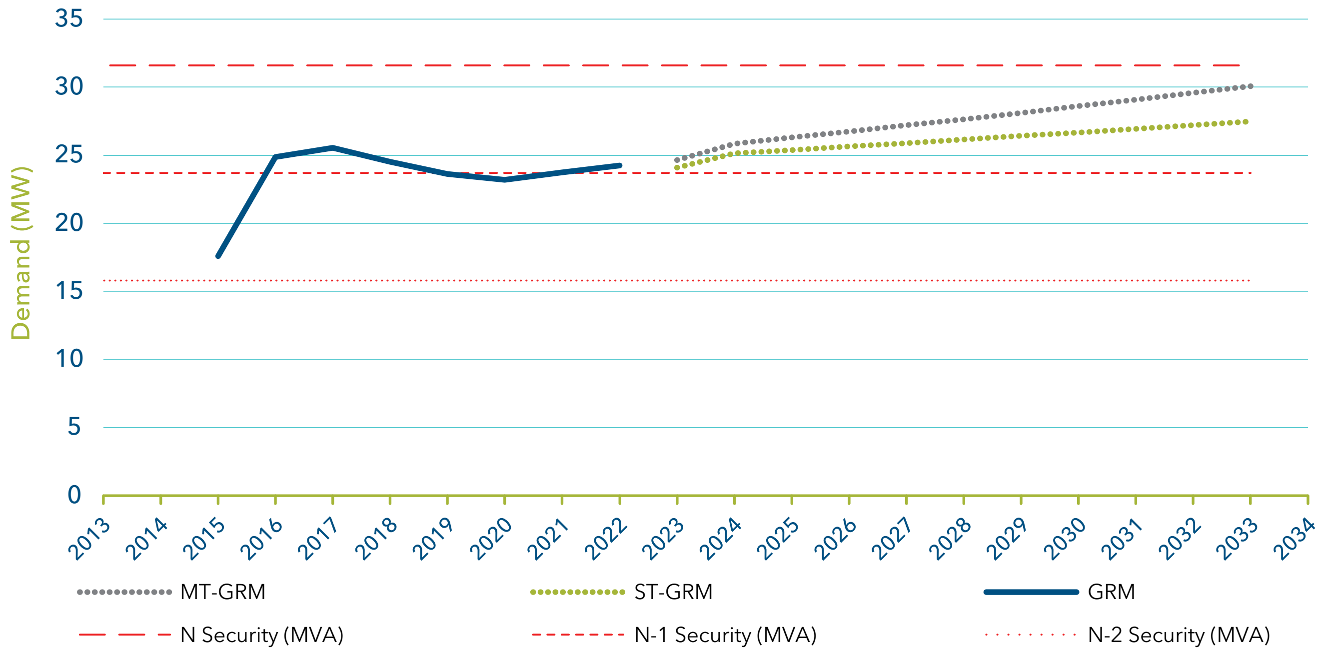


Figure 13: Grasmere Street Switching Station Demand Forecast.

Aorangi Road Zone Substation

Industrial decarbonisation and DG-related enquiries indicate that we may need a second 33kV zone substation near Aorangi Road in Washdyke within the 10-year planning period. A new 33kV Aorangi Road Zone Substation will alleviate the current demands placed on our network. There is interest in the connection of DG within the Washdyke area.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
New Aorangi Road Zone Substation				
Prudent	Almost certain load growth	Prepare for substation at Aorangi Road.	2025	0.4M
Prudent	Possible load growth	Build new substation.	2029	5.0M
		Install 11kV cable between Washdyke Substation and new Aorangi substation.	2029	2.0M
		Move 11kV load from Washdyke Substation to new Aorangi substation.	2029	0.4M

Rosebrook Zone Substation

Residential load growth (due to residential subdivisions that are taking place and EV chargers at LV) also indicates that we may need a 33kV Zone Substation in Rosebrook. This substation could be connected to the 33kV Pareora feeder to form part of the future 33kV ring in the long-term, however a Switching Station would be installed first to facilitate potential non-network solutions and energy storage solutions.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
New Rosebrook Zone Substation				
Prudent	Almost certain load growth	Secure site for substation at Redruth.	2027	0.5M
Speculative	Possible load growth	Build new substation.	2033	5.0M
		Install 11kV cable between Rosebrook and Timaru Substation.	2032	3.0M

Bells Pond GXP (BPD)

Overview

The Bells Pond (Glenavy/Ikawai) region in the Waimate District is predominantly characterised by farm irrigation. The Oceania Dairy Limited (ODL) factory is located near Glenavy.

The largest irrigation scheme within the Bells Pond Region is presently the Waihao Downs irrigation scheme.

Bells Pond demand forecast

The demand forecasts for the Bells Pond GXP are shown below.

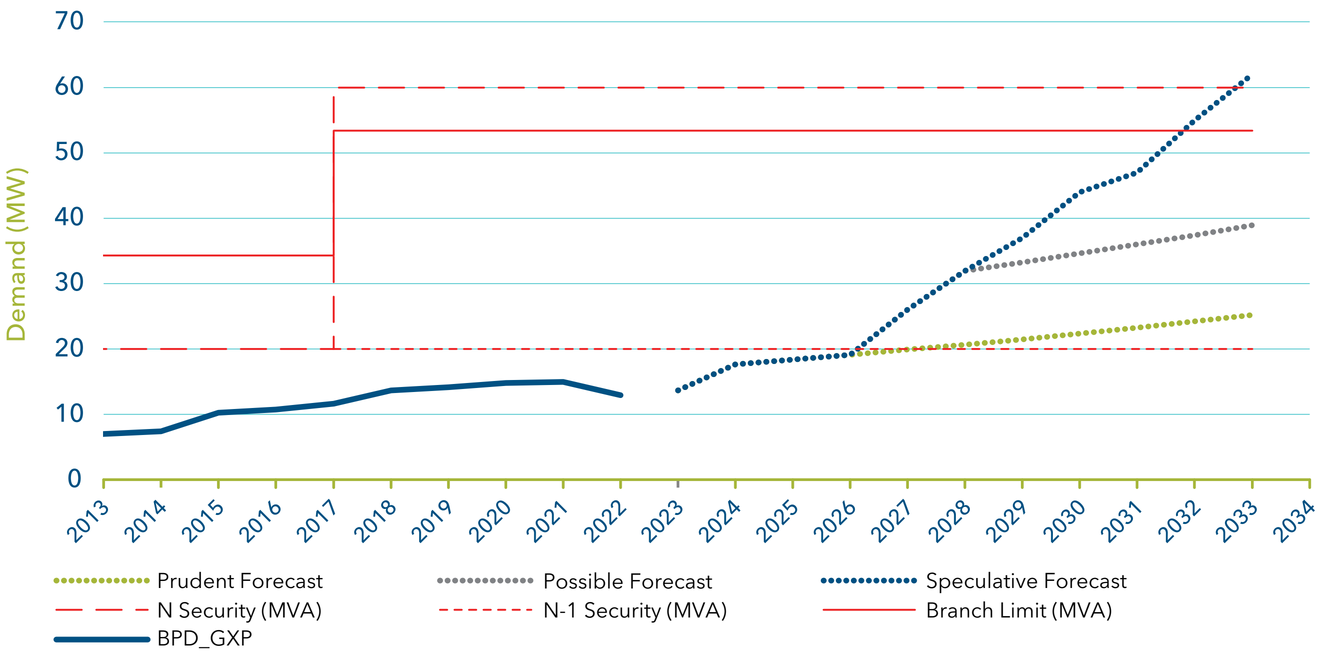


Figure 14: Bells Pond GXP Demand Forecast.

Demand forecast for the Bells Pond GXP and regional zone substations is for low-level growth. Most of the load resulting from dairy conversions and irrigation schemes have been accounted for. To the best of our knowledge, no large irrigations schemes are planned in the region.

Security of Supply

The table below outlines the SoS for the Bells Pond Zone Substation.

Zone sub/load centre	Actual	Target	Comment
Bells Pond	N-1	N-1	Security target is met for this planning period in accordance with our SoSS. Transpower has transmission configuration changes that would allow some or all supply to be restored. Transpower has evaluated as 'Low Economic Consequence'[1] and hence do not have a target of providing a higher security for it during this planning period.
Bells Pond - Cooneys Road	N	N	Security target is met for this planning period in accordance with our SoSS.
Bells Pond (11kV)	N-1	N-1	Security target is met for this planning period in accordance with our SoSS.
Bells Pond (33kV)	N-1	N-1	Security target is met for this planning period in accordance with our SoSS.
Cooneys Road	N	N-0.5	Security target is met for this planning period in accordance with our SoSS.

Existing and forecast constraints

Bells Pond GXP cannot support load growth, or the installation of DG, within its supply area. An upgrade of one of the Bells Pond transformers is required to be completed by Transpower.

Bells Pond GXP and Studholme GXP currently have a transmission limit imposed by Transpower due to voltage quality and thermal overloading issues during the summer peaks on the Bells Pond-Waitaki and Oamaru-Studholme-Bells Pond-Waitaki 2 circuits. Transpower has implemented a special protection scheme (SPS) to curtail load if one of the two Waitaki 110kV circuits is lost. The SPS will, in certain instances, allow us enough time to run our ripple injection plant to shed irrigation load, thereby maintaining supply to dairy processing plants and milking sheds, rather than turning off all load indiscriminately.

The Bells Pond rural area has backup supply from Studholme, but this spare capacity at Studholme will be eroded with any significant development by Fonterra at their Studholme dairy factory.

The forecast load growth is mainly related to border dyke irrigation conversions to pivot irrigators. Other increase load forecast is a result of increased load at Oceania Dairy Limited expansion (1 MW) and the committed capacity as per the supply contract that may be used for a second drier (3.5 MW). A further investment will be required when Oceania Dairy Limited requires to increase their SoS.

The Waihao Downs irrigation scheme currently takes up to 3.2 MW when all the pumps are running. A future stage 2 to this scheme could speculatively add another 3 MW to Bells Pond. It is unlikely that this future stage 2 would proceed, due to the implementation of the National Policy Statement for Freshwater Management, and Environment Canterbury's Land and Water Regional Plan. We have not received a network application for additional demand.

[2] Economic Consequence is the amount of load being served at a Points of Service (POS) multiplied by the VoLL at that POS, and is the expected dollar cost of an unplanned interruption at that POS.

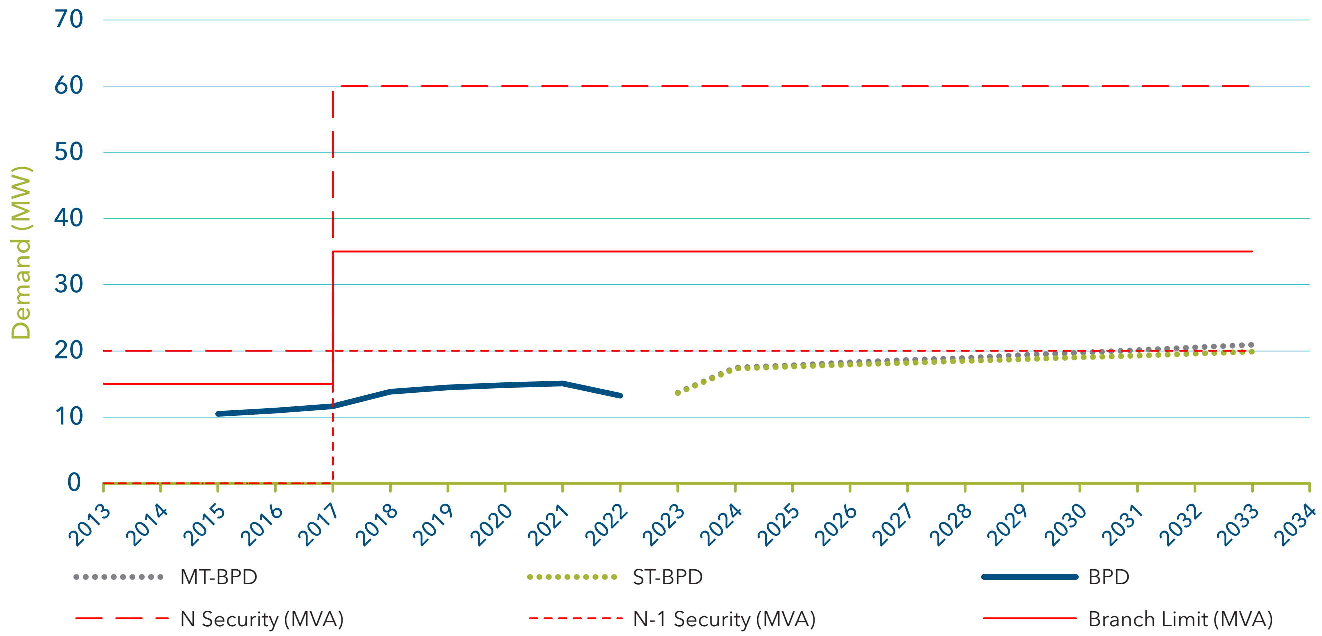


Figure 15: Bells Pond Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Bells Pond Zone Substation		
Possible	Possible DG	Upgrade power transformer (T2) to 40MVA (cost dependent on Transpower).	2030	To be determined

Cooneys Road Substation upgrade

Potential decarbonisation and DG within the Cooneys Road Zone Substation area would necessitate upgrading the Cooneys Road Substation's supply from 33kV to 110kV. We would then be required to build a new substation to house the new 110kV zone transformers required. The Cooneys Road Zone Substation would necessitate customer funding to proceed. The customer may also require an alternative electrical supply (from Studholme GXP) to improve their SoS.

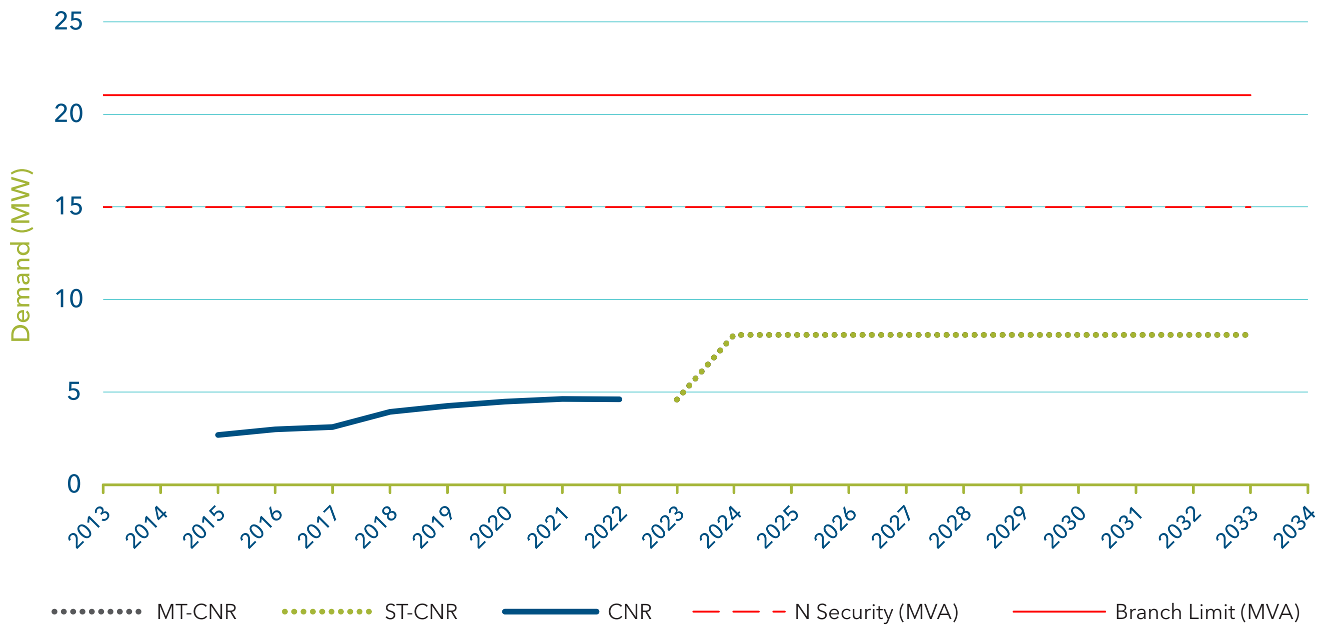


Figure 16: Cooneys Road Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Cooneys Road Zone Substation		
Speculative	Possible DG	Convert existing overhead circuits to 110kV.	2027	Customer funded
		New substation 110/33kV, 2 x 40MVA power transformers.	2028	
		Upgrade 2 x power transformers to 20/35MVA 33/11kV.	2028	
Speculative	Unlikely SoS upgrade	New 33kV overhead circuit to Studholme GXP (>8MVA).	2029	

Studholme GXP (STU)

Overview

The Studholme region encompasses most of the Waimate District, including urban Waimate. The region includes a significant amount of irrigation load, with agriculture, including dairy, sheep and beef, and cropping supporting economic activity in the region.

Fonterra operates the Studholme dairy factory, which is located close to the Studholme GXP.

Security of Supply

The following table outlines the Studholme GXP SoS:

Zone sub/ load centre	Actual	Target	Comment
Studholme GXP	N	N-1	SOS is not met for this planning period in accordance with our SoSS. Transpower has evaluated this GXP as 'Low Economic Consequence' and hence does not have a target of providing a higher security for it during this planning period. We will discuss opportunities to reinstate N-1 SoS with Transpower to align with our SoSS.

Studholme demand forecast

The demand forecasts for the Studholme GXP are shown below.

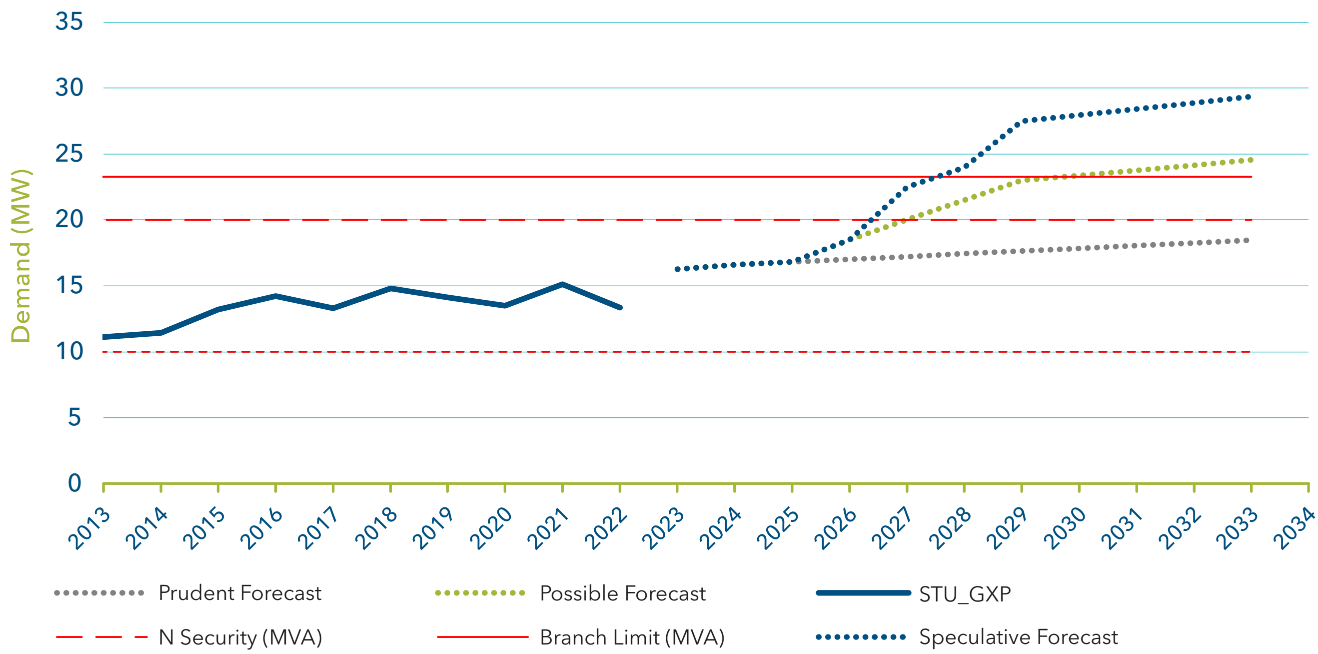


Figure 17: Studholme GXP Demand Forecast.

Existing and forecast constraints

Load growth has eroded the N-1 supply security within the Studholme GXP area. Transpower plans to replace the existing transformers at the Studholme GXP as part of their end-of-life transformers replacement project between 2025 and 2026. Until then, we do not anticipate any capacity constraints in the region. These new transformers will have a capacity of 40MVA, which will help to restore the N-1 supply security.

Following Transpower's transformer upgrade, we would be able to accommodate decarbonisation or DG-related developments within the area. EV uptake can be accommodated through to 2025 on the basis of existing capacity at the GXP and zone substation level. However, upgrades or other emerging load control technologies may be required on LV reticulation in the Waimate residential area.

The demand in this region is summer peaking, stemming from the established load at Fonterra's Studholme dairy factory, arable/dairy farming, and irrigation loads. Growth or decarbonisation activities at the Fonterra's Studholme site would require GXP upgrades due to the significant step change.

Throughout this GXP region, there is a struggle with keeping the voltage within the regulatory limits. This is evident by the number of 11kV voltage regulators deployed in the region already. The feeders to the north of Studholme and south of Pareora will require network investments if new connection requests for additional load are received. A request for proposals for non-network solutions will be issued when the maximum number of voltage regulators is reached. If needed, we could also deploy Statcoms for voltage control.

Our roadmap for the Studholme area

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Studholme Zone Substation		
Prudent	Almost certain SoS upgrade	Install 2 x 40/48MVA; 110/33/11kV power transformers.	2026	Transpower

Temuka GXP (TMK)

Overview

The second largest population group in South Canterbury lives at Temuka, 20km north of Timaru. Temuka is surrounded by plains used predominantly for arable and pastoral farming. Our largest consumer, Fonterra (30 MW instantaneous demand), operates a milk processing factory at Clandeboye, which supports economic activity in the area.

The other larger urban area is Geraldine, a township with a population of 2,700. Geraldine benefits from the passing of tourists through the inland scenic route.

Security of Supply

The SoS of Temuka GXP and its associated regional zone substations are outlined in the following table.

Zone sub/ load centre	Actual	Target	Comment
Temuka GXP	N-1	N-1	Solid N-1 security eroded in 2015. Security is currently being maintained via Transpower. GXP capacity upgrade is yet to be confirmed.
Temuka	N-1	N-1	Security target is met for this planning period in accordance with our SoSS.
Clandeboye 1	N-1	N-1	Security target is met for this planning period in accordance with our SoSS. Target may be breached if decarbonisation plans are confirmed, at which time options will be investigated to improve security to target level.
Clandeboye 2	N-1	N-1	Security target is met for this planning period in accordance with our SoSS. Target will be breached if Fonterra chooses to decarbonise with electric boilers, at which time options will be investigated to improve security to target level.
Geraldine	N	N-0.5 SW	Project option analysis is underway to explore security improvements.
Rangitata	N-1 SW	N-1	Rangitata is currently on N-1 for loads under 10 MW, options assessment is underway to improve security to 15MVA.

Temuka demand forecast

The demand forecasts for the Temuka GXP are shown below.

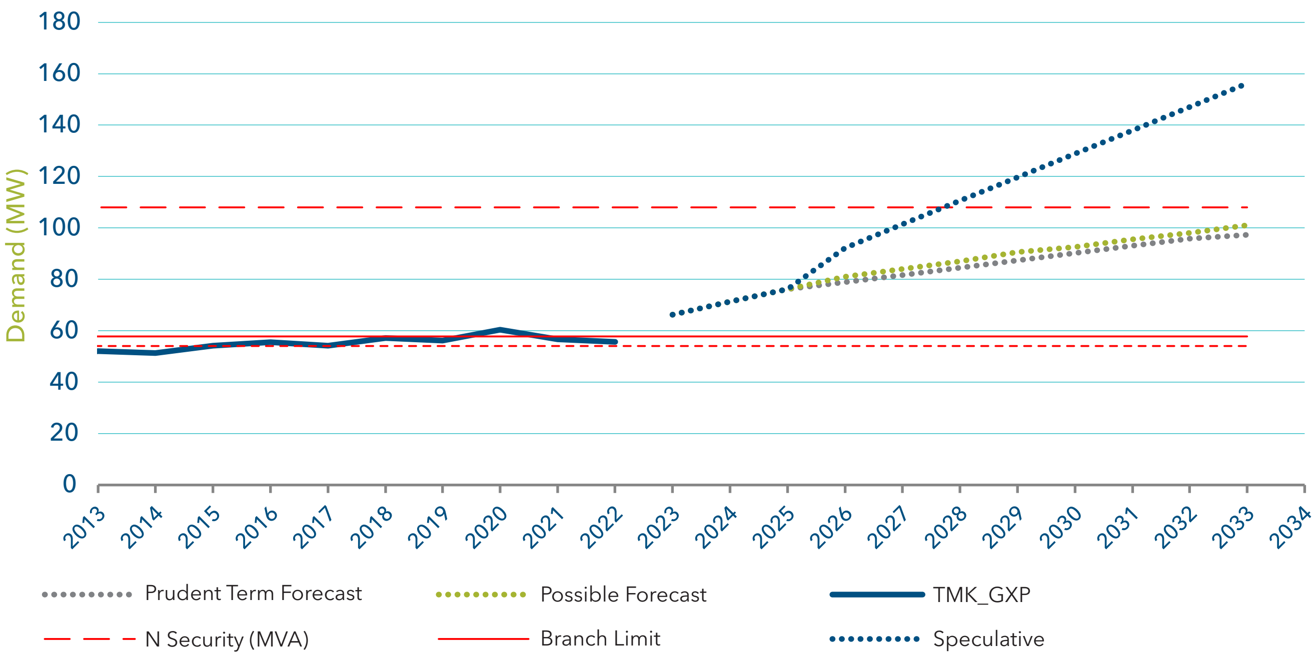


Figure 18: Temuka GXP Demand Forecast.

Existing and forecast constraints

New Orari GXP substation

The Temuka GXP may be overloaded if enquiries for decarbonisation and DG developments proceed. A new GXP at Orari would be the most economical solution to deal with future developments in the Temuka GXP area.

Two 110kV lines would then be built between this new Orari GXP and Clandeboye, where a new zone substation would convert the 110kV to 33kV. The new substation would offload Fonterra Clandeboye from the Temuka GXP. Either two 110kV lines or additional 33kV lines would also be built between the new Clandeboye substation and Temuka GXP.

We have also received enquiries for DG in the Clandeboye area.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		New GXP Orari substation		
Prudent	Possible Load Growth (Highly dependent on industrial load growth, decarbonisation and distributed generation).	Prepare for a new GXP substation at Orari.	2028	0.6M
Speculative		Build a new GXP.	2030	Transpower
Speculative		Install 2x 110/33kV power transformers.	2030	Transpower
Speculative		Build 2x 110kV lines (15km each).	2031	Customer funded
Speculative		Build 2x 33kV circuits to Geraldine (6km each).	2034	1.1M
Speculative		Build 2x 33kV circuits to Rangitata (7km each).	2034	1.3M

New Milford/Clandeboye Substation

In the Temuka region, peak demand occurs during summer, based on the predominant dairy and irrigation load. The Fonterra Clandeboye load is increasing with plans for more processing capacity and decarbonisation. With this potential significant increased load on the Temuka GXP, the GXP is no longer able to supply power at the current SoS and Transpower has been commissioned for a concept design report to upgrade the Temuka GXP. This is to be run in parallel with the Orari GXP proposal. Due to the speculative nature of this potential load growth has not been forecast in the load graph below. Only prudent load growth is shown currently.

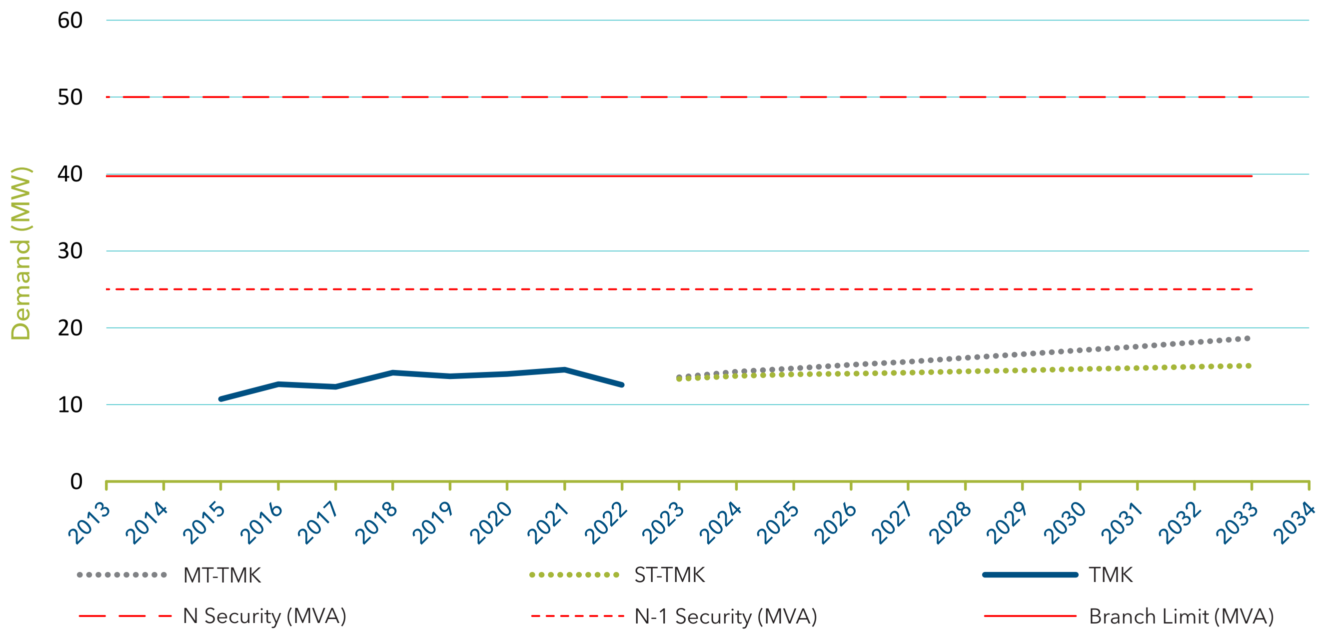


Figure 19: Temuka Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
Milford/Clandeboye Substation				
Speculative	Possible load growth. (Highly dependent on industrial load growth, decarbonisation and distributed generation).	Prepared for a new substation in the Milford/ Clandeboye area.	2031	Customer funded
Speculative		Relocate the Temuka ripple plant to this site at 33kV.	2031	0.6M
Speculative		Install a Battery Energy Storage System (BESS) (5MVA at 2.5 MW/h). Install a BESS (5MVA at 2.5 MW/h).	2031	3.0M
Speculative		Facilitate the connection of DG at 33kV.	2031	0.4M
Temuka GXP				
Speculative	Possible load growth (dependent on industrial load growth, decarbonisation and distributed generation.	Connect Temuka to the new Orari GXP.	2033	To be determined

New Clandeboye Substation

Future developments at Fonterra Clandeboye may necessitate building a third Clandeboye Zone Substation.

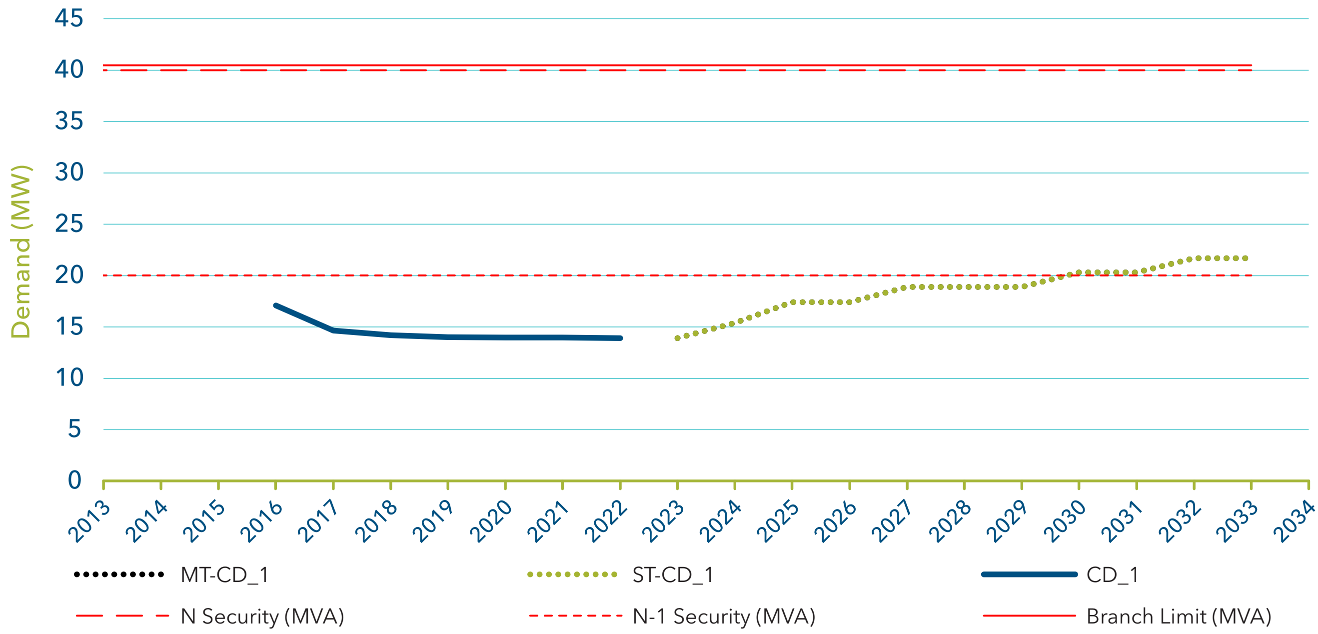


Figure 20: Clandeboye 1 Zone Substation Demand Forecast.

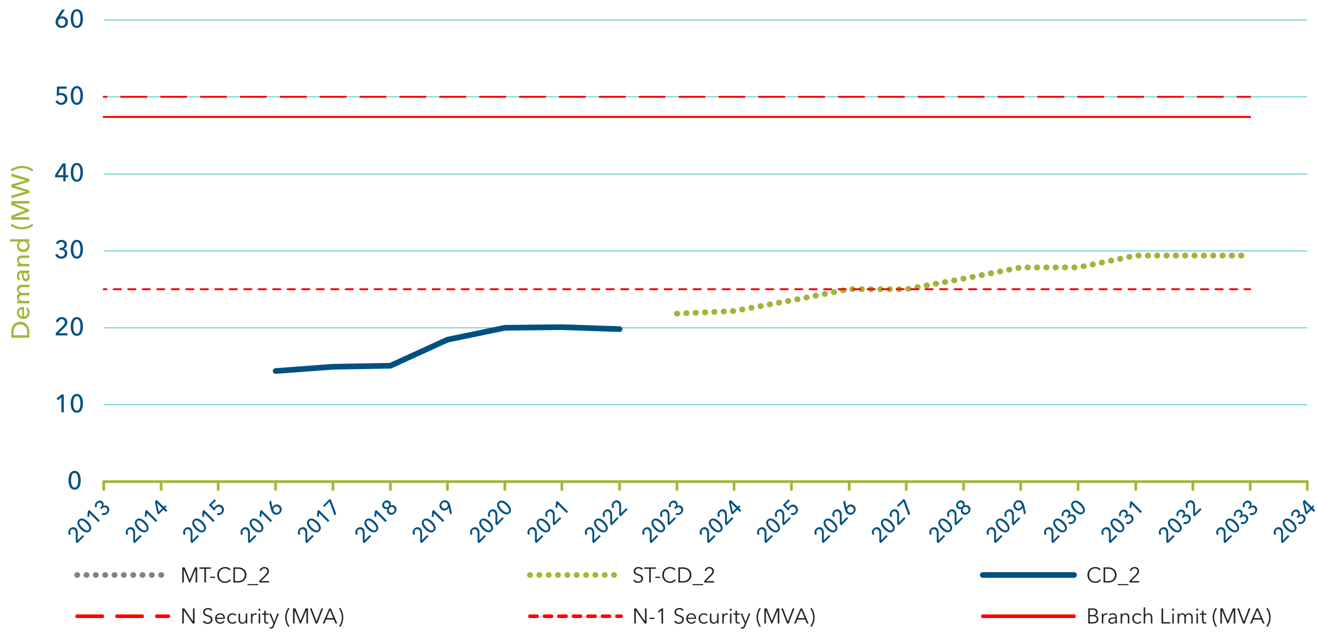


Figure 21: Clandeboye 2 Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
New Clandeboye 3 Zone Substation				
Speculative	Possible load growth. (Highly dependent on industrial load growth and/or decarbonisation).	Build a new substation.	2031	Customer funded
Speculative		Install 2x 33/11kV power transformers.	2031	
Speculative		Establish a 33kV bus.	2031	
Speculative		Establish an 11kV bus.	2031	

New Twin Geraldine Substation

To improve our resilience and N-1 supply security, we also plan to build a second substation in Geraldine and connect this substation to Orari. Based on current planning demand forecasts this improvement will be outside the 10-year planning period and its investment is speculative. The Orari GXP solution could see the Rangitata Zone Substation connected via two feeders, and the existing Geraldine Zone Substation also connected via two feeders.

Figure 22: Geraldine Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
New Geraldine Twin Zone Substation				
Prudent	Likely N-1 supply security.	Prepare for a twin zone substation in the Geraldine area.	2028	1.5M
Speculative		Build a new substation.	2033	5.0M
Speculative		Connect to the existing 11kV network within Geraldine.	2034	0.3M

For the Temuka rural area, there is limited backup from Geraldine, Rangitata, Pleasant Point, and Timaru Zone Substations. Backup capacity is being eroded due to a steady load growth. A detailed engineering investigation will be undertaken during 2023/24 to establish options to ensure we will continue to meet our security standards.

The LV (230/400 V) reticulation in urban areas of Temuka and Geraldine are starting to show challenges regarding voltage levels. Information is starting to surface that the voltage levels are on the high side. This can cause problems for DG, in particular solar panels. This is also a challenge for the many hut communities in the area. During this planning period we will commence a project to determine the extent of the challenges in this area and identify resolution options. In the meantime, the hut community reticulation has been added as a congested area for DG and published on our website in accordance with Part 6 of the Code.

Albury GXP (ABY)

Overview

The Albury Region is mainly rural with farming the predominant activity. The rural service town of Fairlie is located in the Albury GXP region and also services tourist who are travelling the South Island inland scenic route.

Lake Opuha is located near Fairlie, supplying the Opuha irrigation scheme. The scheme also owns and operates a 7MW hydropower generation scheme embedded in our network injecting power at 33kV.

Security of Supply

The following table outlines Albury and Fairlie Substations' SoSS.

Zone sub/ load centre	Actual	Target	Comment
Albury	N	N	Security target is met for this planning period in accordance with our SoSS. A Transpower mobile substation can be deployed at this GXP. Transpower has evaluated this GXP as 'Low Economic Consequence' and hence does not have a target of providing a higher security for it during this planning period.
Albury-Fairlie	N	N	Security target is met for this planning period in accordance with our SoSS.
Fairlie-Opuha	N	N	Security target is met for this planning period in accordance with our SoSS.
Albury	N	N	Security target is met for this planning period in accordance with our SoSS.
Fairlie	N	N-0.5 SW	Limited fault backup to Fairlie Zone Substation and distribution feeders. Fairlie has a mobile generator port that can be utilised during outages. An investigation into increasing the limited distribution feeders' backup will be initiated and prioritised in accordance with our project prioritisation methodology.

Albury Demand forecast

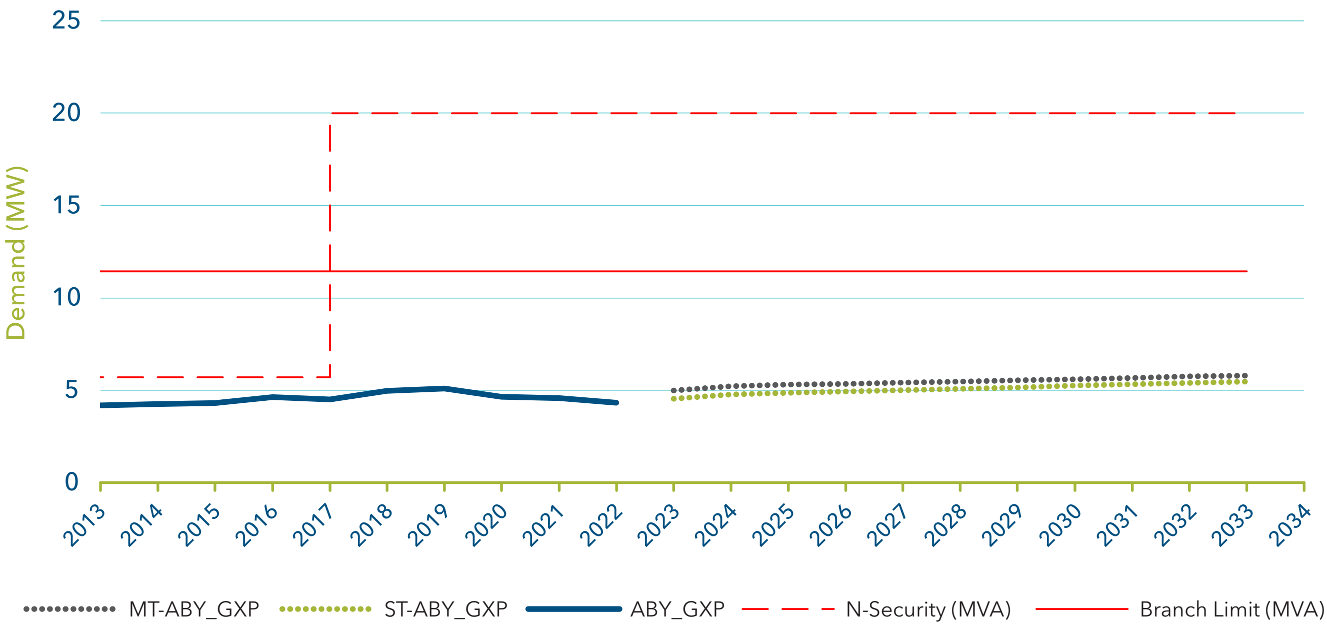


Figure 23: Albury GXP Demand Forecast.

Existing and forecast constraints

Albury Zone Substation upgrade

Albury GXP is limited by Transpower's 110kV transmission lines and would potentially need to be upgraded if a significant high-voltage connection was realised. We may need to create a 33kV bus to accommodate future DG developments within the area. In the future we may also consider connecting Albury GXP with an overhead feeder. This would provide us with an alternative supply to Pleasant Point in support of the Timaru GXP. These developments are currently considered to be speculative but will be considered as part of our long-term future network plans.

Figure 24: Albury Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Albury Zone Substation		
Speculative	Possible large-scale DG developments.	Convert the exiting power transformer to 110/33kV.	2028	Customer funded
Speculative		Build a new 33kV bus.	2028	
Speculative		Tie for DG at 33kV.	2028	
Speculative		Tie for BESS at 33kV.	2028	
Speculative	Possible load growth.	New 33kV overhead line to Pleasant Point.	2034	2.7M

Fairlie Zone Substation upgrade

The reliability of the Fairlie Zone Substation can be improved by installing an indoor 11kV circuit breaker bus. We could also improve our resilience by building a new 33kV bus for the Opuha Generator at Fairlie Zone Substation. This would allow Opuha Generator to supply our Fairlie substation load during planned outages at Albury GXP. In addition, it would improve our ability to manage emergency situations and adapt to climate change-related outages at Albury GXP, as the Opuha Generator could serve as a backup power source for Fairlie.

Figure 25: Fairlie Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Fairlie Zone Substation		
Possible	Possible reliability.	New 33kV bus (for Fairlie Substation, Opuha Generator and Alpine Mobile Substation connection).	2031	0.4M
Possible		Change 11kV RMU bus configuration to indoor 11kV bus by 2027.	2031	1.5M

We have received interest for a DG connection within the Albury area. We have not received any information of the likely timeframe for the construction, but if generation is realised, it would potentially increase our ability to respond to any demand increase if paired to an energy storage solution and the demand was matched.

In 2017, Transpower installed a 110/33/11kV transformer, which we forecast will provide capacity for the current planning period and beyond. The transformer's secondary connection is arranged so that it can be reconnected for use at 33kV in the future.

The Albury rural area has limited backup from adjacent 11kV distribution feeders from Fairlie, Pleasant Point, and Temuka. Due to distance involved, this results in voltage constraints.

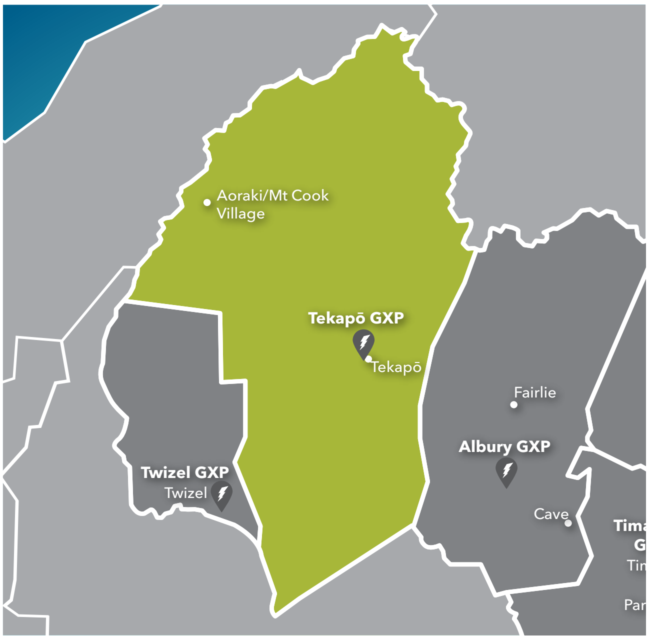
There is limited capacity available to Burkes Pass. If added capacity is required, the most likely solution would be a 'microgrid' or a full rebuild of the overhead line from Fairlie.

Tekapō GXP (TKA)

Overview

The Tekapō GXP region is within the Mackenzie District that is situated 40km west of Timaru and extends to the main divide. The Mackenzie District is an alpine area, requiring assets to be designed for snow and wind loadings.

Tekapō is a tourist and domestic holiday destination with growing subdivision and hotel developments. Aoraki/Mount Cook National Park, including Aoraki/Mount Cook village, are popular tourist destinations within the district. Genesis Energy has generation assets at Lake Tekapō and Lake Pukaki.



Security of Supply

The Tekapō, Haldon-Lilybank, Old Man Range and Unwin Hut substation security of supplies are outlined in the following table:

Zone sub/load centre	Actual	Target	Comment
Tekapō	N	N-1	The GXP's target is N-1 in accordance with our SoSS due to its high growth rate and criticality being a popular tourism destination. Transpower do not have a target of providing a higher security during this planning period because a 28MVA generator can provide black start support at 11kV. We engaged in discussions with Transpower to examine the viability of enhancing the security at the 33kV supply level. Transpower will implement a closed 33kV bus for improved security once their Outdoor to Indoor conversion (ODID) is finished. The timing of this is not yet known.
Tekapō-Tekapō Zone Substation	N	N-1	N-1 is the desired security level for this sub-transmission circuit up to the Tekapō Zone Substation, hence options will need to be assessed to increase the sub-transmission line security to provide that level of security.

Zone sub/load centre	Actual	Target	Comment
Tekapō Zone Substation	N	N-1	N-1 is the desired security level for Tekapō Zone Substation. For this, the options are either to install a second transformer at the existing zone substation or a new zone substation at a different location. This will be in conjunction with increasing the existing Tekapō Zone Substation capacity.
Haldon-Lilybank	N	N	Security target is met for this planning period in accordance with our SoSS.
Old Man Range	N	N	Security target is met for this planning period in accordance with our SoSS.
Unwin Hut	N	N	Security target is met for this planning period in accordance with our SoSS.

Tekapō Demand Forecast

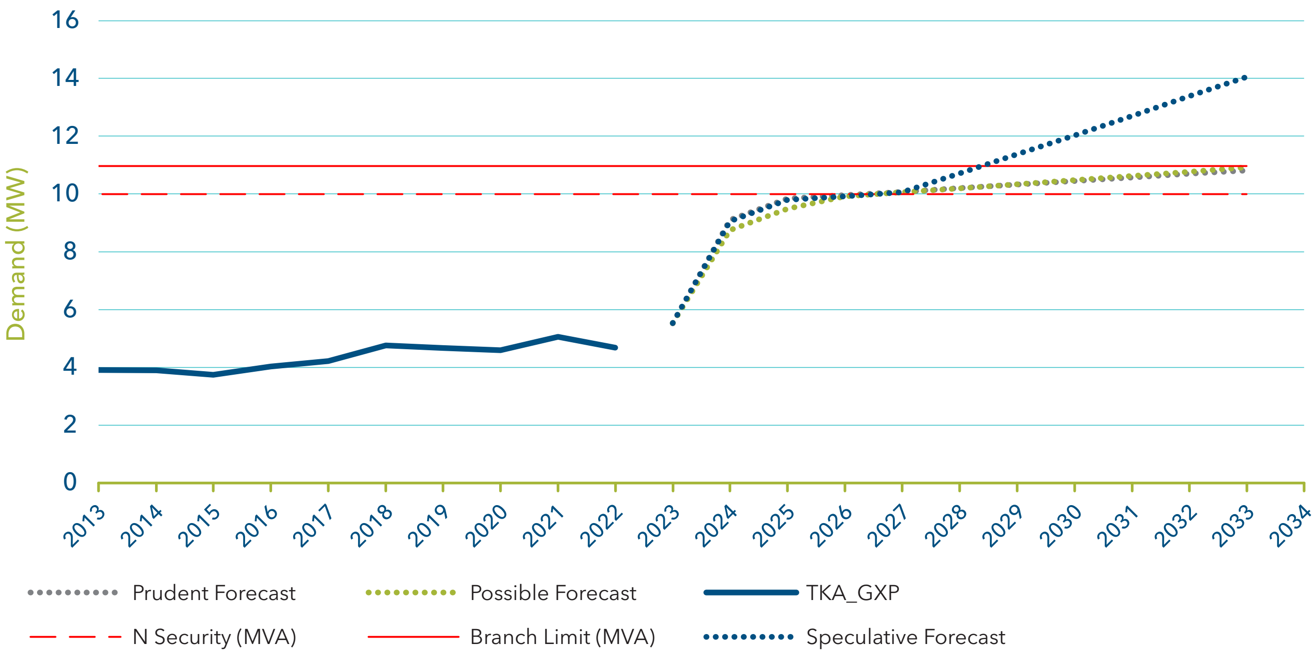


Figure 26: Tekapō GXP Demand Forecast.

Existing and forecast constraints

There is significant projected load growth in the Tekapō area, mainly due to new retail developments and subdivisions in the Tekapō town.

Tekapō Twin Zone Substation

The predicted load growth within the Tekapō GXP area was delayed, in part due to the Covid pandemic, but, if realised, would exceed our N-1 supply security limit. We will continue to monitor growth in the area, and if required we would build a second Tekapō Zone Substation and distribute the load between the (then) two Tekapō Zone Substations. We would connect the twin Tekapō Zone Substation with the Tekapō GXP and build a 33kV sub-transmission circuit between the existing Tekapō substation and the new twin substation. We would need to build a new 33kV bus at the existing Tekapō substation. This bus would allow us to build a 33kV sub-transmission tie to Twizel. We may also have to connect potential DG to the 33kV bus at the Tekapō substation.

We would connect the two substations with 11kV two feeders. We would distribute the existing 11kV load between the two substations and form an 11kV ring between the substations and Tekapō town.

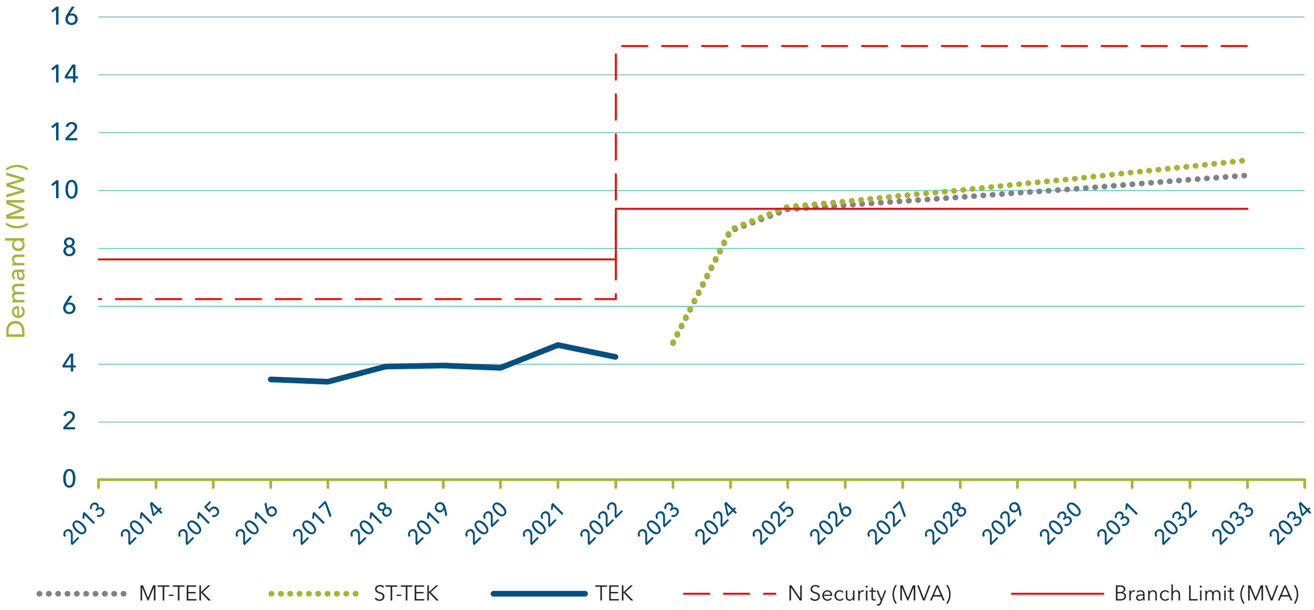


Figure 27: Tekapō Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Tekapō Zone Substation		
Possible	Possible load growth.	Build a second sub-transmission circuit to the Tekapō Substation (33kV, 30MVA).	2028	0.6M
Possible	Possible N-1 supply security.	Install a second power transformer at Tekapō GXP (30MVA, 110/11kV).	2028	Transpower
Speculative	Unlikely N-1 supply security.	Install a BESS (5MVA at 2.5 MW/h).	2028	Customer funded
Possible	Possible load growth.	Build a second sub-transmission circuit to the Tekapō Substation (33kV, 30MVA)	2028	Customer funded
		New Twin Zone Substation		
Prudent	Almost certain load growth.	Secure site for a substation.	2025	0.2M
Possible	Possible load growth.	Build a second Twin Substation.	2029	3.0M
Possible		Install a feeder cable between Tekapō GXP and the Twin Substation. Tie the 11kV distribution system between the Tekapō Substation and the new Twin Substation.	2029	1.6M
Possible	Possible N-1 Supply Security.	Close the 11kV rings between the Tekapō Substation, the new Twin Substation and Tekapō.	2030	1.6M

Unwin Hut upgrade

The expected growth in EVs at Aoraki/Mt Cook village may necessitate an upgrade to Unwin Hut Zone Substation.

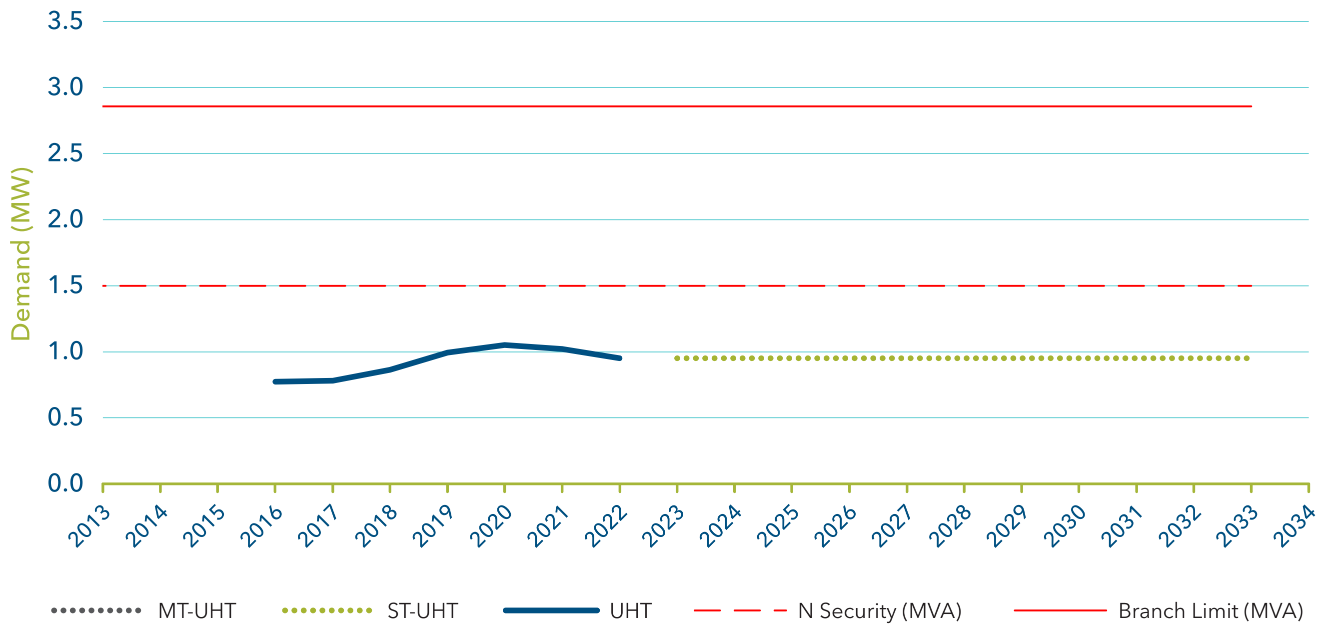


Figure 28: Unwin Hut Zone Substation Demand Forecast.

Old Man Range upgrade

We may be required to upgrade the Old Man Range substation due to load growth due to transport electrification.

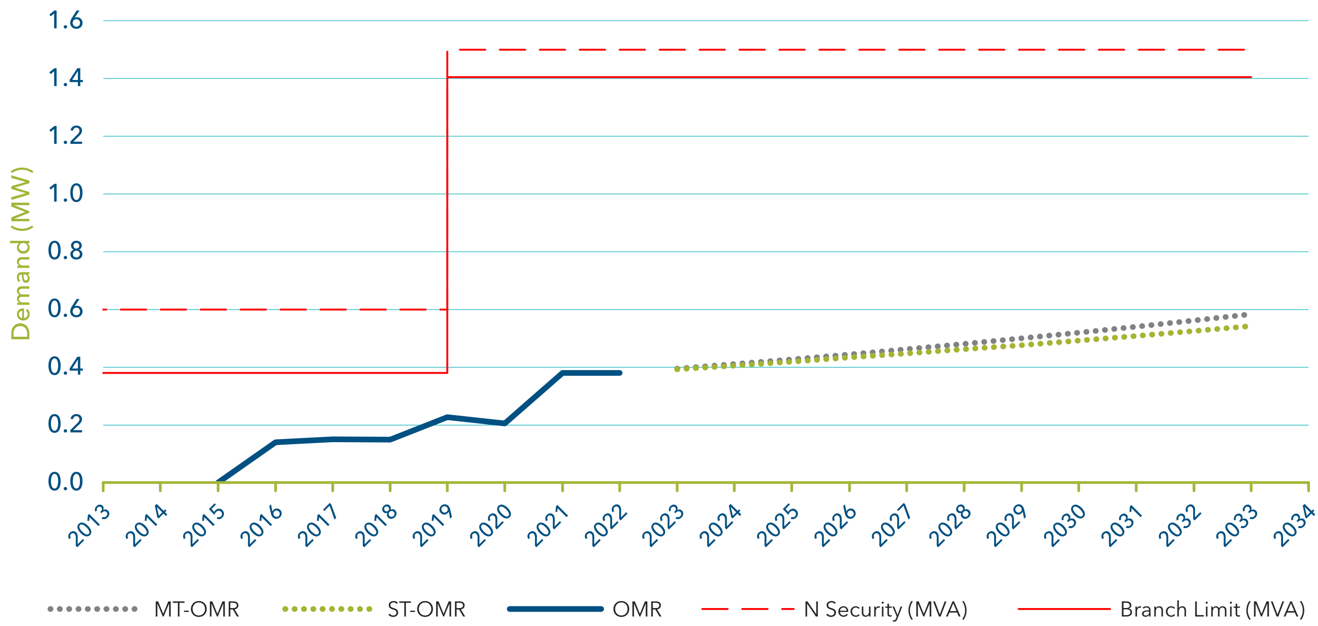


Figure 29: Old Man Range Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Old Man Range substation		
Speculative	Possible load growth.	Upgrade/replace the overhead line to Old Man Range (33kV, >6MVA).	2033	0.9M
Speculative		Transition Old Man Range to 33/22kV autotransformer (3MVA).	2033	0.5M

Haldon-Lilybank Substation

Load constraints on the Haldon-Lilybank line would be addressed by converting the two-phase line to a three-phase line. We would then transition the feed to the line from 11kV to 33kV and upgrade the Haldon-Lilybank autotransformer to 33/22kV. This is currently within the speculative investment criteria.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Haldon-Lilybank Substation		
Speculative	Likely load growth.	Install 22kV bus setup at Haldon-Lilybank and then upgrade all the two phases to three phases in a systematic approach.	2028	To be determined
Speculative	Possible load growth.	Upgrade/replace the overhead line to Haldon-Lilybank (33kV, >6MVA).	2031	1.5M
Speculative		Transition Haldon-Lilybank to 33/22kV autotransformer (3MVA).	2032	2.5M

Enquiries for DG in the Tekapō area has been received but no information of the likely timeframe for the construction is available at the time of publishing our AMP.

Twizel GXP (TWZ)

Overview

Twizel is an expanding town that is popular as a holiday and tourism centre. It also serves as a service centre in the Mackenzie District supporting agriculture, aquaculture, manufacturing and engineering works, and as a regional base for Meridian Energy and the Department of Conservation.

Meridian Energy has generation assets at Lake Ohau, Lake Ruataniwha, and Lake Benmore in the region

Twizel demand forecast

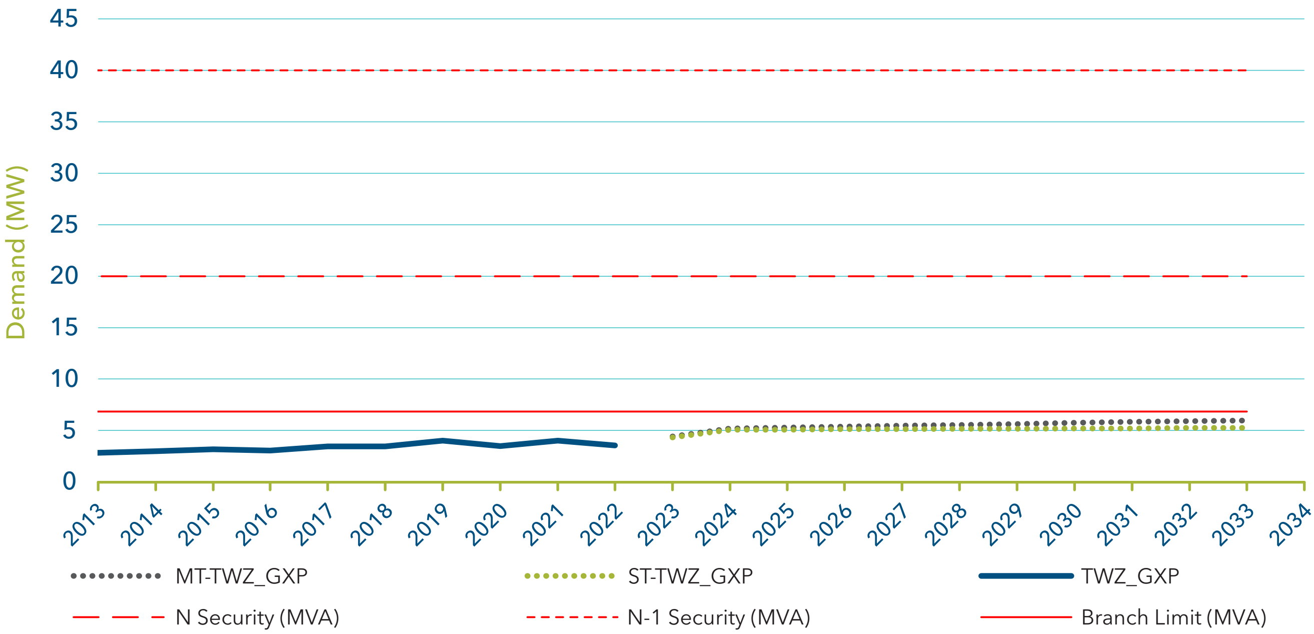


Figure 30: Twizel GXP Demand Forecast.

Security of Supply

The following table outlines the Twizel region's SoS.

Zone sub/ load centre	Actual	Target	Comment
Twizel	N-1 SW	N-1	The 33kV bus is running open, providing supply from a single transformer. A request has been submitted to Transpower to investigate the feasibility of running the 33kV bus closed providing N-1 supply to Twizel Village Zone Substation as part of their ODID project. The request also includes considering the costs of providing a second 33kV point of supply (from bus B). Transpower has evaluated this GXP as of 'High Economic Consequence'.
Twizel-Twizel Village Zone Substation	N	N-1	Our SoSS specifies the need for N-1 security up to the Twizel Village Substation to ensure sustainable supply to match its growing criticality.
Twizel Village Zone Substation	N-0.5 SW	N-1 SW	Our SoSS specifies N-1 switched security for this substation. Given that the substation has reached the end of its operational life, the upgrade project currently underway aims to improve the SoS at the power transformer level.

Existing and forecast constraints

With a single 33kV overhead line supplying the Twizel Zone Substation, the SoS is N security. Our SoSS does require N security. For N-1 SoS at the Twizel Zone Substation would be addressed by building a second sub-transmission circuit (cable) between Twizel GXP and Twizel Village Zone Substation. We would also build a second substation in Twizel so that we can distribute the load between the two zone substations and create rings between the two zone substations.

As the Twizel Village Zone Substation is near its end of life, the replacement project will also include an improvement to the SoS at the power transformer level.

The ripple injection plant at the Twizel GXP is used by Network Waitaki. Currently, all ripple relays in the area are controlled via its time clock function. Future ripple injection plant development will be based on an economic analysis. With the introduction of smart meters, there may be alternative ways to provide demand side management.

Figure 31: Twizel Village Zone Substation Demand Forecast.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Twizel Substation		
Possible	Possible load control.	Install new ripple plant.	2029	0.5M
Speculative	Unlikely N-1 supply Security.	Install second sub-transmission circuit cable between Twizel GXP and Twizel substation (>30MVA, 2km).	2031	1.5M
		Twizel Twin Substation		
Prudent	Likely N-1 supply security.	Prepare for a second transformer in Twizel.	2029	0.5M
Prudent		Build new substation.	2034	3.5M
Speculative	Unlikely N-1 supply security.	Install 33kV cable between Twizel GXP and the new twin substation (5km).	2034	2.2M
Speculative		Move the 11kV load from Twizel Substation to the new substation.	2034	0.6M

Procuring a new mobile substation, and housing this mobile substation in Twizel, would allow us to maintain the Twizel Zone Substation better.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Twizel Mobile Substation		
Prudent	Likely reliability.	Procure a 33/11kV mobile substation and house this mobile substation in Twizel.	2029	2.0M

We have received an initial DG application the Twizel area.

Resilience and supply security options

As our network matures and expands, we may incur additional expenses to enhance our network, boost its reliability, and strengthen its resilience. At present, we do not allocate funds for these system growth, reliability, and supply security projects due to financial constraints. These projects are included in the "possible" forecast, as we may opt to undertake this work, if circumstances necessitate it, and move it to the "prudent" scenario.

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
		Asset Replacement and Renewal		
Possible	Possible N-1 supply security.	Twizel North-West Arch Upgrade provide an alternative feed to Glen Lyon Road and improves the link between feeders.	2025	2.5M
Possible	Possible N-1 supply security.	Twizel Ohua to Ostler Link upgrade improves the feeder ties between feeders Z1 and Z2 and removes piggyback connections.	2026	4.5M
Possible	Possible N-1 supply security.	Remove Karl Pfister (KP) joints in Williamson place, Geraldine, as KP joints bypass our need for Distribution Boxes (DBs) along our cable routes. When KP joints were used, we didn't have DBs.	2028	0.12M
Possible	Possible quality of supply.	Upgrade Voltage Regulator A1428 near Waimate.	2031	0.36M
Possible	Possible Quality of Supply.	Upgrade Voltage Regulator A1144, near Makikihi, to 300A.	2028	0.36M
Possible	Possible Reliability.	Timaru Protection Replacements: Replace Timaru relays based on age.	2025	0.42M
Possible	Possible Reliability.	Clandeboye 1 Protection Replacements: Replace Clandeboye 1 relays based on age.	2026	0.5M
Possible	Possible Reliability.	Clandeboye 2 Protection Replacements: Replace Clandeboye 2 relays based on age.	2027	0.5M
Possible	Possible Reliability.	Pleasant Point Protection Replacements: Replace Pleasant Point relays based on age.	2028	0.3M
Possible	Possible Reliability.	Studholme Protection Replacements: Replace Studholme relays based on age.	2028	0.45 M
Possible	Possible Reliability.	Temuka Protection Replacements: Replace Temuka relays based on age.	2029	0.6M

Scenario	Drivers	Project	Timing (FY)	Estimate ($)
Possible	Possible Reliability.	Pareora Substation Protection Replacements: Replace Pareora Substation relays based on age	2030	0.45M
Possible	Possible Reliability.	Geraldine Protection Replacements: Replace Geraldine relays based on age	2031	0.3M
Possible	Possible Supply Security.	Build alternate 33kV circuit from Geraldine to Rangitata-T1.	2026	1.6M
Possible	Possible Supply Security.	Build a dedicated line from Temuka GXP to Canal Road Substation, providing a separate supply to Rangitata-T1.	2026	1.2M
Possible	Possible Reliability.	Replace aged Twizel Village power transformer.	2027	1.5M
Possible	Possible Reliability.	Replace aged Unwin Hut power transformer	2029	1.5M
Possible	Possible Reliability.	Replace aged Twizel Village power transformer.	2030	1.5M
Possible	Possible Reliability.	Replace aged Fairlie Zone power transformer.	2031	1.5M

08. **Managing our network**

Managing our network

Our core purpose remains delivering secure, reliable and sustainable electricity to our customers. This means we must continue to manage our existing assets and infrastructure, ensuring strategic alignment with our future direction.

In this section, we elaborate on our asset lifecycle management approach across our network. We provide an in-depth account of this approach and how it will aid us in achieving our asset management objectives over the planning period.

We also cover various aspects of our network-wide operations, including network control, system outages and emergencies, maintenance, vegetation management, and our methodology for forecasting capital expenditure projections. We also discuss our asset fleets and potential future opportunities.

Overview

Our fleet management approach encompasses the following five lifecycle stages:

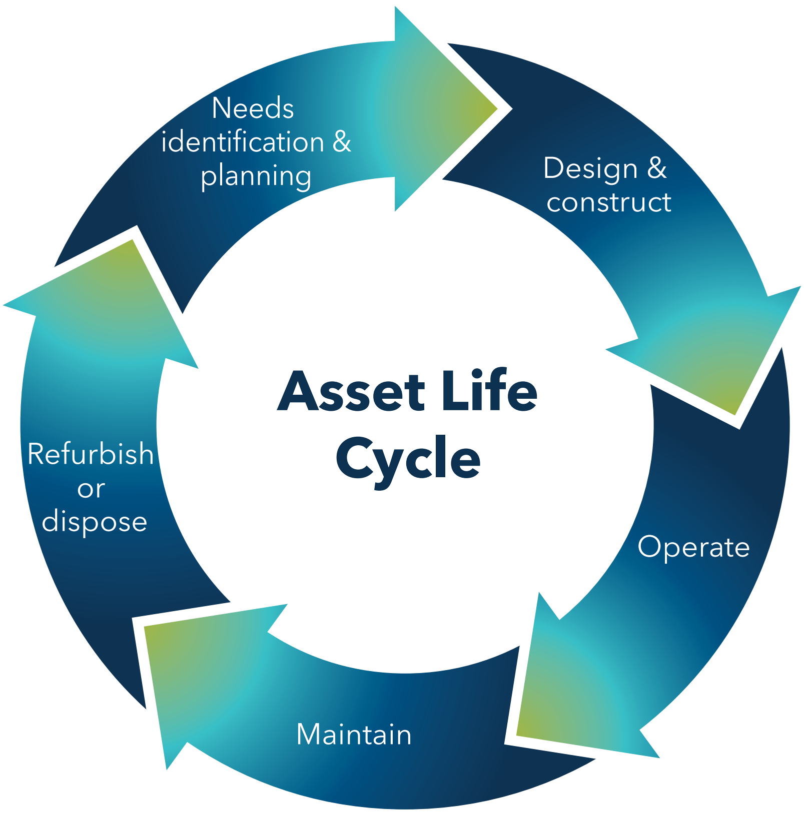


Figure 1: Asset management lifecycle.

Our fleet strategies inform our daily asset management practices. These strategies are continually reviewed to ensure that they aligned with our asset information, technology changes, and support our long-term asset lifecycle goals.

Network-wide operations

This section sets our approach to operating and maintaining our network assets. It describes our maintenance activities and sets out our forecast network OPEX for the planning period.

Network control

The primary role of network control is to ensure a continuous supply of electricity to our customers and to maintain the network in a safe condition 24 hours a day, seven days a week.

Control centre

In our Control Centre, network controllers monitor our network status and load in real-time and take appropriate actions, including planned and unplanned switching, to make sections of the network available for maintenance or repairs. They also manage the controllable load on our network to comply with retailer contracts with customers and manage peak loading on our network. We manage both the HV and LV networks through our Control Centre.

The Control Centre also performs the dispatch function, communicating with customers and our contractors to dispatch field staff to where work is necessary to maintain or restore electricity supply. This team also works closely with the rural fire service in South Canterbury by disabling auto-reclose functions on our pole-mounted reclosers when conditions are dry and there is a fire risk.

Supervisory control and data acquisition

Our SCADA system is one of the primary tools used by the Control Centre to monitor our network's status, loading and performance. This includes the loading, currents and voltages at key locations, the position status (open/closed) of circuit breakers (CBs), switches and reclosers, and the status of a wide range of alarms, such as "power transformer oil temperature".

The SCADA system is also used to perform load control functions and remotely operate CBs and switches across the network. All these network control points are connected to our SCADA master station through telecommunications links. It is therefore imperative that our communications infrastructure is fit for purpose and has the necessary scalability to support increased use of automation and real-time monitoring.

Our SCADA system is developed and maintained by our inhouse SCADA specialists.

The SCADA system is managed as part of our secondary systems portfolio and is further discussed in SCADA and communication systems later in this section.

Outage management

Our network controllers handle outage-related calls and liaise directly with customers. They also manage outage restoration efforts, including tracking customer interruptions and update relevant outage information on our website and on an interactive voice recording system. Section 4 details our notification processes for planned and unplanned interruptions.

Future opportunities

To improve our network control we have identified opportunities for operational systems development. These include:

- Remote controlling of more field devices to improve operational responsiveness. These include more reclosers, remote control voltage regulation devices and remote telemetry fault passage indicators
- Expanding the use of additional SCADA features, which include electronic switching preparation, field mobility, and automatic load restoration
- Integration of SCADA with GIS and other ERP/CRM platforms

Release planning

Release planning is also managed by our Control Centre. It is the process of isolating and releasing sections of the network to enable work to be carried out safely. Release requests are processed and coordinated to minimise outage frequencies and durations.

Switching

Switching is carried out to disconnect sections of the network for safety isolation, to enable maintenance work or new connection work to be undertaken, or to restore the electricity supply in the event of a network fault. There are two principal switching methods. Remote switching is done by the Control Centre via SCADA, and field switching is carried out by our contractor under the direction of the Control Centre. Switching plans are prepared and written in the Control Centre and then distributed to the contractor. All our major zone substations and approximately 75% of our reclosers are remotely controllable.

Project: Communications System Upgrade

The planned upgrading of our communications systems during this AMP period will allow us to control more devices in the Mackenzie basin and around Fairlie.

System interruptions and emergencies

The System Interruption and Emergencies (SIE) activities entail reactive interventions in response to unplanned network events.

The main types of activities are as follows:

- **First response:** this involves the attendance of a fault person to assess the cause of an interruption, potential loss of supply, or safety risk. They evaluate the cause of the fault and may undertake switching or cut away a section of line to make it safe or to alleviate the imminent risk of a network outage
- **Fault restoration:** this is undertaken by the fault person and includes switching, fuse replacement, or minor component repair to restore the electricity supply
- **Second response:** this is where an initial fault response has restored the electricity supply, but additional resources or equipment is required to restore the network to its normal state

SIE work is prioritised and dispatched by the Control Centre, with the physical work carried out by our contractors. There is limited proactive planning possible for SIE work other than ensuring sufficient resources are on standby to respond to network faults. This is achieved through a specified agreement with our service provider NETcon. Failure to respond to SIE promptly adversely affects the service provided to our customers and may pose risks to public safety.

Our service agreement with NETcon requires the provision of sufficient resources for fault response. These are dispatched based on criteria, such as potential safety risks, the need to maintain service levels for customers, and consistently meet contractual response times.

Various factors, including asset condition, weather, environmental conditions, and our protection philosophies, drive SIE work volume.

The high-level objectives for our SIE portfolio are detailed below.

Asset management objective	Portfolio objective
Safety & environment	Reduce fault response time to reduce the potential risk to public safety. Reduce safety hazards by prioritising safety-driven faults. Ensure that a safety power supply meets our customers' electricity needs.
Customer service levels	Minimise outage events and durations to support our regulatory reliability requirements. Ensure a reliable power supply effectively supports our customers' operations and businesses.
Cost	Consider using alternative technology to reduce the cost of reactive works and improve fault response times.
Community	Minimise landowner disruption when responding to network faults. Reduce fault restoration times to ensure we return the electricity supply to customers promptly.
Asset management capability	During the "Identifying needs and planning" stage of an asset's lifecycle, consider better use of asset rating information to enhance load limits for greater network back feed during faults. Support our customers' energy needs and business operations during asset failure events with alternative supply routes.

Table 1: SIE portfolio objectives.

To achieve these objectives, adhere to the following operational guidelines:

- **Health and Safety culture** – carry out field safety audits to ensure a consistent approach to safety at work
- **Public awareness** – continue to promote awareness of the risk and dangers of electricity networks by educating the public and customers through regular engagement
- **Resource management** – ensure the availability of adequate resources and equipment to undertake SIE work, with relevant spares and materials available at all times
- **Systems enhancements** – drive improvements through systems and tools available to the Control Centre, including communication systems, SCADA, and GIS. These tools help to optimise network operations management and decision-making

Our SIE expenditure forecast for the planning period is shown in Figure 2. This category of expenditure includes a contracted service for first-response fault calls. When costs relate to operating our network for capital projects, the costs are counted against the project, not SIE expenditure.

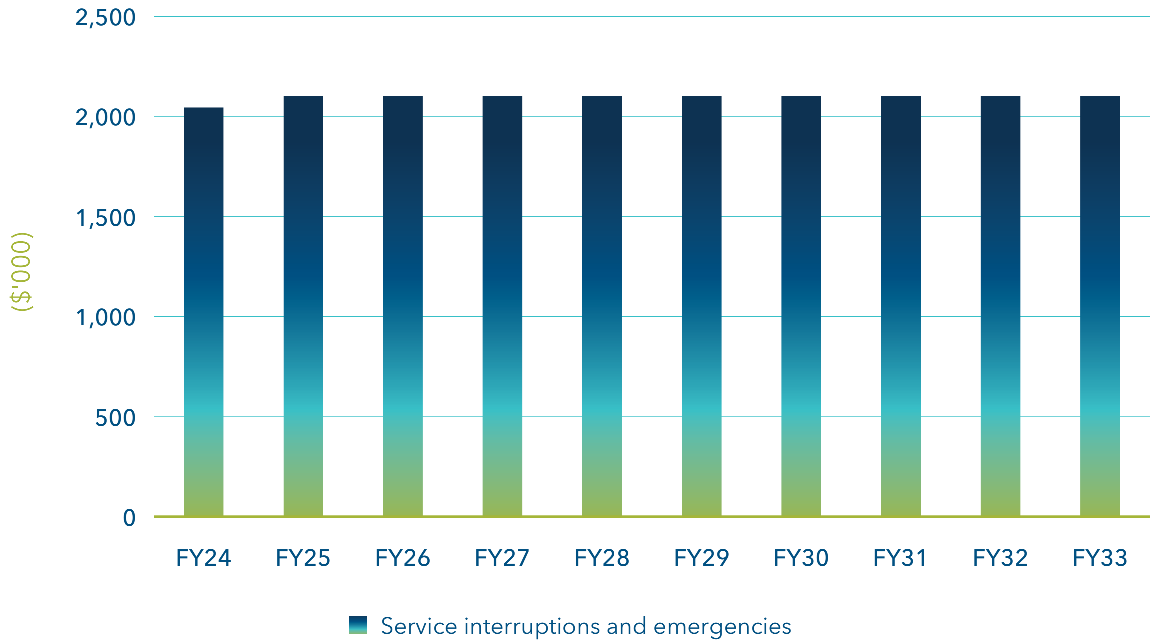


Figure 2: Forecast expenditure on SIE.

We are forecasting that expenditure on SIE activities will remain relatively stable over the next 10 years as the impact of our enhanced vegetation management programme, increased asset renewals, and increased network automation takes effect.

There is significant uncertainty around the impact of climate change-related weather events on our region and our network. In 2023/24 we will carry out a risk assessment to better inform our future SIE forecasts and support network resilience projects.

Future network-wide operations improvements

To improve our asset management approach, we have identified several opportunities for operational systems development. These opportunities will support our strategic pillar of operational excellence. The opportunities include:

- Automation of more field devices to improve operational responsiveness. These include more reclosers, remote control voltage regulation devices and remote telemetered fault passage indicators
- Embedding OMS into the daily operational routine and then identifying enhancements that further improve its usability
- Moving the switching process from the manual approach to an integrated electronic workflow. This will reduce processing time and the potential for switching errors
- Enhancing our communications network. With the introduction of digital mobile radio, we will extend our communications network coverage, improve worker safety, response times and reliability
- Enabling more informed and timely decisions and actions. Field mobility solutions will provide field staff with ease of access to asset data, including standards, technical specifications, schedules, and historical maintenance data
- Making greater use of drone technology for asset inspections as part of our planned and unplanned work

Maintenance strategy

Maintenance is the care of assets to ensure that they will provide their required capability safely and reliably during its life, from commissioning through to disposal. Maintenance can evolve as the condition and performance requirements of the assets change over time. Our maintenance activities include:

- Monitoring and managing the deterioration of an asset as it is operated over time
- Restoring the asset's condition in the case of a defect or failure
- Modifications to an asset to improve performance and reliability

We maintain our network to meet network operational and security requirements, considering safety, statutory compliance, sustainable operations, and overall cost. The needs of our customers, stakeholders, and regulators drive these requirements.

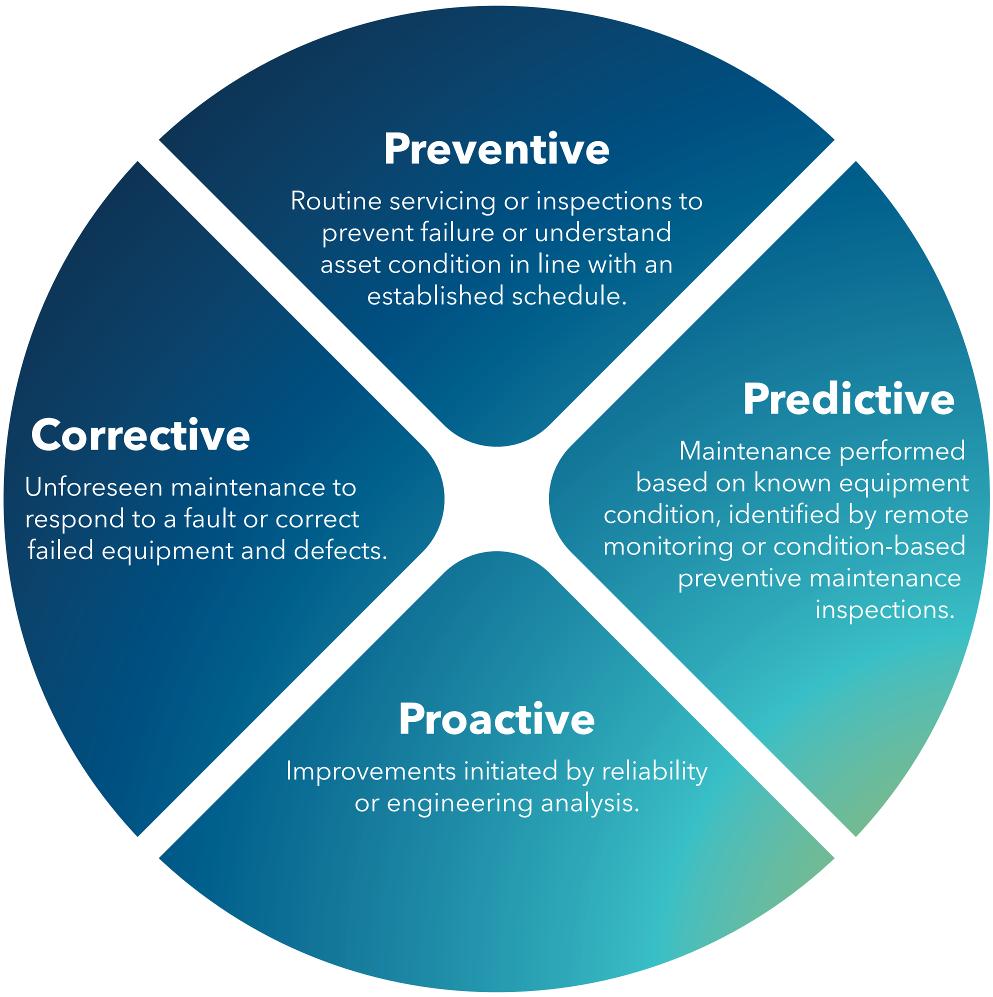
We undertake network maintenance such as:

- Routine maintenance and corrective maintenance, including condition-based inspections
- Maintenance projects to replace components of assets
- Vegetation management

Routine and corrective maintenance

Our service providers carry out routine maintenance to keep assets in an appropriate condition, ensure that they operate as required, and proactively manage failure risk. Corrective maintenance covers our response to failures and defects as these occur.

We classify routine maintenance into four work types:



The four work types are summarised below.

Preventive

Preventive maintenance is undertaken on a scheduled basis to ensure the safety and integrity of assets and compile condition information for subsequent analysis and planning. It is generally our most regular asset intervention, so is key to providing effective feedback to the overall asset management system. Preventive maintenance comprises of three activities:

- **Inspections:** checks, patrols, and testing to confirm the safety, integrity, and resilience of assets, assess fitness for service, and identify follow-up work
- **Condition assessments:** activities performed to monitor asset condition and provide systematic records for analysis
- **Servicing:** routine tasks performed on the asset to ensure the condition is maintained at an acceptable level, such as cleaning, adjustment, and lubrication

Corrective

Corrective maintenance is undertaken to restore an asset to service, make it safe or secure, prevent imminent failure or address defects. The key distinguishing feature is that the work is initiated in response to unforeseen damage, degradation, or an operational failure. Corrective work is usually identified because of a fault or during preventive inspections. Failure to undertake urgent corrective work may result in reduced network reliability. Less urgent repairs can be scheduled at the appropriate time when access, resources and parts are available.

Corrective work activities include:

- **Fault restoration:** immediate response to a fault or urgent repairs to equipment that has safety, environmental, or operational implications
- **Repairs:** unforeseen work necessary to repair the damage, prevent failure, or rapid degradation of equipment
- **Corrective inspections:** patrols or inspections used to check for public safety risks or conditions not directly related to the fault in the event of failure

Predictive

Predictive maintenance is scheduled in response to condition-based inspection and monitoring programmes. This includes activities to replace components, repair assets to correct defects and wear and tear to return the asset to a defined standard that keeps it operational and resilient. Predictive maintenance includes any additional targeted condition monitoring (such as thermo-graphic imaging) to validate an existing condition assessment or predict the likelihood of failure. Predictive maintenance helps to improve our network's resilience by proactively identifying and addressing vulnerabilities to weather-related events, such as high winds, flooding, snow, subsidence, and slipping, which are likely to increase in frequency and severity due to the impact of climate change.

Proactive

Proactive maintenance is improvement work initiated because of formal analysis and investigation by the engineering or reliability teams to reduce risk or provide an efficiency gain. Examples are asset modifications, one-off adjustments to scheduled activities, and condition monitoring programmes to provide more information or to validate findings.

Maintenance projects

Maintenance projects are a programme of work that address prevalent asset condition issues identified within routine maintenance. Maintenance projects will typically consist of programmes of small repairs or replacements of larger asset components scheduled annually, distinguishing these works from routine maintenance.

For example, a common failure mode has been identified for an asset, leading to the need to replace or repair the same component on many assets. Unlike refurbishment, which is capital expenditure, these works would not be expected to extend the useful life of the larger asset but rather restore the asset to an expected condition.

These works are typically managed as planned projects and are budgeted for and scheduled in advance. Undertaking maintenance works as a formal project rather than as many individual activities ensures the works programme is optimised and delivered more efficiently.

Maintenance activities

We group our maintenance activities into two categories:

- **Maintenance Specification** is the specification of the maintenance to be delivered, the skills and resources required, and the inventory practices to be applied. Critically, this involves analysing work history, asset, and performance data; and applying reliability processes to improve our maintenance and supply requirements. It is supported by our Engineering team, who ensure our maintenance approach considers all asset design, servicing, and compliance requirements.
- **Maintenance Delivery** is the delivery of all maintenance work by qualified staff in a controlled manner that ensures the safety of our people, customers and the public and the timely provision of all necessary materials and parts. This includes the medium-range planning and scheduling of the work programme, together with the detailed planning of our network and land access, resources, and work scope for each job, all supporting the execution of the work.

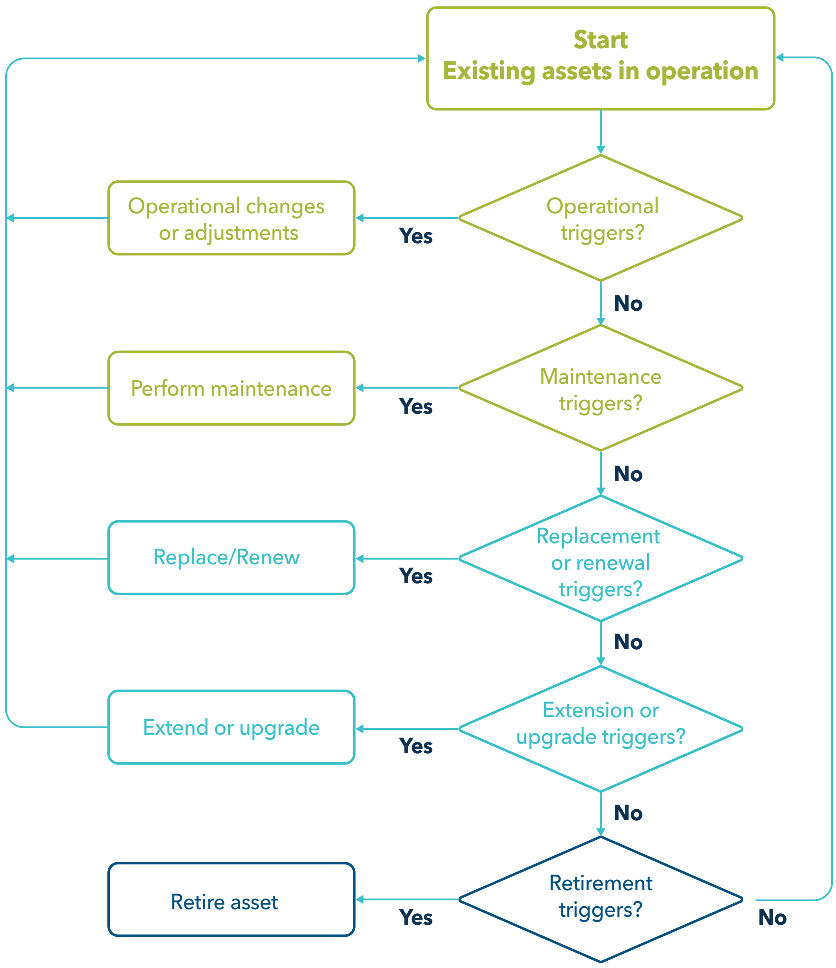


Figure 3: Maintenance lifecycle.

Maintenance Specification and Maintenance Delivery are interdependent within an improvement cycle:

- Maintenance Specification activities define our technical and quality requirements governing Maintenance Delivery
- Maintenance Delivery is the planning and execution of the work, undertaken by our service providers
- The outcomes of Maintenance Delivery (costs, equipment condition and performance, new work) are quality assessed against our Maintenance Specification activities to improve our maintenance requirements and to provide advice that will address reliability and performance risks

The high level objectives for our maintenance portfolio are shown below.

Asset management objective	Portfolio objective
Safety & environment	All work is done without risk to the public, our staff, and our contractors.
Service levels	Minimise the outage time to customers because of planned maintenance activities. Execute as much work as practicable under any single outage through appropriate planning.
Cost	Ensure cost-effective spending of budgets by reviewing the work scope against costs, the pricing of jobs before proceeding and monthly reporting of our expenses versus budgets.
Community	Inform all customers promptly of all planned outages. Minimise the disruption to traffic and general customer movements around maintenance sites.
Asset management capability	Utilise our new EAM system to capture asset condition data, implement maintenance schedules for various asset types. Use the EAM system to better schedule tasks in the same areas and on the same assets.

Table 2: Maintenance objectives.

Vegetation management

We undertake vegetation management to meet the safety obligations of our overhead lines clear of vegetation. This is to minimise vegetation-related outages in support of our reliability targets, including System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index3 (SAIFI).

The main activities undertaken in the vegetation management portfolio are:

- **Surveys:** which are periodic inspections of tree sites to determine whether trimming is required
- **Liaisons:** which are interactions with landowners to identify trees that require trimming or removal
- **Tree trimming:** which is the physical work involved in the trimming or removal of trees

Portfolio objectives

Vegetation management has a significant impact on network reliability and public safety. Prior to 2016, our network performance was adversely affected by an increasing number of interruptions caused by vegetation, as depicted in Figure 4.

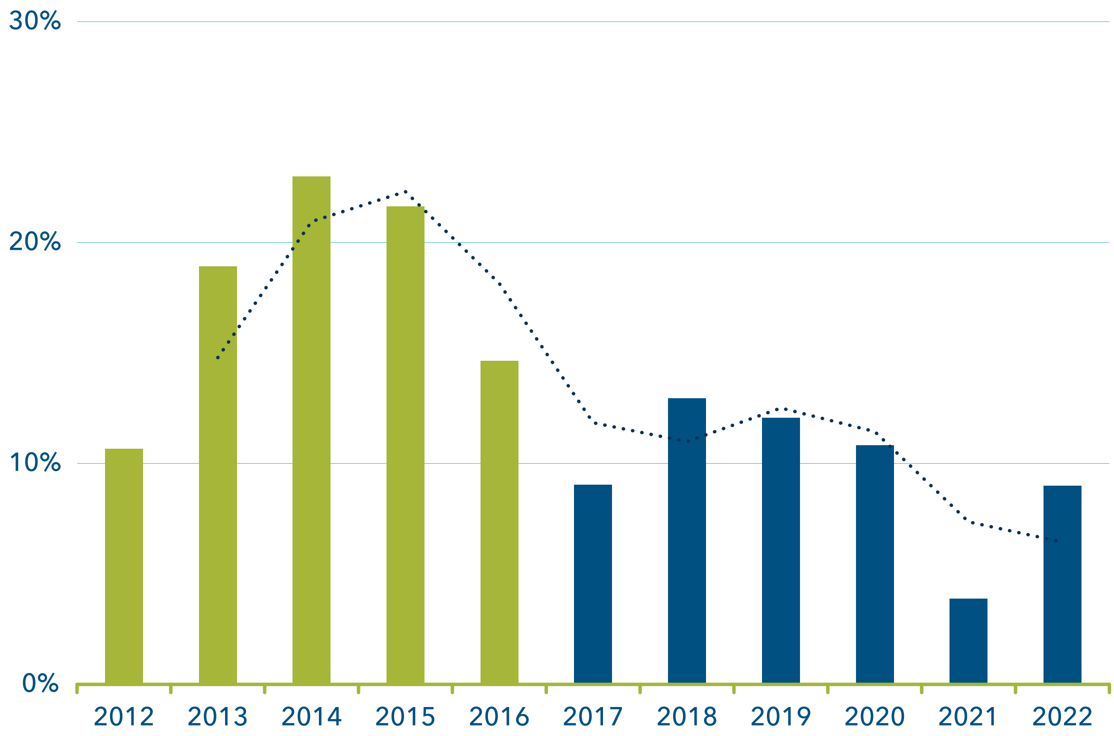


Figure 4: Percentage of vegetation related interruptions.

Since 2016 we have taken a proactive approach to vegetation management to help reduce unplanned outages by employing an inhouse vegetation coordinator and increasing our vegetation OPEX budget. The success of this approach is evident in Figure 4. We will continue this approach across this AMP period.

We have identified some high-level objectives for our vegetation management portfolio to guide our strategy and activities during the planning period.

Asset management objective	Portfolio objective
Safety & environment	Reduce the potential risk of incidents affecting tree owners undertaking trimming work to improve public safety. Have a risk-based approach by prioritising higher-risk trees.
Service levels	Ensure vegetation maintenance is undertaken by competent and network-approved contractors and meets all Health and Safety requirements.
Cost	Remain within budget and ensure a decline in operating costs by ensuring the appropriate parties take financial responsibility for any vegetation maintenance undertaken.
Community	Align vegetation maintenance schedules with other network maintenance to minimise disruption to customer supply. Have a proactive approach by providing advice, consultation and solutions for tree owners that aim to achieve the needs of all related parties.
Asset management capability	Better cataloguing of information using our asset management system and GIS and using the systems to map and forecast tree growth rate.

Table 3: Vegetation management portfolio objectives.

To achieve the above objectives, we strive to adhere to the following operational guidelines:

- **Cyclical schedules**: implementing routine vegetation maintenance schedules across our network to improve reliability and resilience
- **Risk-based proactive approach:** routine surveying and scoping of our network for encroachment and high-risk tree hazards providing solutions and advice to all tree owners and contractors
- **Contractor engagement:** actively engaging with all our network-approved contractors to ensure Health and Safety and industry regulation compliance, such as the various codes of practice and the Safety Manual - Electricity Industry
- **Public awareness**: improving education to the public by supplying information regarding the risks of vegetation near power lines, unauthorised trimming/cutting of trees, planting advice and the responsibilities of tree owners
- **Record enhancements**: developing robust record-keeping of vegetation data to help identify problematic areas, assist in planning maintenance schedules, and improve our resilience

Future opportunities

The use of technology and the collection of information will be important as we strive to maximise the value of our vegetation OPEX.

In-field surveying software: Improve our software and mapping systems and apply growth rates to assist proactive planning and identify potential encroachment issues

LiDAR: We will start to use Light Detection and Ranging (LiDAR) technology to support our inspections of power lines, poles, and other infrastructure. LiDAR will assist in checking line heights, identifying vegetation encroachment, and recording asset size and configuration information

Record management: We will integrate our vegetation records within our asset management system and utilise the capabilities within the system for robust record-keeping and data administration

Engagement: We will continue to improve our engagement with tree owners to ensure that the relevant parties meet their financial responsibilities

Vegetation management OPEX forecast

Our vegetation management expenditure forecast for the planning period is shown in Figure 5.

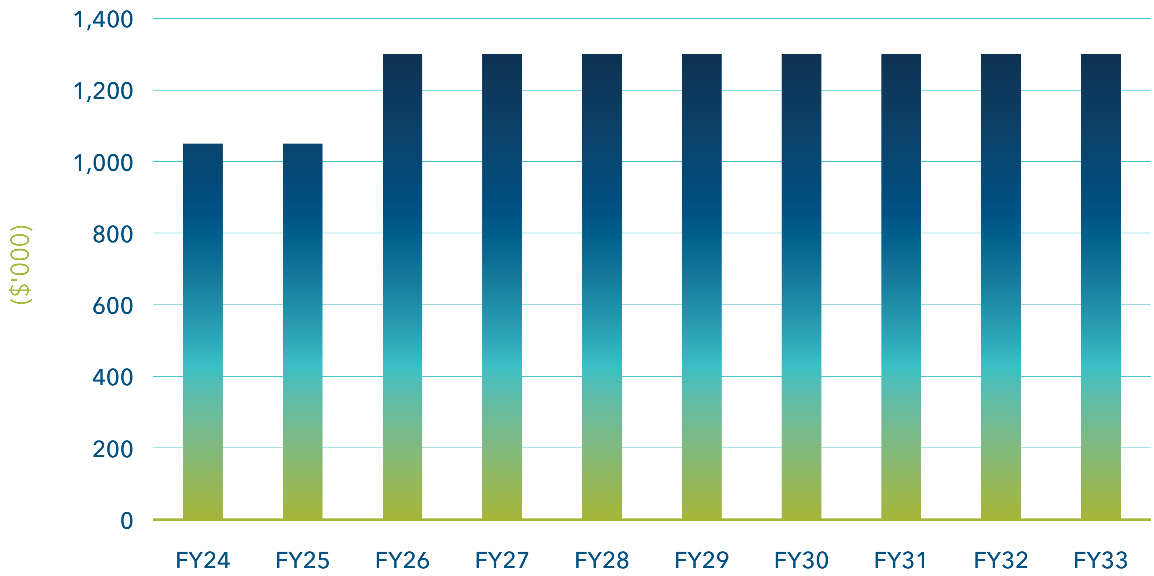


Figure 5: Vegetation management OPEX.

We have increased our vegetation management OPEX this year in response to cost increases and to support our reliability targets. Over the past year, the contracting rate for an arborist has increased by 15%, necessitating a corresponding increase in our vegetation budget. We are also planning to boost the frequency of vegetation inspections along our 33kV lines from annually to bi-annually.

The Electricity Hazards from Trees Regulations were amended 2021, providing greater clarity on the processes for notifying and assigning works to landowners. This has resulted in increased engagement with landowners regarding vegetation maintenance, and a corresponding increase in work requests. We have noted a rise in the number of landowners opting for tree removal rather than trimming in the past year.

Asset health indices

Asset health reflects the expected remaining life of an asset and acts as a proxy for the likelihood of failure. We have used asset health to inform our asset management approach for several of our asset fleets. Using Asset Health Indices (AHI), we can estimate the required future volume of asset renewals and forecast the health outcomes of our investment scenarios. In all cases, except for wooden poles, we employ AHI by following the EEA's Asset Health Indicator Guide.

The AHI categories are defined as detailed in the table below.

AH	Category description	Replacement period
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between 1 & 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 & 10 years
H4	Normal deterioration, regular monitoring	Between 10 & 20 years
H5	As new condition, insignificant failure risk	Over 20 years

A typical AHI graph for an asset type will be as depicted in Figure 6. Detailed AHI data for most asset types is given in this section. Where appropriate, the actual condition of an asset fleet is discussed rather than the age-based result.

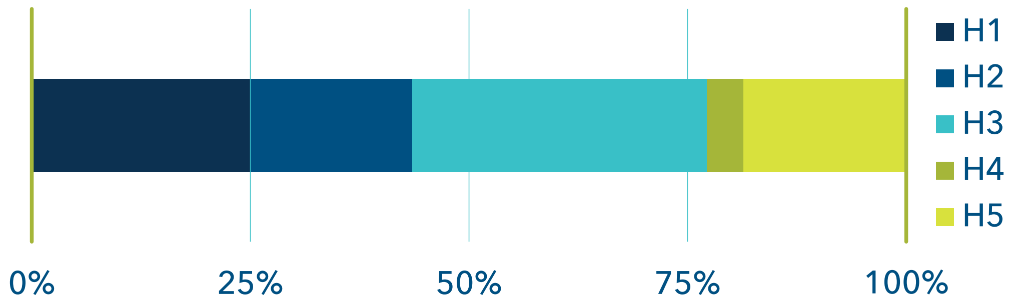


Figure 6: Example of asset health profile.

Developing CAPEX projections

Our approach to developing CAPEX projections involves several key steps. First, we inspect the condition of our assets and identify any that need to be renewed or replaced. This inspection process allows us to prioritise our assets based on their current condition and the potential risks they pose.

Once we have identified the assets that need to be renewed or replaced, we place them on our works programme. This step is important as it allows us to organise our work and ensure we address the most pressing needs first.

Finally, we either include the work in our annual budget or on our roadmap forecast. This step allows us to plan for the necessary CAPEX and ensure that we have the necessary funding in place to complete the work. This approach ensures that our assets are in good condition, minimising potential risks, and planning for the necessary CAPEX in a timely manner.

Our approach to developing CAPEX forecasts is also based on data and historical analysis of the assets. We use techniques such as Condition-based Asset Risk Management models (CBARM) and Failure Modes, Effects and Criticality Analysis (FMECA) to predict the optimal replacement or renewal time of the assets. These models consider the current condition of the assets, historical data, and expected usage to predict when maintenance or replacement is required. Additionally, we consider economic factors and the impact of the work on the community before making the final decision.

Overall, our approach to developing CAPEX projections is designed to be efficient, data-driven, and cost-effective. It is based on a thorough inspection of our assets, careful planning, and budgeting to ensure that we make the best decisions for our network and customers.

Consideration of non-network solutions

In the future, we intend to add non-network solutions as part of our ongoing efforts to improve our Asset Management systems. We will concentrate on integrating DERs such as solar panels and energy storage devices, as well as implementing demand-side management (DSM) programmes. When possible, we aim to identify the most appropriate non-network solutions, make appropriate assumptions, and estimate the costs associated with implementing and operating these solutions. This includes equipment, installation, ongoing maintenance, and operation costs. We will also factor in any potential savings or revenue generated by these solutions, such as reduced demand for network upgrades or revenue from providing grid services.

We anticipate that integrating DERs into our grid will reduce the need for costly infrastructure upgrades, improve grid reliability and resilience, and reduce greenhouse gas emissions. Additionally, we will explore the use of demand-side management systems. These systems manage electricity demand by encouraging customers to shift their usage to periods when demand is lower. These initiatives will reduce the need for costly network upgrades and improve grid reliability by lowering peak demand.

Once we clearly understand the costs and benefits associated with non-network solutions, we use this information to inform our CAPEX and OPEX projections for Asset Lifecycle Management. This includes developing detailed budgets and forecasts for the necessary CAPEX and ensuring we have the funding required to complete the work.

We believe that by comparing non-network solutions to traditional network-based solutions, we will be able to choose the most cost-effective and long-term option for the benefit of our customers. This will allow us to manage growing electricity demand, reduce the environmental impacts and minimise the cost of future network requirements more effectively.

Overall, adding non-network solutions into our Asset Lifecycle Management approach is a key component of our future strategy. We are committed to exploring and implementing these solutions to improve the efficiency and sustainability of our electricity distribution business.

Overhead structures

This section describes our overhead structure portfolio and summarises the fleet management plans for these assets. An overview of the asset fleets is presented, including population, age, and condition. Forecast expenditure for replacements and renewal for the planning period is also detailed. The portfolio includes the following asset fleets:

- Hardwood poles
- Softwood poles
- Mass-reinforced concrete poles
- Pre-stressed concrete poles

"Over the planning period, investment in overhead structures and conductors is forecast at $64M. This portfolio accounts for 48% of the renewal expenditure over the planning period."

In January 2014, a review of softwood poles sourced from fast-growing immature forests concluded that they would no longer be used on the network. Following the review, the estimated lifespan of existing softwood poles has been reduced from 40 - 50 years to 25 - 50 years. Any adjustment of estimated life will be based on condition assessment. A small percentage of earlier generation softwood poles, installed between 1985 and 1986, have performed much better as they were sourced from mature forests with more dense timber.

A review of our mass-reinforced concrete pole-making factory in 2013 determined that it was no longer sustainable. The factory was subsequently closed, and all new concrete poles are pre-stressed and purchased from industry-compliant suppliers. The remaining fleet of mass-reinforced poles will be managed until the end of their safe and useful life.

All new pre-stressed poles have a superior pole top strength compared to the mass-reinforced poles. These have performed well to date. A small percentage of other brands of pre-stressed poles are included in the fleet and have also given good service.

We have a large percentage of naturally durable and treated hardwood poles, which have performed well over the last 70 years. The introduction of steel poles is being considered initially for larger double-circuit structures and as a cost-effective alternative to hardwood in snow areas. Currently, steel poles would only be used for special projects with unique strength-to-weight requirements.

Portfolio objectives

The high level objectives for our overhead structures portfolio are shown below.

Asset management objective	Portfolio objective
Safety & environment	Safety in Design is considered for all structures. Replace structures using condition information before failure. Responsible disposal of obsolete poles and components. Ensure hardwood cross-arms are sourced from sustainable forests.
Service levels	Continual refinement of condition-based renewal techniques to improve feeder reliability (SAIDI and SAIFI), resilience and end of life predictions.
Cost	Provide cost-effective designs, construction, operational and disposal techniques for all structures and lines.
Community	Minimise planned outages to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Asset management capability	Provide adequate and appropriate resources to effectively design, build, operate, maintain, and support a safe and reliable overhead network.

Population and age statistics

The number and type of poles are summarised in the table below. Most of the 33kV sub-transmission network was installed in the 1960s and 1980s to meet the growing demand from the rural network. The growth spike of 1996 was due to the construction of the 30MVA dairy factory at Clandeboye.

Type	Number	% of total	Estimated life (Years)	Average age
Hardwood	13,792	31%	40-60	38
Softwood	5,601	13%	25-50	34
Concrete mass reinforced	22,447	50%	60-100	43
Concrete pre-stressed	2,745	6%	60-100	7
TOTAL	**44,585**	**100%**		

The majority of the 11kV and 22kV distribution network was built in the 1950s and 1970s. There was little development during the 1980s and early 1990s, with load growth accommodated within existing network capacity. Our wood pole age profile is shown in Figure 8.

Most concrete poles are more than 35 years old, with an average life of 41 years.

All new LV reticulation in urban areas must be underground in accordance with district plans. Rural LV overhead lines are maintained in conjunction with the 11kV systems.

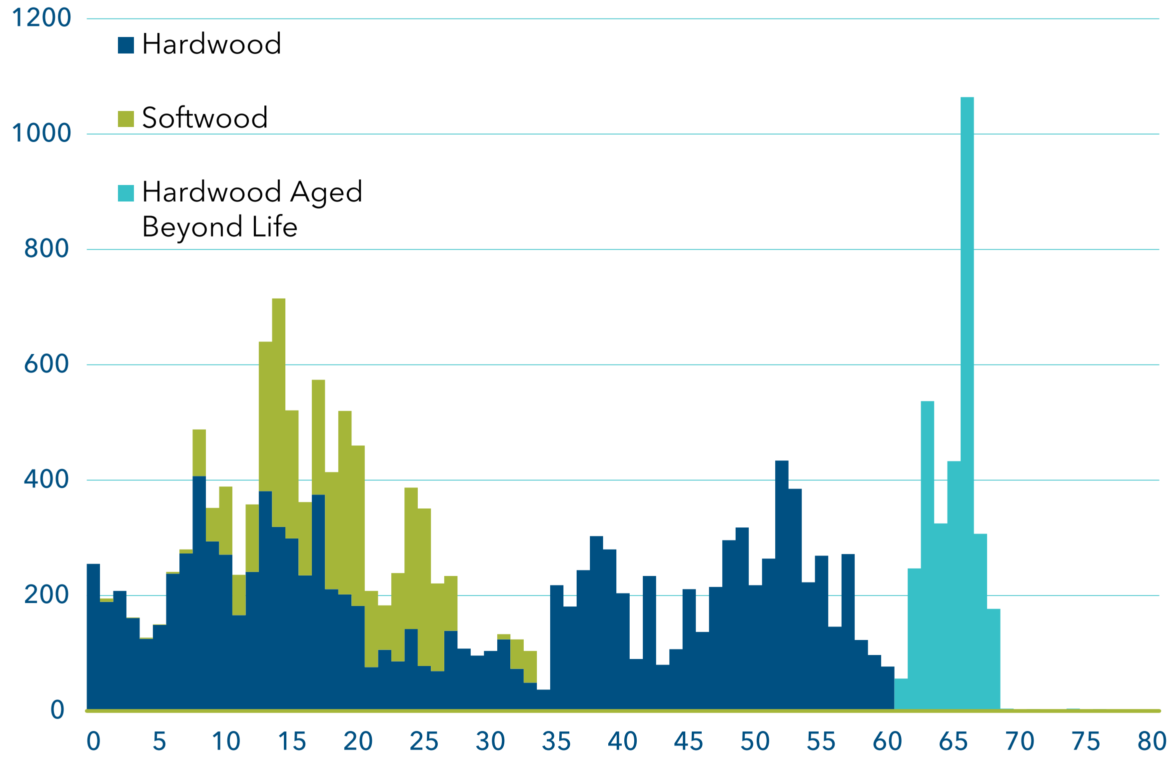


Figure 8: Wood pole age profile in years.

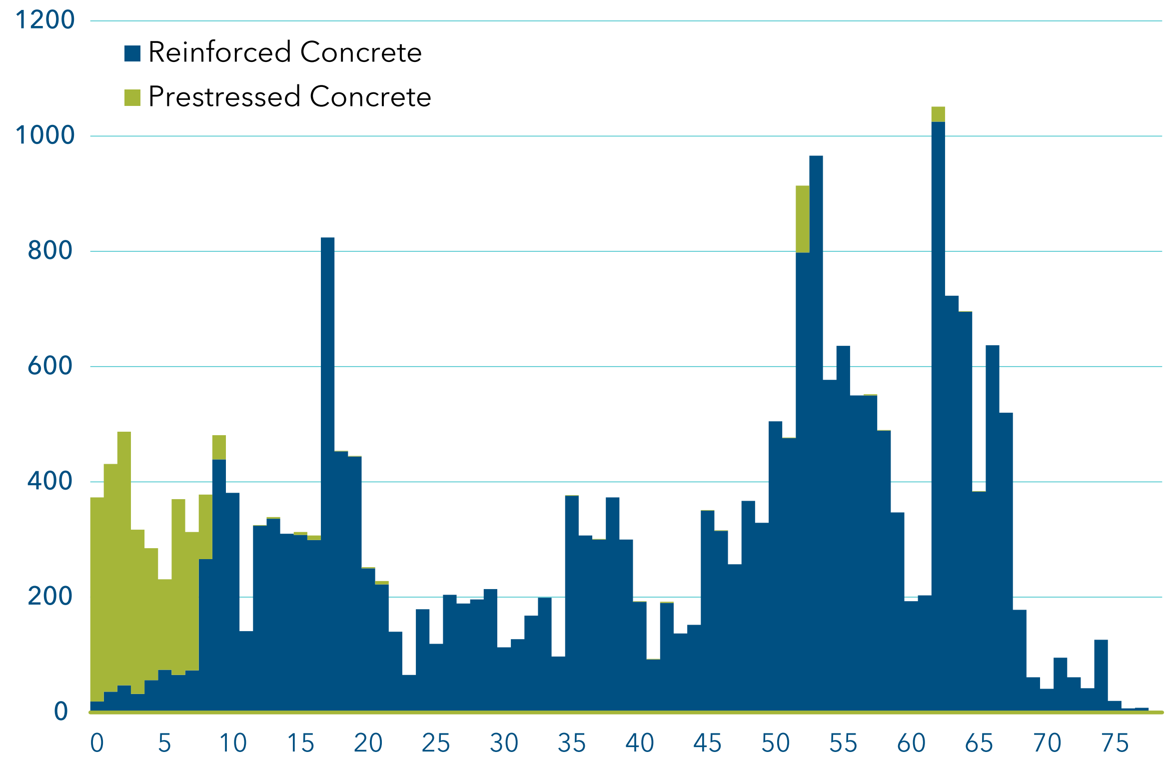


Figure 9: Concrete pole age profile in years.

Condition, performance, and risks

We have developed AHI for wooden poles that reflect the probability of failure for these poles. H5 (as new), H4 (normal deterioration) and H3 (increasing failure risk). AHIs are calculated using the age of the pole in the manner that the EEA's Asset Health Indicator Guide, propose. The past year's inspection records for wooden poles were then used to calculate the H2 (material failure risk) and H1 (end-of-life) AHI statistics.

The proportion of blue-tagged poles identified during the past year was used to calculate the H2 AHI indicator; and the proportion of red-tagged poles was used to calculate the H1 AHI indicator. The actual asset condition and historical data available were used to adjust the EEA Asset Health Indicator Guide numbers. The asset health profile for our pole fleet is shown in Figure 10.

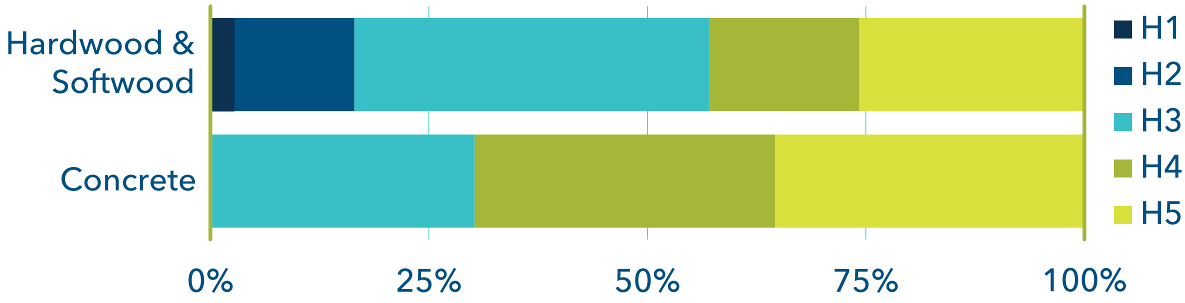


Figure 10: Pole structure asset health as of 2022/23.

The challenges relating to the condition and performance of poles include:

- Risk of premature softwood pole failure due to brown rot or structural degradation. We inspect poles prior to their 25th year in service and more frequently towards end-of-life. We liaise with other networks that have experienced similar issues to discuss appropriate strategies. We no longer use softwood poles, and a replacement programme is in place. Replacing these poles improves our resilience significantly.
- Mass-reinforced concrete poles have generally performed well. There are few signs of premature condition deterioration, and failures are primarily due to vehicles, imbalanced snow loads, or third-party influences such as trees. A very small percentage have failed due to chloride or carbonation penetration. These penetration failures could be attributed to poor quality concrete and/or workmanship on any given day of manufacture.
- The pre-stressed concrete pole fleet is relatively young. To date, they have performed well. They are lighter, offer superior strength and have a longer life expectancy. However, some of the longer-length poles are susceptible to damage during fitting and erecting due to deflection from their own mass.
- Naturally durable and treated hardwood poles have performed well but require routine inspection below ground after their 25th year in service. This inspection identifies 99% of threatening defects. However, we have had the odd failure below the 500 mm deep inspection zone.
- Hardwood cross-arms have a life of 30 to 40 years and are therefore generally replaced before the pole's end of life. Cross-arms are replaced when condition assessment determines that they can no longer support serviceability loads.

Design and construct

Our legacy network was designed using the first principles of engineering practice, which continues today through a combination of inhouse design spreadsheets, standards, and the proprietary software CATAN. The software we use and our standards comply with the requirements of AS/NZS 7000:2016 Overhead Line Design and its related standards. The principles of safety in design were introduced in 2016.

Existing overhead infrastructure will only be undergrounded for the following reasons:

- Supported by health and safety reasons
- Justified by engineering investigation
- Required by a District Plan

Existing overhead lines will be maintained with like-for-like overhead components.

Most of all overhead line design is done inhouse, while a small portion has been contracted to consultants familiar with our standards. We have design standards and construction methods which are managed through our drawings management system, Adept. Version control and transmittal of drawings, standards, and specifications are two of the main strengths of the system.

Most of our large overhead line projects are tendered in the market. Smaller projects are issued to our subsidiary contractor on an industry-aligned rate card system.

33kV sub-transmission lines are a high priority due to their potential impact on network reliability. Sub-transmission lines are designed and built to the highest standards and, in the case of Clandeboye and Pareora, have duplicate circuits to provide SoS. The remaining lines are single 33kV circuits.

The 11kV distribution lines and cables are typically open-ringed in the Timaru CBD and industrial areas and in the denser-loaded suburban and rural areas. LV lines and cables also have interconnection in densely populated urban areas but are typically short spur lines in other areas.

The open ring system is used for underground cable systems where fault repair time is much longer than for an overhead system. The probability and extent of an underground system fault is much lower than for an overhead system, as overhead lines are exposed to risk from severe weather, bird and vegetation interference, and vehicle damage. The risks to underground cables include accidental damage from contractor excavations and climate change related events, such as flooding, subsidence, silt, and erosion, and earthquakes.

Historically, in dry-land farming and cropping days, lightly loaded rural areas were arranged as a single spur overhead line. However, with load density growth in the past 20 years due to land use change to dairy farming, rural lines have been built or upgraded to be open-ringed, providing alternative supply routes where possible, to support dairy and irrigation load.

Operate and maintain

Our condition assessment programme is designed to identify and replace defect poles before failure, and we aim to carry out:

- A detailed inspection of every pole on a rolling 10-year basis, starting on its 25th anniversary. This means we inspect 10% of our total overhead line infrastructure that are 25 years or older.
- The condition assessment data is reviewed, analysed and a replacement programme implemented. Using historical climate data, we will evaluate our susceptibility to weather-related incidents such as high winds, flooding, snow, subsidence, and slipping. This will help us gain a better understanding of these risks and prepare for potential weather events.
- Cross-arm, insulator and other pole-top equipment condition-based renewals are carried out during pole replacement.

Our condition assessment programme was introduced in 1985 and initially focused on areas predominantly reticulated with hardwood poles installed between 1955 and 1961 with approximately 10% to 20% of poles being replaced after each inspection. Initial inspections of urban areas also focused on wood poles; however, a full condition assessment programme for urban reticulation, including all small townships, has been introduced.

The EEA Timber Pole Condition Assessment Guide is used as the basis of our overhead asset inspection specification. This guide has the potential to provide commercial, compliance and intangible benefits to organisations and provide safety assurance benefits to the wider public. It will also aid in:

- Consistent benchmarking of asset health assessment information and ratings across all different pole asset owners
- Support improvements in asset management and commercial analysis of investment in pole assets
- A consistent industry approach to pole assessment that supports regulatory disclosure and funding models (for example, to the Commerce Commission)

Each timber pole is visually inspected over its length above ground and below ground to a depth of 400 mm via excavation. The excavation inspects the integrity of the timber in the zone of soil bacteria activity and involves the removal of sapwood to measure the remaining healthy timber. The diameter of the healthy hardwood is used to determine the remaining serviceability life of the pole, based on the ultimate design load being met for a further 10 years. A GoPro camera fixed on top of a hot stick, or a drone, are used to scrutinise pole top component condition. We also use drones to conduct pole-top inspections.

Our cyclic 10-year condition-based renewal process ensures confidence in the condition of the oldest remaining poles. It effectively staggers the capital required for end-of-life replacement. The inspection aims to identify and document all components that may not be able to support serviceability and ultimate design loads, and to comply with clearances specified in the Code.

A two-coloured tag system is used to identify suspect poles. A standard red tag identifies poles at risk of failure under serviceability loads, requiring replacement within three months of inspection. A standard blue tag indicates that a pole may not be capable of supporting ultimate design loads beyond the next 10 years. Applying a safety factor of two, the blue tagged poles are replaced within five years of inspection. Poles found to be incapable of supporting ultimate design loads are replaced in conjunction with red tag poles.

To remove human subjectivity, new technology for wood pole assessment has been trialled to establish the best combination of available tools. None of the technological solutions evaluated today has instilled confidence in the ability to assess pole conditions accurately.

Our Defects System data is received from the field and/or public and corrective maintenance, or asset replacement, is scheduled based on the severity of the defect priority. Our five defect priorities codes range from urgent (correction within 48 hours) to trivial (Routine maintenance cycle).

The sub-transmission lines built in recent years are due for inspection and maintenance in the 25th year of service unless the line condition suggests otherwise. Our sub-transmission line inspections are prioritised based on age and recent performance.

Renew or dispose

Concrete poles have an estimated life of 60 to 100 years, softwood poles 25 to 50 years, and hardwood poles 40 to 60 years. New softwood poles and reusing softwood poles are banned on the network.

A programme to replace the existing fleet of softwood poles over several years has been prioritised in the following order:

- Conjoint 33kV and 11kV lines
- 33kV lines
- 11kV lines with heavy conductor
- All others during refurbishment, unless required earlier

Very few concrete pole replacements are expected due to age in the next 30 years. Hardwood poles are replaced at end-of-life. However, in some cases where a pole with extensive equipment has failed at ground level but still in good condition above ground, it is reinforced with a galvanised steel splint to extend its useful life.

An age-based replacement estimate would indicate that, on average, around 750 poles would need replacing each year. However, adequate maintenance of lines renders the age-based replacement philosophy unrealistic. We use actual condition to inform the replacement of wooden poles. As such, we are currently replacing around 400 poles per annum and aim to replace 750 poles per annum.

We have approximately 10,000 wood poles and 17,000 concrete poles over 25 years old, so assessing these conditions over 10 years requires 3,000 to be assessed annually. Our assessment target has increased to 5,000 poles per annum so that we can identify more poles to replace. More condition-based assessments will help us confirm that aged poles remain fit for purpose, even when it ages past its estimated life expectancy. Consequently, we foresee that our pole replacement costs would double within the next three years.

Disposal of treated wood poles is expected to pose an issue until an environmentally friendly method can be found. Present disposal consists of them being sold to the public to recycle or given to non-profit organisations for community projects. Damaged concrete poles are either gifted to landowners or crushed and recycled by local contractors. Untreated hardwood is sold for firewood or recycling.

Our replacement and renewal programme is incorporated with the conductor replacements and renewals as detailed in the next section.

Overhead conductors

Our overhead conductor fleet consists of copper (Cu), galvanised steel (Fe), steel-reinforced aluminium (ACSR), all aluminium (AAC) and, more recently, all aluminium alloy (AAAC). In the 1950s some of the ACSR conductor was ungreased however we do not know the full extent or location of this conductor. Most areas of its use have been discovered over time and these are monitored closely for corrosion. Early identification is critical, and some non-greased conductors have been replaced already.

While copper conductor, in general, has given good service, the smaller copper conductor is inherently more susceptible to tensile failures than ACSR and have been stretched over repeated storm events. These have been identified and their replacement will be ongoing for the foreseeable future.

The circuit kilometres of all overhead network lines constructed, by voltage level, three-phase, single-phase, and single-wire earth return (SWER), are shown in Table 7.

Not all conductors perform uniformly, with some single strand (LV) and seven-strand copper and smaller smooth-bodied aluminium conductors, older than 50 years, exhibiting signs of reduced ultimate tensile strength. To date, the performance of the seven strand galvanised steel conductors in the Mackenzie area has been acceptable and the conductor is not considered at risk of failure.

Voltage	3-phase (km)	1-phase (km)
110kV	24	N/A
33kV	251	N/A
22kV	27	116
11kV	1,928	813
400 V	225	127
TOTAL	**2,455**	**1,056**

Table 7: Overhead circuit length in km.

Most reported conductor failures are due to joints failing through a mixture of poor design, incorrect application, and incorrect size.

Investment in overhead conductor for the planning period is rolled into the overhead structure budgets in Table 11. We are currently only replacing short sections of weaker conductor that have failed due to extreme weather events causing vegetation to be blown into the lines.

Portfolio objectives

Asset management objective	Portfolio objective
Safety & environment	No injuries to the public or contractors as a result from conductor failure. No property damage as a result from conductor failure.
Service levels	Reduced SAIDI and SAIFI by timely conditioned based renewals. Continual refinement of end-of-life predictions techniques.
Cost	Provide cost-effective designs, construction, operational and disposal techniques for all lines. Establish a balance between electrical conductivity and mechanical strength in conductor choice.
Community	Minimise planned outages to customers by coordinating replacement with other works. Minimise landowner disruption when undertaking renewal work.
Asset management capability	Provide adequate and appropriate resources to effectively design, build, operate, maintain, and support a safe, reliable overhead network.

Table 8: Overhead conductor portfolio objectives.

Population and age statistics

Figure 11 details the overhead conductor length at a sub-transmission level for the types of conductors that we use. All our AAAC conductor is 10 years old or younger with a minimal amount of copper still used at sub-transmission level.

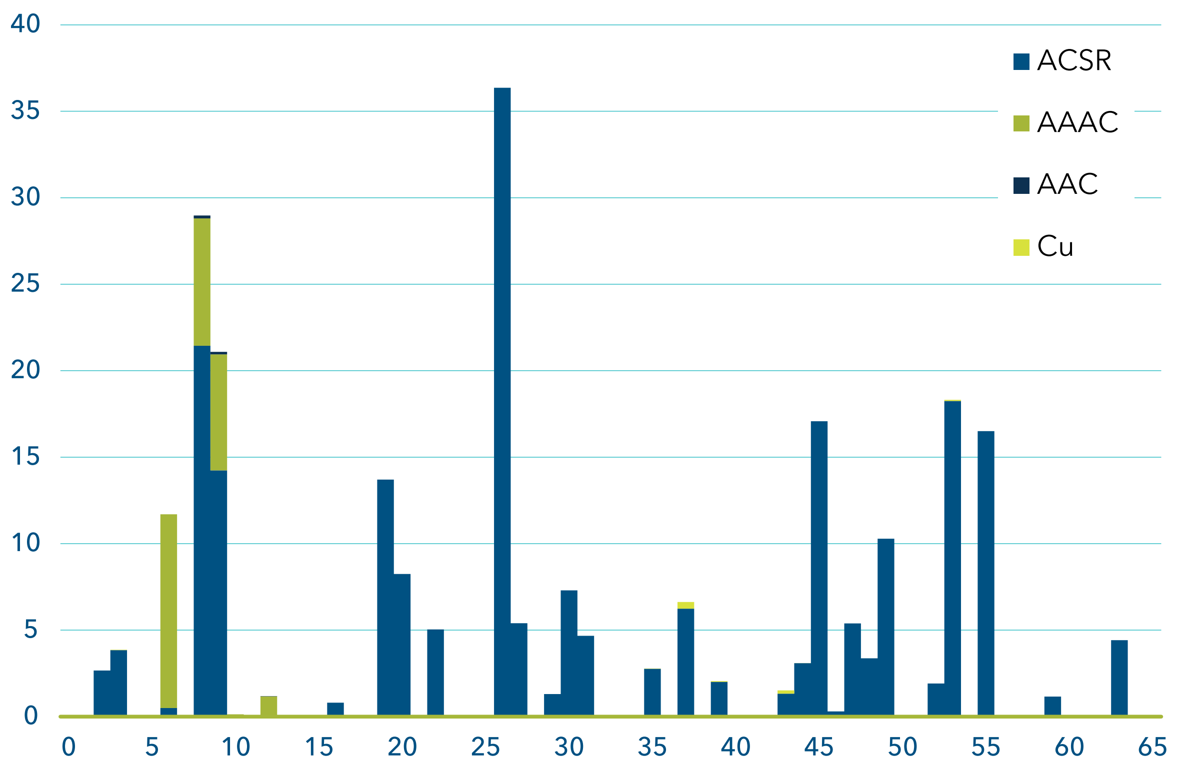


Figure 11: Sub-transmission conductor age profile in years.

The majority of copper conductor is 51 years old, and in short sections in some of our zone substations is part of the bus structures. Since these are not under significant tension, we do not regard them as at risk.

ACSR conductor makes up most of our overhead distribution lines and consists mainly of Herring, Gopher, Magpie and Mink types. Details on our ACSR age profile across all voltages are depicted in Figure 14. The majority (31%) of our ACSR conductor is of Herring type. Of this, 77% is 50 years or older. On average, we replace and renew our overhead line infrastructure at a rate of 5% per annum. Figure 12 depicts our distribution conductor by type, age, and quantity.

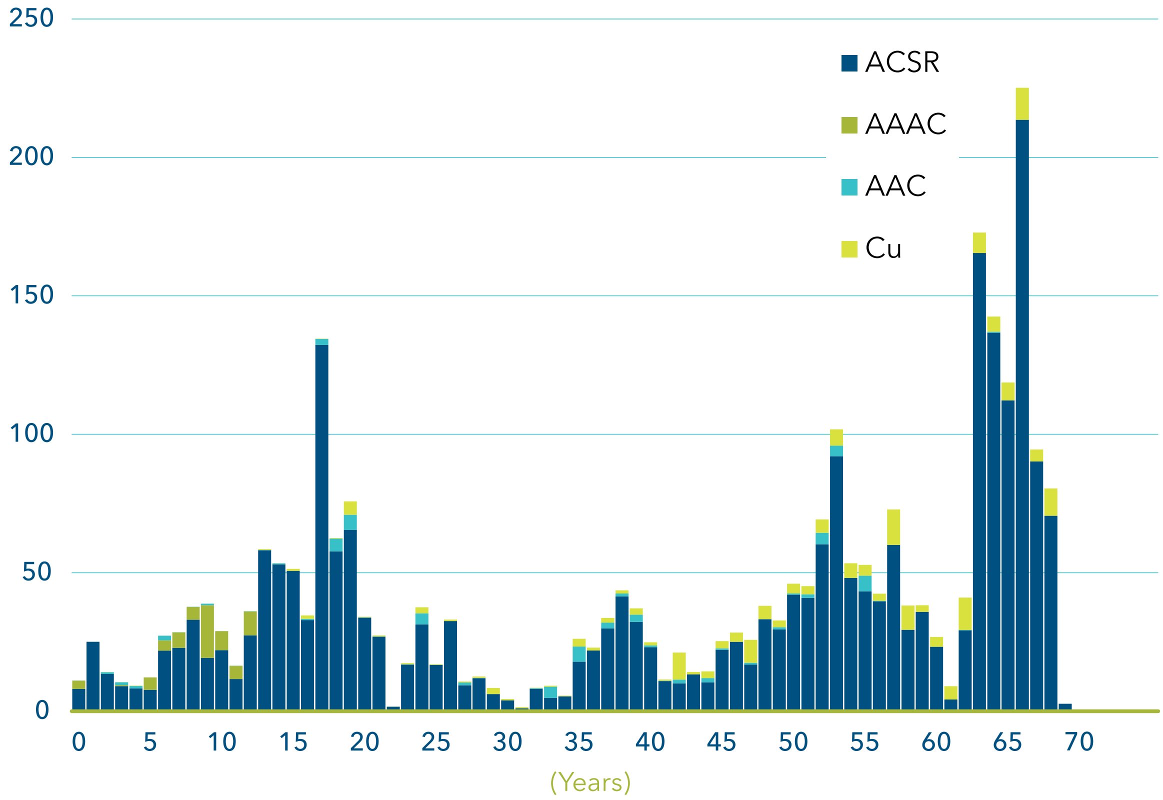


Figure 12: Distribution conductor age profile in years.

Type	Length (km)	% of total
AAAC	88	2.5%
AAC	99	2.8%
ACSR	2,804	80.2%
Cu	412	11.8%
Other[1]	92	2.6%
TOTAL	**3,495**	**100%**

Table 9: Overhead conductor type length and percentage of total.

Most of our LV overhead conductor networks are in urban areas and are constructed of copper.

[3] This conductor information exists on paper records only but will be loaded into our EAM as part of a planned asset audit project.

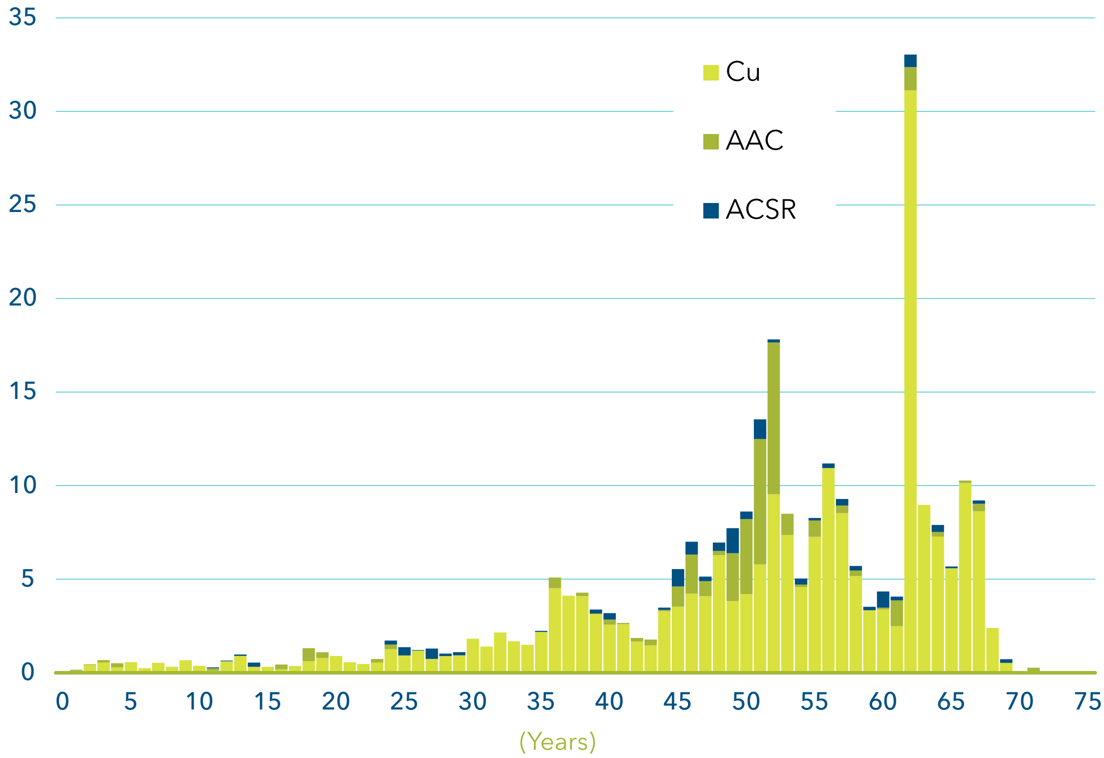


Figure 13: LV conductor age profile in years.

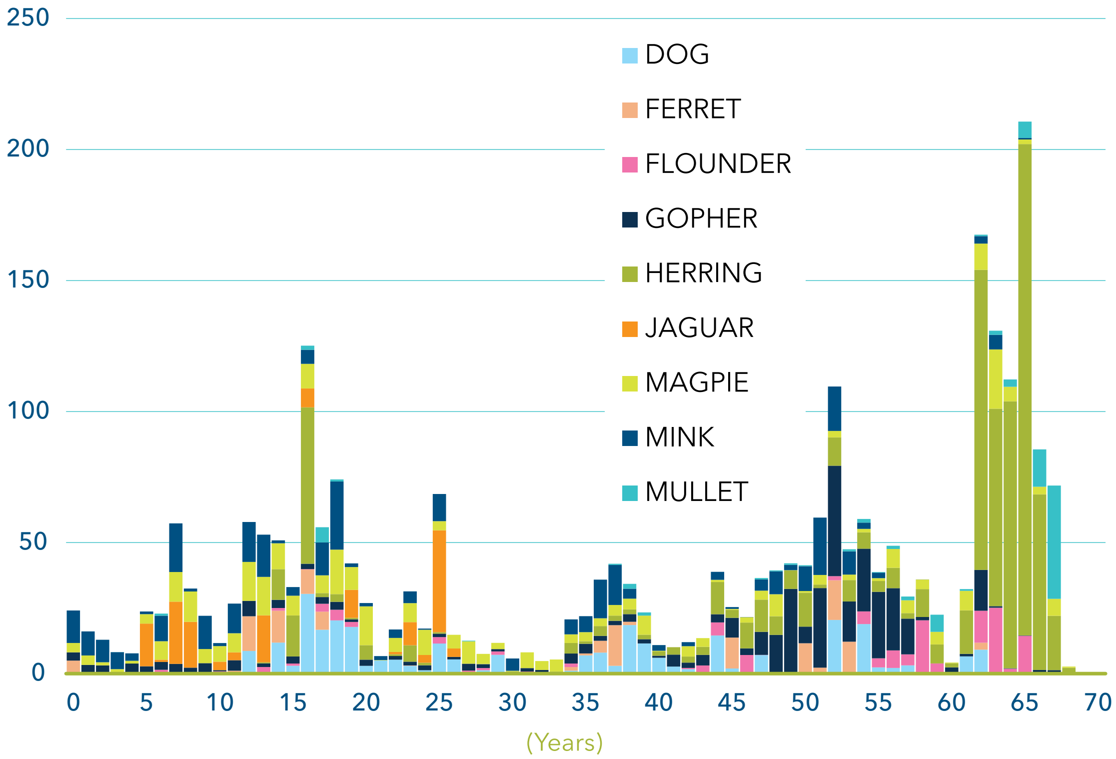


Figure 14: ACSR conductor age profile in years.

Condition, performance, and risks

Early ACSR conductors used an ungreased galvanised steel core and are susceptible to premature corrosion in the comparatively hostile coastal environment. The condition of this type of conductor is closely monitored, especially around joints and terminations.

Assessments will determine replacement priority for smaller inherently weak copper and ACSR conductors, and the older smooth body type conductors, that frequently suffer damage during weather events. Special focus is on areas where conductor failure would disrupt the largest number of customers and/or pose a threat to public safety.

Some areas of the network were reticulated using smooth body ACSR conductor strung at 40% of its ultimate tensile strength due to designs incorporating many large spans. Some of this conductor has been subject to Aeolian vibration over its lifetime however this has proven to not have been damaging. The age-based asset health profile for overhead conductors is shown in Figure 15.

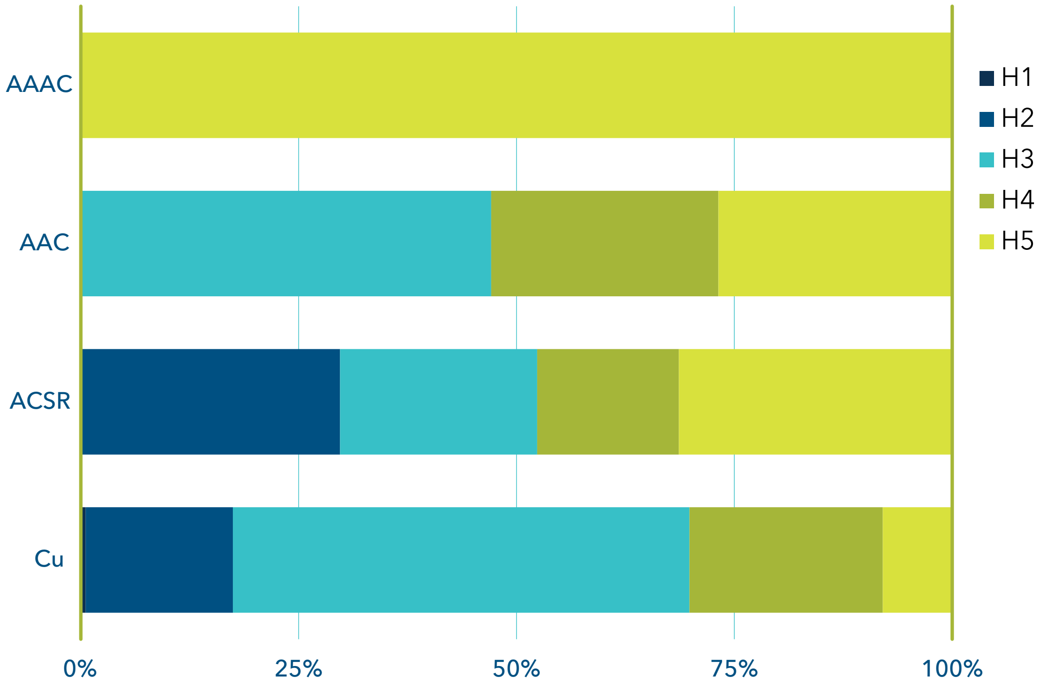


Figure 15: Overhead conductor asset health as of 2022/23.

Corrosion of ACSR conductors has also become prevalent under the older type parallel groove (PG) clamps, resulting in a small number of premature conductor failures under the clamp. PG clamps are now routinely replaced with modern equivalent connectors during maintenance.

Some ungreased conductors installed in coastal environments between Studholme and Glenavy are showing signs of corrosion. Due to capacity demands, a large amount of the rural overhead network has been rebuilt in recent years, resulting in the replacement of the older, inherently weak and corrosion susceptible conductors.

We embarked on a conductor testing regime in 2019 where we took samples of overhead line conductor and had them assessed to determine the remaining life. This regime is ongoing. Our network area is divided into four distinct areas to reflect distance from the ocean and elevation.

These areas are:

- Zone 1 - within 5km of the coast – sea spray
- Zone 2 – more than 5km from the coast and above 200m elevation
- Zone 3 – between 200m and 550m elevation
- Zone 4 – above 550m elevation

The zones are depicted in Figure 16. To date, we have tested conductor types in zones as detailed in Table 10. The assessment for remaining life is based on the following measures:

- Visual assessment of conductor deterioration
- Dimension checks
- Mechanical testing, tensile strength, breaking load, and wrap testing of individual wires (steel and aluminium) in accordance with relevant standards
- Metallographic assessment
- Alignment to British Standards BS 251 and Australian Standards AS 3607
- Alignment to Transpower standard TP.SS 02.17 - Transmission Line Condition Assessment

In our determination of remaining life for conductors, we have used the recommended criteria of either a 20% loss in ultimate tensile stress of the whole conductor, or a 15% reduction in cross-sectional area of the aluminium cores. This criterion varies between conductor types. We will review these criteria in consultation with experts as part of the reassessment program.

Conductor type	Zone	Sample age (Years)	Remaining life (Years)	Reassessment (Years)
Herring	2	57	24 to 31	12 to 15
Herring	4	60	24 to 31	12 to 15
Gopher	2	34	116	30 to 40
Gopher	3	63	147	30 to 40
Mullet	3	53	15 to 70	5 to 10
Mullet	3	53	15 to 70	5 to 10
Herring	1	50	17 to 28	7 to 10
Mullet	1	66	23 to 32	10 to 15
Herring	2	57	20 to 40	12 to 15
Quail	1	57	18 to 22	7 to 15

Table 10: ACSR cable type test results.

Our all-aluminium conductors (AAC) and all-aluminium alloy (AAAC) conductors are in good condition.

We are participating in a new industry-wide initiative looking to provide a more informative method of identification for predicting the remaining life of conductors.

Design and construct

Our overhead lines are designed to the AS/NZS 7000:2016 Overhead Line Design standard.

Choosing a conductor wire size and material involves considering electrical, mechanical, environmental, and economic factors. Our new lines are constructed with modern ACSR and AAAC conductors with superior strength. The modern design has greatly reduced the structure and pole damage associated with the tensile failures of older inherently weak conductors.

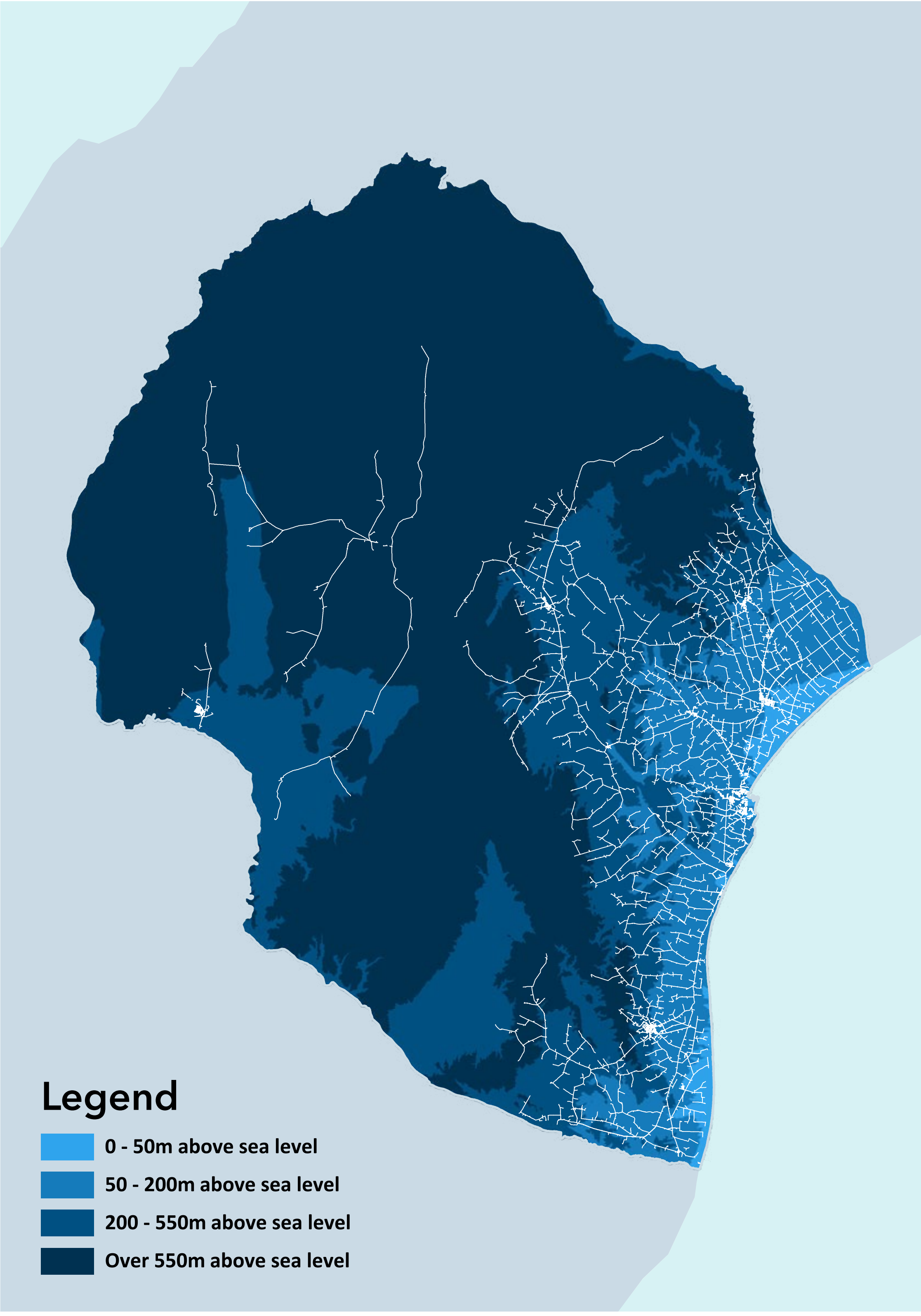


Figure 16: Network zones.

Operate and maintain

Condition assessment of conductors is non-intrusive and is carried out in conjunction with structure inspections on a 10-year cyclic programme. Intrusive inspections are performed, through the conductor sampling programme to support renewal decisions.

Old parallel grove clamp connectors promote corrosion between the conductor and clamp. These are routinely replaced, as mentioned earlier.

Conductors with broken strands are repaired with wrap on sleeves or armour rods to prevent further damage.

Out of sag spans are routinely re-pulled to prevent conductor clash.

Renew or dispose

The dairy and irrigation industry has driven the renewal of many old and less resilient conductors, especially at network extremities.

By overlaying storm damage data maps, we have been able to identify areas of repeat conductor damage. This evidence allows us to prioritise conductor renewals based on an assessment of risk, SoS, economic impact, and safety.

Although we anticipate that climate change may exacerbate storm-related damage to our network, particularly in areas prone to flooding, high winds, and snow, we currently expect the frequency of overhead conductor replacements to remain constant over the next 10 years and then gradually increase beyond the current planning period.

Old conductor is generally sold for scrap with a selection of older types, in good condition, retained for emergency repairs.

Our overhead line replacement and renewals for the 2024 period are detailed in Table 11.

Location	Timing (FY)	Estimate ($'000)
Colliers Road – incl. L132 - 20.5km	2024	421
Crowes Road, Mink to Jag W190 to A1212 - 1.5km	2024	162
Maungati - Craigmore Valley Rd - 41.5km	2024	550
Pleasant Pt township - 309 Poles	2024	200
Simons Pass Stage 2	2024	821
Timaru City Stage 3 - 704 poles	2024	1227
Timaru City Stage 4 - 632 poles	2024	1335
Temuka - Geraldine 33kV - 17.5km	2024	701
Twizel Township overhead line Stage 3 - 270 poles	2024	550
Waitohi Temuka	2024	359
Wilson Street Maintenance	2024	50
Softwood Pole Replacement	Annually	200 per annum.
TOTAL		**6,880**

Table 11: Overhead line replacement/renewal program.

Underground cables

This section describes our underground cables portfolio and summarises our associated fleet management plan. The portfolio includes three fleets:

- Sub-transmission cables
- Distribution cables
- LV cables

This section provides an overview of these assets, including their population, age, and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

Sub-transmission cables:

The sub-transmission cable fleet predominantly operates at 33kV, though we also classify our 11kV Timaru supply cables to the CBD as sub-transmission cables because of their relative importance and mesh configuration compared with the open ring main 11kV feeder cables. The assets include cables, joints, and pole terminations. The two types of cable used are cross-linked polyethylene cable (XLPE) and paper insulated lead cable (PILC).

Distribution cables:

The distribution fleet operates at 11kV. The main assets within the fleet are cables, joints, and pole terminations. We have two main types of cable insulation in the network at the distribution level, namely XLPE and PILC.

PILC has been used internationally for over 100 years and manufactured in New Zealand since the early 1950s. PILC uses paper insulating layers permeated with non-draining insulating oil. The cable is generally encased by an extruded waterproof lead sheath covered and wrapped in tar permeated fibre material, PVC, or polyethylene. PILC cables have a good performance record in the industry.

The first XLPE cables were installed in our area after the mid-1970s. Consequently, our XLPE cables are of the more recent technology and their construction, operational integrity and safety features are improved over the earlier generation of XLPE cables. All cables installed on our network today, including repairs to existing PILC cables, are XLPE.

LV cables:

The LV cable fleet operates at below 1kV (230/400 V). The main assets within the LV fleet are cables, link boxes, LV cabinets, in-ground boxes, and pillar boxes.

The number of customers on a particular LV network section depends on the load density. The distance from the distribution transformer to the last customer is usually limited to around 400 metres.

Customer service lines connect to our LV cable network by a cable from a pillar box usually located on the property boundary. The integrity of pillar boxes is a key public safety concern. We have a variety of different styles and materials installed on our network.

> Investment in underground cables for the planning period is forecast at $17M over the planning period. This includes asset relocations (i.e., overhead to underground conversions), replacement and renewals, and growth projects. This portfolio accounts for 13% of the total expenditure over the planning period.

Underground cable portfolio objectives

Table 12 summarises our underground cable portfolio objectives.

Asset management objective	Portfolio objective
Safety & environment	No public safety incidents by coming into contact with our cable network. Manage all excavating on our network via BeforeUDig process.
Customer service levels	Minimise interruptions to customers when performing asset management activities on our cable network. Keep customers informed of planned outages. Continue programme to construct mobile generation connection points across our cable network.
Cost	Ensure investment is appropriate through a risk assessment and risk reduction review. Plan and resource maintenance activities to minimise plant outages.
Community	Appropriate traffic management to minimise disruption in the event of cable repair in roadways. Ensure access to private properties when trenching in roadways.
Asset management capability	Load and populate asset data on our Enterprise Asset Management (EAM) module. Develop fleet maintenance strategy and programme and implement in EAM. Continue staff training on various asset types through EEA.

Table 12: Underground cable portfolio objectives.

Population and age statistics

Our network contains over 815km of underground cabling of both XLPE and PILC varieties. The cables supply power at 230/400 V, 11kV and, to a lesser extent 33kV.

The quantity of cable for various voltage levels on our network is shown in Table 13.

Voltage	Length (km)	% of total
240 V	8	1%
400 V	361	42%
11kV	435	51%
22kV	11	2%
33kV	34	4%
TOTAL	**849**	**100%**

Table 13: Underground cable circuit lengths.

The Optimised Deprival Valuation (ODV) handbook gives us a lifespan of approximately 70 years for PILC cables. We assume a life of approximately 40 years for XLPE cables installed prior to 1986, and a life of 60 years for those installed afterwards. The difference is due to advances in XLPE materials and construction, made in 1986, that led to XLPE cables having a significantly longer service life. It should be noted that our lifespan assumptions are conservative as the areas in which the bulk of our cables are laid are considerably drier than those for which the ODV handbook figures were calculated.[4]

[4] For modern XLPE cables.

Almost all 33kV cables on our network are less than 40 years old and are all XLPE type. The age profile of our sub-transmission cables is shown in Figure 17.

Most of our sub-transmission cable that is 17 years old are the two cable circuits between the Temuka GXP and our Clandeboye substations supplying Fonterra. We have an additional 24km of 33kV cables that is currently operating at 11kV. This higher rated cable was installed to allow a future upgrade in operating voltage when the load requires.

The HV and LV distribution networks include distribution boxes, oil switches, and RMUs. Most of these assets have been installed in the last 20 to 40 years (with an estimated life of 60 to 80 years). 50% of the underground 11kV distribution network was installed in the last 25 years. The majority of the oldest cables are of PILC construction, which has a 70–100-year life.

The more recently installed cables (20-to-40-year age group) are of PVC sheathed, XLPE core insulation construction, and have an expected service life of 60 years.

Our LV cables are predominantly XLPE insulated, with a small quantity of older LV PILC cables. The unknown insulation type in Figure 19, which are less than 25 years old, we expect are mostly XLPE.

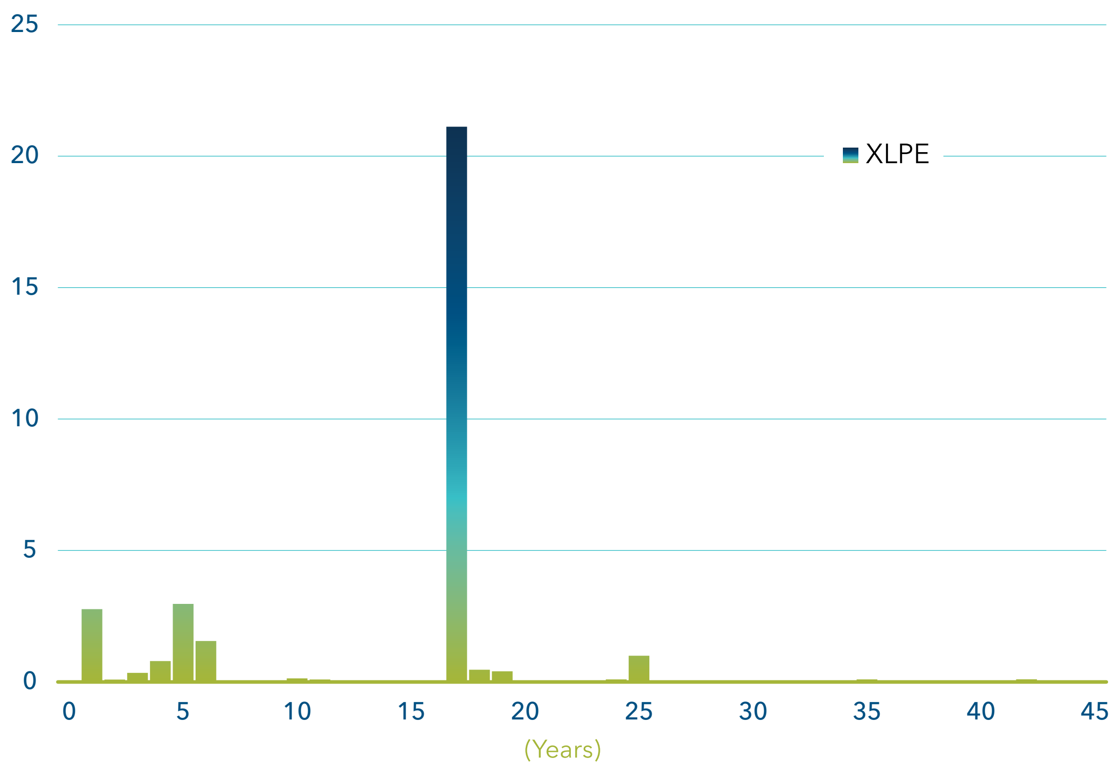


Figure 17: Sub-transmission cable age profile in years.

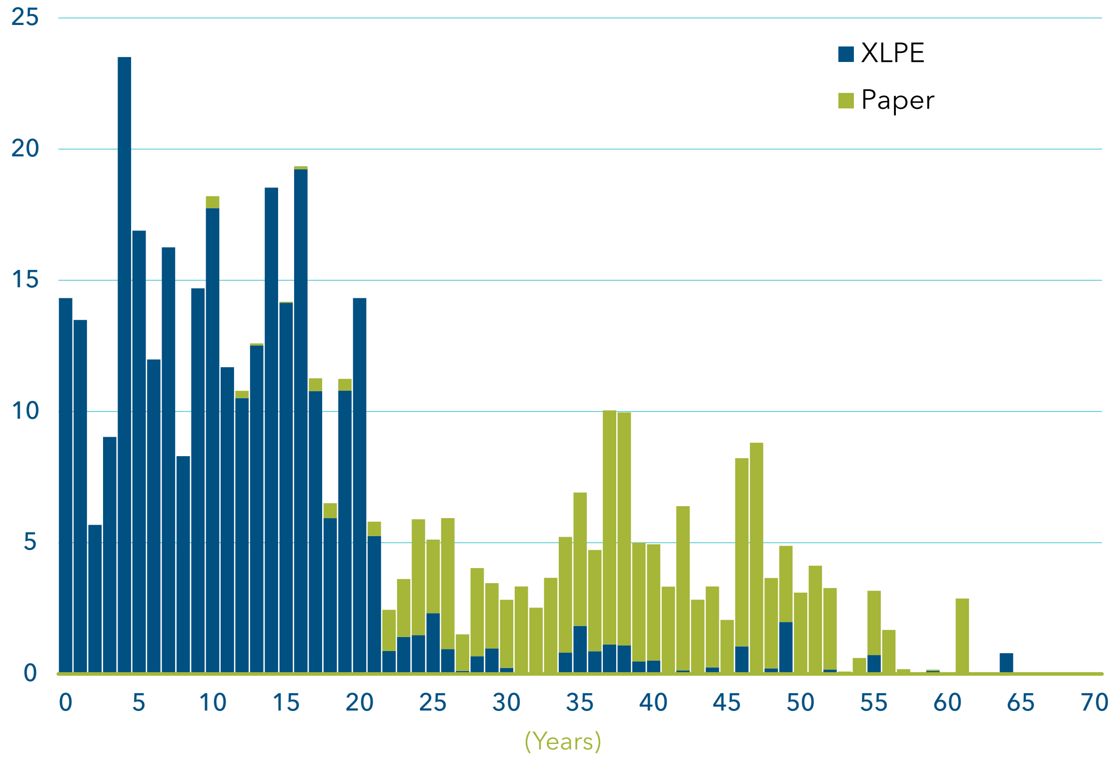


Figure 18: Distribution cable age profile in years.

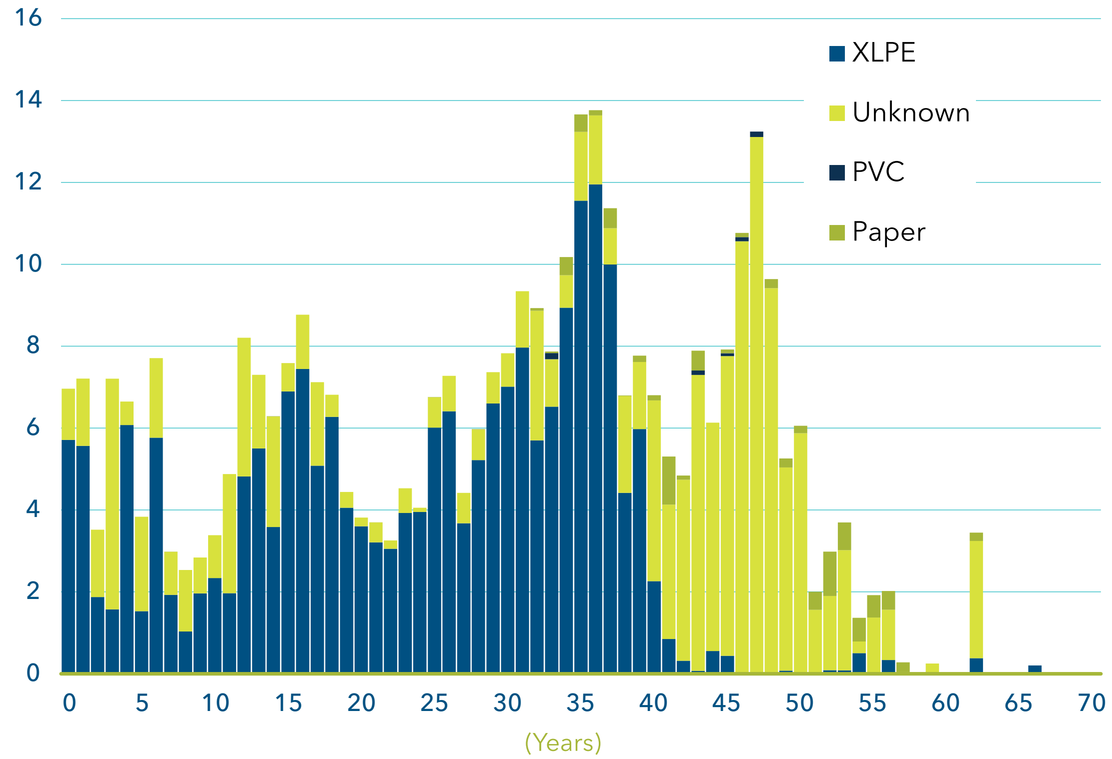


Figure 19: LV cable age profile.

In the absence of reliable data on the longevity of cables of either type under conditions experienced on our network, we have assumed the lifespan of our cables to be the same as that specified by the EEA's Asset Health Indicator Guide.

Condition, performance, and risks

Our cable fleet is generally in a good condition. We continue to monitor the trends in cable condition assessment and use the data recorded on premature failures to reassess the remaining population's future performance. The aged-based asset health profile for our distribution cables is shown in Figure 20. All our sub-transmission cables are less than 40 years old.

LV PVC cables are susceptible to water ingress through the PVC and joints to the cable conductor and subsequent corrosion of the aluminium conductor. XLPE insulation is impervious to water, but water may still enter at joints if not adequately sealed.

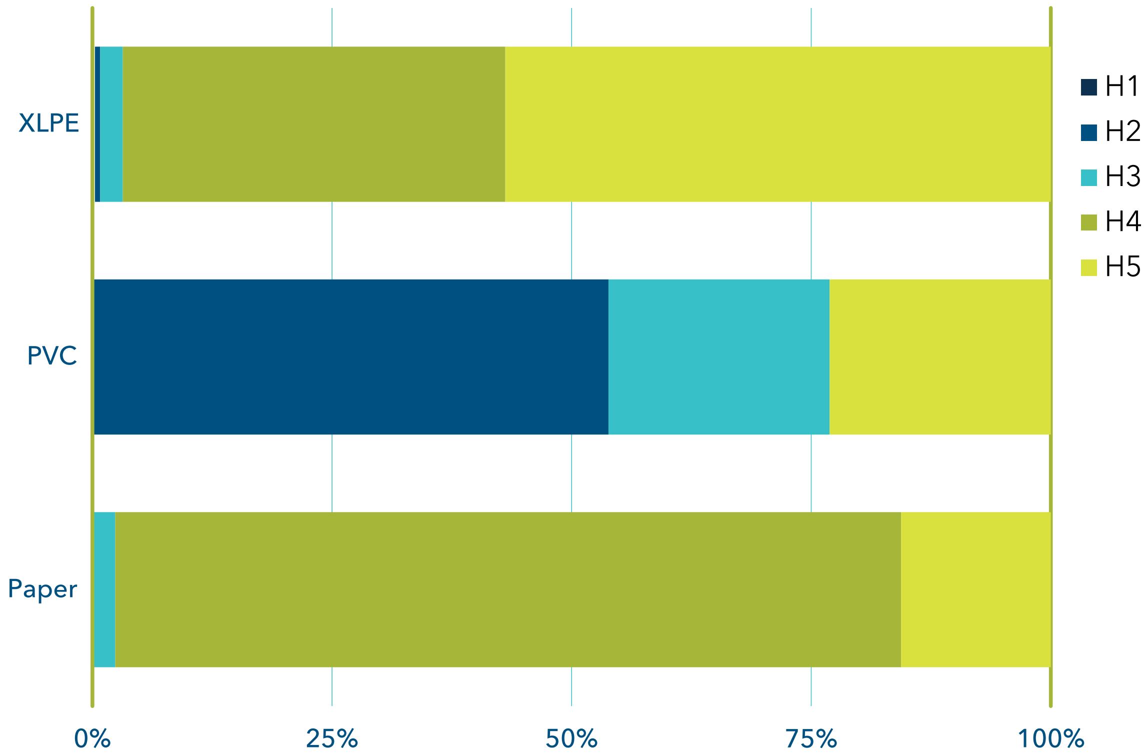


Figure 20: Underground cable asset health as of 2022/23.

The LV cable circuits in the Timaru CBD include main reticulation cables that are buried in the street, feeding a legacy conduit system attached to the fronts of buildings. Our approach is to maintain the LV conduit system above ground unless the building is to be demolished. The cost to replace the LV conduit system with an underground system is relatively high and not always economically justifiable. The seismic status of the CBD buildings may result in either strengthening or replacement of many of these buildings. We will replace the conduit system in stages as these building changes occur.

In the past, major Timaru CBD sub-transmission 11kV cables were offline partial discharge tested every five years to monitor the condition. Recent joint failures to the sub-transmission cables have caused us to increase the VLF partial discharge to a biennial test to determine the change in cable joint condition. Our cable faults tend to be due to joint failure, unfavourable installation conditions, or a foreign body or mechanical interference.

Design and construct

Standardisation assists us in our ongoing management of this asset fleet. Using standard designs and equipment, we can ensure cost-effective capital and maintenance expenditure.

The standard cable sizes we use on our network are listed in Table 14.

Type	Description
Sub-transmission	11kV and 33kV - 1C and 3C, Al: 300 mm2, 400 mm2; 630 mm2, 33kV 1C Al: 1000/1200 mm2.
Distribution	11kV - 1C and 3 C, Al: 95 mm2, 185 mm2, 300 mm2, 400 mm2.
Reticulation	LV neutral screen, 95 mm2, 185 mm2, and 300 mm2.

Table 14: Standard cable sizes.

These cables are aluminium with XLPE insulation. Multicore and single-core cables are used according to the applications. Other conductor sizes may be used, such as when an additional current rating is required.

Operate and maintain

Cables themselves are generally maintenance-free as they are buried for most of their length. We perform inspections and diagnostic testing on above ground components such as terminations every 30 months. We routinely inspect above ground exposed sections of cable and associated terminations to identify any condition degradation (UV is a major cause of degradation).

XLPE cables have a standard life of 45 years, and paper cables a standard life of 70 years. Our 307km of XLPE cable must be replaced at a rate of 7km per annum. We also need to replace our 137km of paper cable at a pace of 2km per year.

For our more important cables (i.e., 33kV and 11kV sub-transmission cables), we have adopted very low frequency (VLF) partial discharge testing as the preferred HV cable test technique to avoid treeing of the XLPE insulation from high voltage direct current (HVDC) test techniques.[5] For the commissioning of cables, we use megger tests. For cable and joint fault-finding, we will use HVDC test equipment on a lower voltage setting to locate the fault to avoid overstressing the healthy cable sections.

LV distribution boxes and link boxes are the largest maintenance item for the LV reticulation, particularly the older painted steel and concrete boxes. The newer boxes made with galvanised steel internal frames and ultra-tough UV stabilised polyethylene plastic covers are relatively low maintenance and consequently are expected to have a longer life.

Renew or dispose

Cable faults most commonly occur due to third party interference such as digging. When cables or their protection have degraded or been damaged, we undertake repairs to avoid a fault occurring. Corrective actions for cables include:

- Replacement of damaged cable termination mechanical protection on poles
- Replacement of cable terminations due to degradation
- Fault repairs due to third-party damage or other cable faults

Spare cable and associated cable jointing equipment are held in our Washdyke depot critical spares store to enable fault repairs to be undertaken.

[5] A damaging process due to partial discharges and progresses through the stressed dielectric insulation, in a path resembling the branches of a tree. Treeing of solid high-voltage cable insulation is a common breakdown mechanism and source of electrical faults in underground power cables.

Our renewal approach for cables is to replace cables based on condition or age.

Cable insulation generally degrades over time, with the largest influences being operating temperatures and exposure to UV (which in turn influences the life of insulation, screens, and cable finishes). Condition assessment, inspections and multiple failures can indicate a cable in poor condition and these cables are replaced.

Planning of cable replacement due to asset health and end of life shall take cognisance of the load requirements for the cable to be replaced. For example, a number of our oldest Timaru CBD cables are reaching their capacity limits owing to their relatively small size compared with our present-day size standards. One or more of these may need to be replaced or supplemented before 2030 due to capacity constraints. New technology uptake may influence the planning of cable replacements in future.

Project: Lucy Box Replacement Programme

Estimated cost: $280,000

Project timing: Annually

In the Timaru CBD many LV supply cables are in the footpaths with distribution and link boxes underground. This older type of link box (Lucy box) was designed to be filled with pitch. Over the years, the pitch has melted and expanded to the extent that operating the links within the box is no longer possible. This presents us with challenges to operate and maintain connected equipment. It also restricts us from configuring the network for planned and unplanned outages.

A programme was commenced in 2014/15 to replace all the subsurface Lucy boxes within the CBD's main LV underground reticulation system with above ground-mounted distribution/link boxes. These box replacements will also allow easier access to the underground and other distribution subs for refurbishment, maintenance, and operation. To date we have completed 21 replacements and have planned five replacements per annum for the first five years of the planning period.

Zone substations

This portfolio includes the following six main fleets, plus other zone substation assets:

- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Buildings
- Load control plant
- Protection relays

The section provides an overview of asset population, age, and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

A zone substation typically takes supply at a voltage level and either steps it up or down to distribution or sub-transmission levels through power transformers. Switching stations, without power transformers, are also included in our fleet of zone substations. Prudent management of these assets is essential to ensure safe and reliable operation.

Portfolio summary

During the planning period we expect to invest $41M in zone substation renewals. This portfolio accounts for 13% of the total renewals budget for the planning period. This investment is needed for:

- New assets due to load growth
- Renewal of assets due to load growth
- Renewal of aged assets
- Managing safety risks

Portfolio objectives

The portfolio objectives for this fleet are given in Table 15 below.

Asset management objective	Portfolio objective
Safety & environment	Safety incorporated in all designs. No lost time incidents due to arc flash faults. Maintain SF_6 register and log gas quantities during maintenance.
Customer service levels	Continual refinement of condition-based maintenance to maximise reliability (SAIDI and SAIFI). Provide mobile substation connection points at all appropriate zone substations.
Cost	Provide cost-effective designs, construction, operation, and disposal.
Community	Ensure fit for purpose infrastructure based on risk mitigation and supply security standard.

Table 15: Zone substation portfolio objectives.

Zone substation transformer

Fleet overview

Zone substation transformers, with capacities ranging from 1 to 40MVA, transform the power supply from one voltage level to another, generally 33/11kV (or 11/33kV), but some are 110/33/11kV and 11/22kV. The zone substation transformers are mostly three-phase units.

Population and age statistics

There are 27 zone substation transformers on our network, of which 20 are 33/11kV units (with three connected as step-up 11/33kV), two are 110/33/11kV and two are 11/22kV. Table 16 summarises our population of transformers by rating. Of the 27 units listed one is a 33/11kV, 5/6.25/9MVA spare and one is part of our 33/11kV, 9MVA mobile substation. We also have two spare 33/11kV transformers.

Rating	Number	% of total
< 5MVA	3	11.1%
≥ 5 and < 9MVA	6	22.2%
≥ 9 and < 20MVA	14	51.86%
≥ 20MVA	4	14.84%
TOTAL	**27**	**100%**

Table 16: Zone substation transformer population.

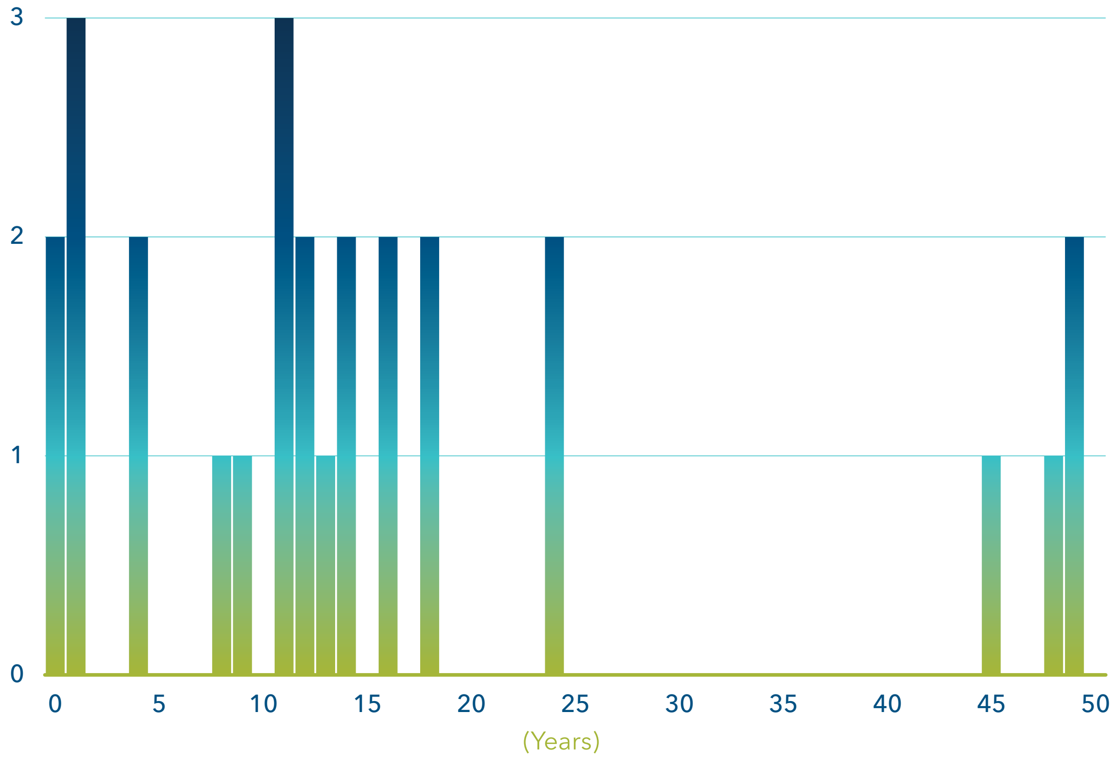


Figure 21: Zone substation transformer age profile in years.

Condition, performance, and risks

The zone substation transformer population is in good condition. The older transformers are typically at sites with low yearly average loads and have been refurbished mid-life to ensure they reach expected service life of at least 50 years. The aged-based asset health profile for power transformers is shown in Figure 22.[6]

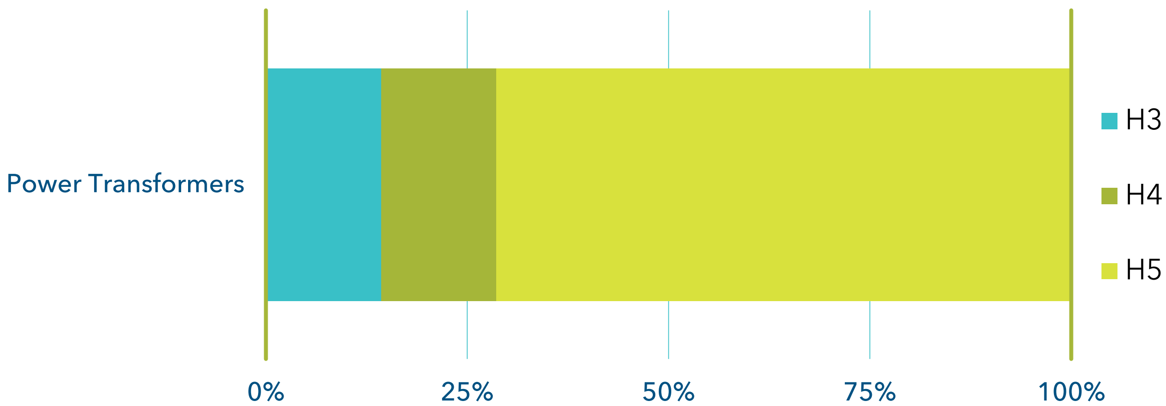


Figure 22: Power transformer asset health as of 2022/23.

Power transformer failures are relatively rare. The main causes are likely to be manufacturing defects or occasional on-load tap changer failures due to mechanical issues.

Design and construct

We have a good design specification for power transformers which, together with design reviews, ensures we get quality assets from our suppliers. Our design specification is based on the AS/NZS 60076 suite of standards. We procure our transformers from a small group of transformer manufacturers.

[6] In accordance with the EEA Asset Health Indicator Guide.

To ensure good operational flexibility across the network we have recently started ordering transformers in standard sizes. However, from time-to-time we have purchased transformers that are not in our standard range.

Standard sizes for 33/11kV transformers are:

- 9/15MVA
- 20MVA
- 19/25MVA

The result of Table 17 having standard sizes is that sometimes a replacement power transformer is larger than the load forecast suggests is required. However, this is offset by the ability to use spares across several units.

We specify all our transformers with low noise emission irrespective of the installation location. This is to ensure the community impact of noise is minimised, even if a transformer is moved to a different substation.

Operate and maintain

Power transformers and their associated ancillaries (such as tap changers) undergo routine inspections and maintenance to ensure their continued safe and reliable operation. These routine tasks are summarised in Table 17.

Maintenance and inspection task	Frequency
General visual inspection of insulating systems, cooling, bushing and insulators, tap changer compartment, foundations, and other ancillaries.	Monthly
Routine planned maintenance: Service dehydrating breathers. External paintwork touch-ups. Automatic voltage regulator operation checks. Buchholz gas check. Acoustic emission, thermal imaging and external partial discharge diagnostic tests, and oil sampling for laboratory dissolved gas analysis tests.	Annually
Routine planned maintenance: transformer, tap-changer, and mechanical/electrical auxiliaries. Insulation and winding resistance tests.	Four yearly and as required by manufacturers' manuals and counters

Table 17: Power transformer maintenance and inspection tasks.

Where possible, we recycle transformers between sites to ensure full utilisation of the life of the transformers. Some units have been refurbished before redeployment to ensure continued satisfactory operation to end of life. The relatively high cost of refurbishment limits the degree of refurbishment and whether it is undertaken. The decision to proceed with a refurbishment is taken on a case-by-case basis.

Mobile substation

Many of our rural zone substations have a single power transformer supply. Some maintenance or planned replacement work requires an outage for the communities supplied by these substations. Over the past few years, it has become increasingly difficult to justify outages due to increased focus on reliability.

Our mobile substation is used to eliminate the need for outages or, in some cases, reduce the extent of the outages. It is also used to improve the reliability of supply during emergencies. Our mobile substation, rated at 9MVA, was procured during AMP period 2014-2015.

Renew or dispose

We have defined a set of triggers for our zone substation assets renewal. These are listed in Table 18.

A power transformer is usually replaced because it is in poor condition, or the required load forecast exceeds its rating. As part of our planning, we ensure that a new power transformer can serve its expected future load at the zone substation. However, significant increase in load due to irrigation has required some transformers to be replaced prior to their conditions reaching a poor classification.

The replaced transformers have usually been recycled around the network and are used at other zone substations. Power transformers have a standard life of 45 years, and we plan to replace five power transformers over the next 10 years.

Most of our power transformer renewals have been triggered by load growth rather than the transformer condition. Zone substation security requirements can be a reason for needing additional transformers.

Power transformer replacements are among the larger projects undertaken within a zone substation. For delivery and cost efficiency, we often coordinate other zone substation works (such as outdoor switchgear replacements) with transformer projects.

Asset	Trigger
Fences and enclosures	Condition-based replacement or maintenance unless costs exceed replacement.
Buildings	Maintenance costs exceed replacement.
Bus work and conductors, 33kV switchgear, transformer, 11kV switchgear	Condition-based replacement or maintenance costs exceed replacement. Load growth. Supply security.
Cable terminations, cable boxes, joint	Condition or age-based replacement.
Batteries and chargers	Age or condition, whichever is sooner.
Instrumentation	Maintenance costs exceed replacement or equipment obsolete, or age limit reached.

Table 18: Triggers for renewal of assets.

To help with long-term forecasting of power transformer replacements we are developing a condition-based asset health model. Asset health indices provide a more accurate assessment of remaining reliable service life than age alone.

Our power transformer asset health model will be based on work by the EEA Asset Health Indicator Guide, influenced by IEC 60599:2015 and CIGRE TB 296, and supported by our experience and asset information. Condition indicators that will be used in the model include dissolved gas analysis (DGA), general condition, age, typical degradation path, bushings condition, external factors (such as coastal salt air), tank condition and known issues.

Zone substation power transformer replacement and renewals for this planning period are detailed in Table 19.

Zone substation transformer	Timing (FY)	Estimate ($'000)
Replace Twizel Village power transformer	2027	1,500
Replace Pleasant Point power transformer	2028	2,200
Replace Unwin Hut power transformer	2029	2,200
Replace Twizel Village power transformer	2030	1,500
Replace Fairlie Zone power transformer	2031	1,500
TOTAL		**8,900**

Table 19: Power transformer replacement/renewal program.

Indoor switchgear

Indoor switchgear comprise individual switchgear panels assembled into a switchboard. These contain CBs, isolation switches, busbars, and associated insulation and metering equipment. They also contain protection and control devices along with their associated current and voltage transformers.

Indoor switchgear is generally considered to be more reliable than outdoor switchgear and also has a smaller footprint than outdoor installations.

33kV zone substation indoor switchgear

There are six 33kV circuit breaker (CB) panels that are indoor type. These were installed in 2011 at the Pareora Zone Substation.

Each 33kV CB panel has two SF_6 insulated chambers, one containing an off-load isolating/earthing switch and the other a vacuum CB.

These six 33kV indoor vacuum/SF_6 CB panels have a manufacturer's assurance of 40 years maintenance free operation. Routine monitoring and inspections are only required for the life of the switchgear.

11kV zone substation indoor switchgear

There are 163 11kV indoor CBs within 16 indoor 11kV switchboards in our zone substations. The majority of our 11kV zone substation indoor CBs are vacuum type (VCBs), and 16 are of the bulk oil variety. The vacuum type CBs are used for all new installations and where bulk oil CBs are being replaced.

We only have two zone substations left with bulk oil switchboards at Tekapō and Twizel Village Substations. The Twizel Village Substation 11kV switchboard will be replaced during 2023/24.

Population and age statistics

Table 20 summarises our indoor switchgear population by type and number of CBs and switchboards.

Voltage	Air	Solid Dielectric	SF_6	Oil	Total
11kV	145	2	0	16	163
33kV	0	1	6	0	7
TOTAL	**145**	**3**	**6**	**16**	**170**

Table 20: Indoor switchgear population by operating voltage rating and insulating medium.

Table 21 summarises our indoor switchgear population by make and model. Figure 25 show the age profiles for indoor type 33kV and 11kV CBs. Our 33kV CBs are 10 years old or less. The oldest CBs in our fleet are in the Twizel Village substation with an age of 71 years. The next oldest CBs are located at Tekapō Zone Substation and are 38 years old.

Type	Make	Model	Voltage	Number	% of total
Metalclad	RPS	LMVP	11kV	123	72.4%
	Toshiba	VK10M25	11kV	17	10.0%
	Tamco	VCB	11kV	5	2.9%
	South Wales	D6XD	11kV	7	4.1%
	Thomson Houston	BTH	11kV	8	4.7%
Metal-enclosed	Areva	GHA	33kV	6	3.5%
Ring Main Unit	Long & Crawford	L&C	11kV	1	0.6%
Viper™ Recloser	G&W	Viper-S	11kV	2	1.2%
Viper™ Recloser	G&W	Viper-S	33kV	1	0.6%
TOTAL				**170**	**100%**

Table 21: Indoor switchgear population by make and model.

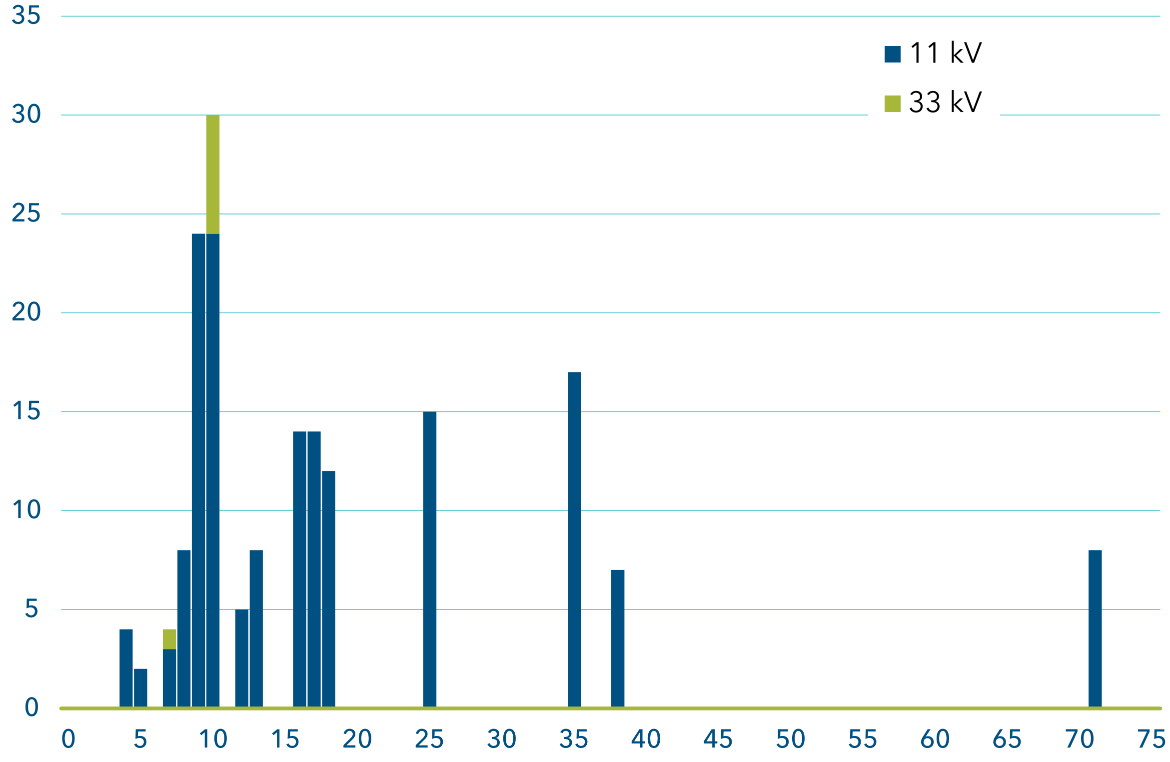


Figure 23: Indoor switchgear age profile in years.

Condition, performance, and risks

Indoor switchgear asset health

For indoor switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely, and the switchgear should be replaced. The switchgear condition is primarily evaluated using asset age, typically expected life and condition assessment.

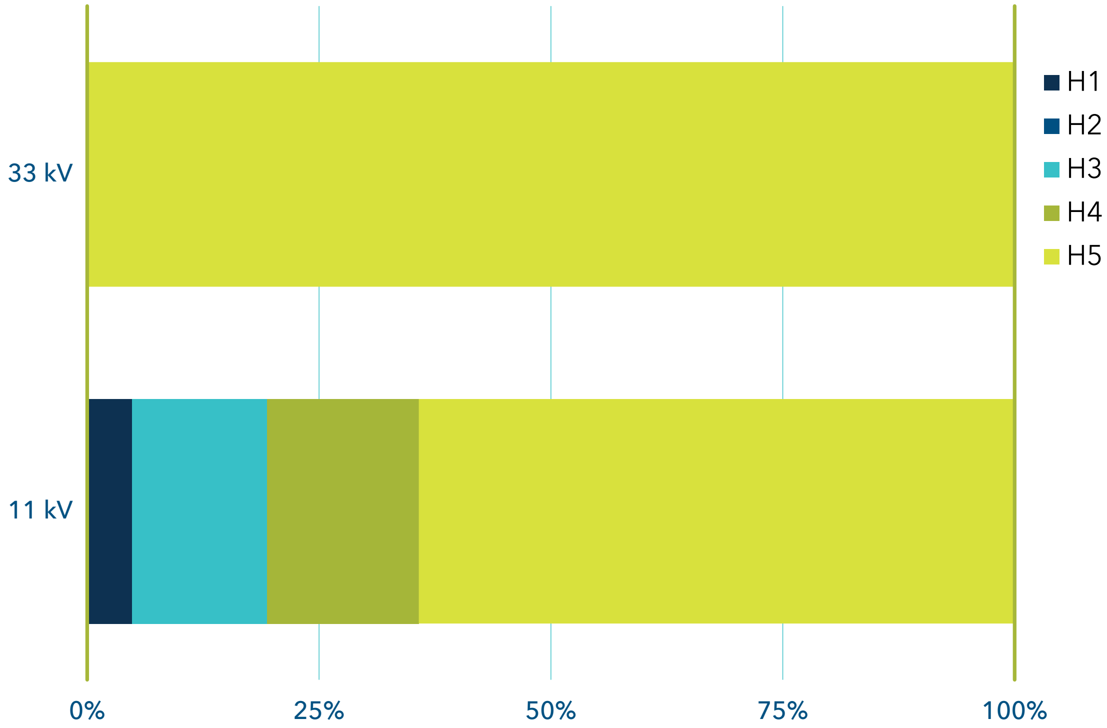


Figure 24: Indoor switchgear asset health as 2022/23.

The aged-based asset health profile for indoor switchgear is shown in Figure 24. About 10% of our indoor switchgear requires replacement over the next 10 years.

Arc flash risk

Arc flash risk is a safety concern that is considered for our indoor switchgear fleet. Arc flash containment and detection is an integral part of our indoor switchgear specifications. Assessments are undertaken as part of our safety in design process to determine risk levels.

We mitigate this risk through one of three approaches:

- Switching is carried out remotely while ensuring the switchroom is clear of personnel
- Ensuring personnel working close to the switchboard wear appropriate arc flash rated personal protective equipment (PPE)
- Remove the entire switchboard from service to perform maintenance

These solutions do not completely eliminate arc flash risks.

All newly installed switchboards have arc flash detection systems, arc containment and venting. We have installed various arc flash retrofits (including blast-proof doors, arc flash detection systems and arc venting) on several existing switchboards to mitigate arc flash risk. We are continually evaluating arc-flash mitigation options on our remaining switchboards that are classified as relatively high risk to safety due to arc-flash risks.

Before a new type of switchgear can be used on the network, it must undergo a detailed evaluation process as part of our safety in design (SiD) process to ensure the equipment is fit for purpose on our network.

Operate and maintain

Indoor switchgear undergoes routine inspections and maintenance to ensure their continued safe and reliable operation. Our various routine maintenance tasks are summarised in Table 22. The detailed regime for each asset is set out in our maintenance standard.

Maintenance and inspection task	Frequency
General visual inspection of CBs, cabinets, and panels.	Monthly
Operational tests on CBs not operated in last 12 months. Condition-test switchgear including thermal, PD and acoustic emission scan.	Annually
Insulation, contact resistance and operational tests. Service of oil CBs. Mechanical checks. SF_6 gas pressure checks.	Four yearly
Vacuum circuit breaker diagnostic tests (for example, HV withstand).	As required
Switchboard partial discharge test.	As required

Table 22: Indoor switchgear maintenance and inspection tasks.

Renew or dispose

Indoor switchgear renewal decisions are based upon several factors, as detailed in Table 23.

Replacement/renewal trigger	Trigger threshold
Condition	Systemic faults or failure of components. Availability of spare parts or age.
Rating	Capacity is depleted through load growth.
Reliability or safety	Improve on arc flash risk. Test results inconsistent and not within maximum tolerances.
Economical	Maintenance costs become uneconomical.

Table 23: Summary of indoor switchgear renewal approach.

New zone substation projects typically use indoor switchgear because it provides better value with regard to performance and whole-of-life cost. For urban substations, switchgear is installed in buildings that visually integrate into the surrounding neighbourhood to minimise visual impact.

Criticality and resilience

In addition to the renewal triggers as listed in Table 23, we consider the criticality of the zone substation and the resilience required when we determine the optimum time for replacement.

Renewals forecasting

Only the switchboard at our Twizel Village Substation is beyond the maximum practical life of 60 years as defined in the EEA Asset Health Indicator Guide. It is also the only switchboard beyond the ODV life of 40 years. Applying the replacement criteria as described above, Table 24 details our replacement programme for the planning period.

The project planned for 2026/27 at our Hunt Street Substation, will not comprise a whole new switchboard but rather only the replacement of the circuit breaker trucks.

Zone substation	Timing (FY)	Estimate ($'000)
Twizel Village	2023/24	5,000
Tekapō	2027/28	2,500
Hunt Street	2026/27	2,500
TOTAL		**10,000**

Table 24: Indoor switchgear replacement program.

Outdoor switchgear

Our zone substations outdoor switchgear fleet comprises several asset types including outdoor CBs, air break, and load break switches, fuses, links, and reclosers.

Outdoor switchgear is primarily used to control, protect, and isolate electrical circuits in the same manner as indoor switchgear. It de-energises equipment and provides isolation points so our contractors can access equipment to carry out maintenance or emergency repairs.

Most of our zone substation outdoor switchgear assets are either 11kV or 33kV rated with a small historical amount of 22kV and recently installed 110kV switchgear. The following table summarises our population of outdoor CBs by operating voltage and type.

Operating Voltage	CB	Recloser	RMU-CB	Total
110kV	2	-	-	2
33kV	22	9	1	32
22kV	2	2	-	4
11kV	14	8	6	28
TOTAL	**40**	**19**	**7**	**66**

Table 25: Outdoor circuit breaker population by voltage rating and type.

We have 40 outdoor CBs installed at our zone substations and switching stations. The interrupting media comprises oil, vacuum and SF_6 while the insulating medium is either oil, solid dielectric, or SF_6.

Most outdoor zone substation CBs are oil or vacuum in oil (20.0%), with the remainder being SF_6 (42.5%) and vacuum (37.5%) interrupter based (in air or solid dielectric).

Table 26 summarises our population of outdoor CBs also broken down by interrupter type.

Operating Voltage	Oil	Vacuum	SF_6	Total
110kV	-	-	2	2
33kV	8	5	9	22
22kV	-	2	-	2
11kV	-	8	6	14
TOTAL	**8**	**15**	**17**	**40**

Table 26: Outdoor circuit breaker population by voltage rating and interrupting media.

Population and age statistics

There are five 110kV rated SF_6 outdoor CBs on our network. Three of them are currently operated at 33kV.

There are 23, 33kV outdoor CBs and reclosers (switchgear) within our zone substations majority of which are oil and vacuum in oil while recent 33kV switchgear are SF_6 insulated. 33kV CBs typically carry a function of protecting power transformers and/or sub-transmission lines.

There are fourteen 11kV outdoor CBs and reclosers in our zone substations as the majority of our 11kV zone substation switchgear comprises of indoor installations.

Figure 27 show the age profile for all zone substation outdoor switchgear. This also includes air-break switches, links, and fuse links. Since these additional types of switchgear is not as critical as CBs, the age profile and asset health profile should be considered with this fact in mind. The majority of switchgear older than 40 years of age are ABS and links. Only the Pleasant Point and Twizel Village Zone Substations have CBs that are 40 years or older.

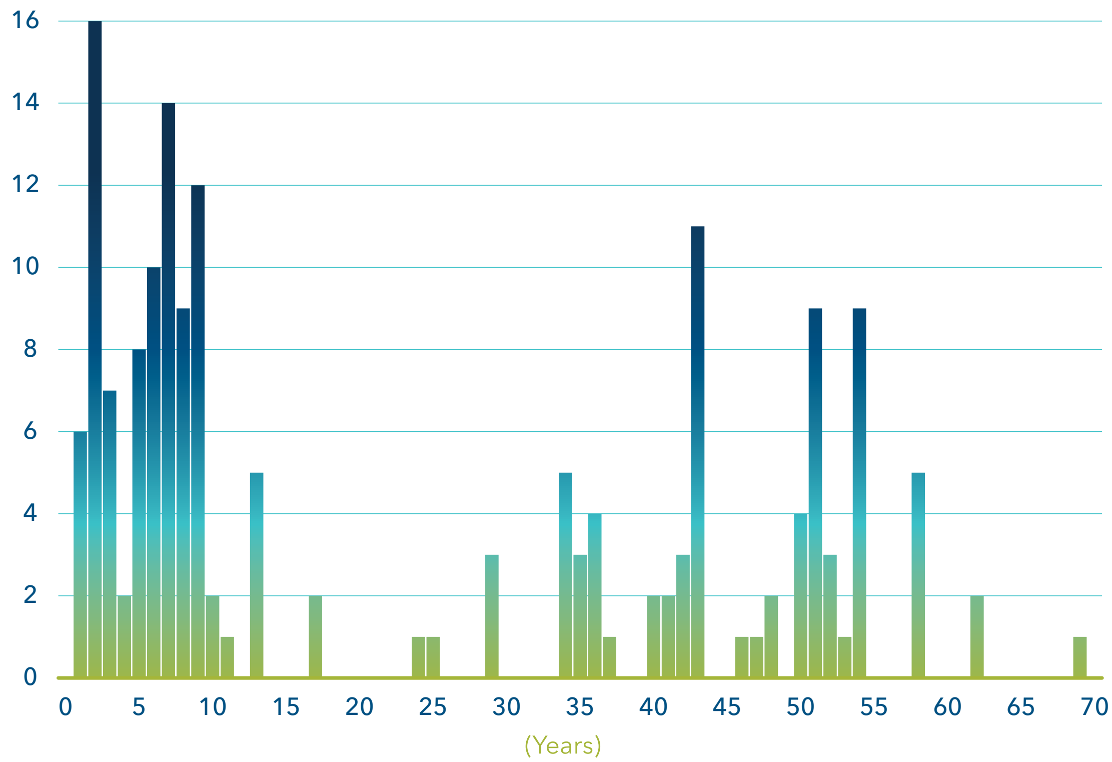


Figure 25: Zone substation outdoor switchgear combined age profile in years.

We generally expect outdoor switchgear assets to require replacement at an age of 45 to 55 years. Assets close to their ODV expected life are monitored closely and replacements will be based on condition. A large number of air break switches (ABS), load break switches (LBS), links and other outdoor switchgear have been maintained and refurbished over the past decade (i.e., ABS/LBS mechanism maintained, and insulators replaced to extend asset life.

Condition, performance, and risks

Oil-based CBs carry additional risks compared to their modern equivalents. A higher frequency of operations and energy of switching increases the likelihood of failure. To minimise this failure risk, oil circuit breakers (OCBs) are serviced after they have performed a specified number of switching operations. The number is based on the type of circuit breaker and the fault current breaking energy.

For outdoor switchgear, we define end-of-life as when the asset can no longer be relied upon to operate reliably and safely. The switchgear condition is primarily evaluated using asset age, typical expected life, and condition assessment.

The aged based asset health profile for outdoor switchgear is shown in Figure 26. It is important to note that the health level H1 comprises mainly ABS which are maintained as part of the four-yearly zone substation maintenance program.[7] They are located at our Timaru, Twizel, Tekapō, and Temuka Substations. The AHI is not reflective of outdoor CBs.[8]

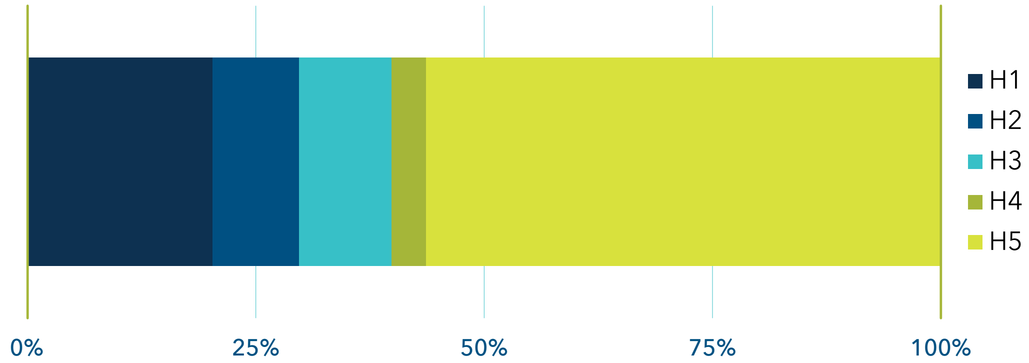


Figure 26: Outdoor switchgear asset health as of 2022/23.

Design and construct

For outdoor 33kV CBs replacement, our current standard asset is a live tank SF_6 insulated unit. SF_6 CBs are the current industry standard for HV outdoor applications. However, we are continually monitoring developments in the industry to ensure the best solution for the network is utilised.

Operate and maintain

Outdoor switchgear undergoes routine maintenance to ensure safe and reliable operation. We undertake routine maintenance on OCBs based on the number and severity of CB operations for fault current clearance to mitigate against failure modes associated with excess duty.

Our various routine maintenance tasks are summarised in Table 27. The detailed regime for each asset is set out in our Outdoor Switchgear Maintenance Standard.

Maintenance and inspection task	Frequency
General visual inspection of CBs, ABSs and reclosers.	Monthly
Operational tests on CBs. Condition-test CBs including thermal, PD and acoustic emission scan.	Biennially
Circuit breaker insulation, contact resistance and operational tests. Service of OCBs. Mechanical checks. ABS thermal scan. Recloser thermal and oil insulation tests.	Four yearly.
ABS service of contacts and mechanism.	As required.
Vacuum and SF_6 recloser checks and insulation tests.	As required.
Replace oil (if relevant). Contacts checked and resistance measured.	Operations based.

Table 27: Outdoor switchgear maintenance and inspection tasks.

Outdoor switchgear requires more routine and corrective maintenance than indoor switchgear because its components are exposed to outdoor environmental conditions.

[7] In accordance with the EEA Asset Health Indicator Guide.
[8] The AHI for outdoor CBs is depicted in schedule 12(a) in Appendix D

Renew or dispose

Our approach is to replace outdoor CBs and other outdoor switchgear equipment based on condition. We aim to avoid outdoor switchgear failure. Network consequences can be high, and failure modes can be explosive, particularly with oil-filled switchgear.

Although unlikely, OCB failures can result in explosions and fire. OCBs are mainly 33kV rated and represented in the higher age group of our outdoor switchgear. OCBs will be phased out over time and replaced by either vacuum or SF_6 based CBs. VCBs are preferred over SF_6 as they have a lower carbon footprint, but an existing substation's real estate area may necessitate the use of SF_6 breakers because they are more compact.

Our in-service OCBs are generally in good condition with no partial discharge issues detected to date, but they require the same maintenance for the oil and contacts. There is no urgency to replace them, as their condition and the maintenance costs alone do not justify replacement.

Replacement/renewal trigger	Trigger threshold
Condition	Systemic faults or failure of components. Availability of spare parts or age.
Rating	Capacity is depleted through load growth.
Reliability or Safety.	Improve on arc flash risk. Test results inconsistent and not within maximum tolerances.
Economical	Maintenance costs become uneconomical.

Table 28: Outdoor switchgear renewal approach.

Within the present 10-year planning period, OCBs are more likely to be replaced as a result of other associated assets needing replacing or due to load growth triggering a replacement of the transformer, replacement of the whole substation, or an upgrade to the protection schemes requiring more modern CBs.

Of the remaining outdoor CBs, only the older pole mounted 33kV reclosers are likely to be replaced within the planning period.

Our renewals quantity forecast for longer-term outdoor switchgear uses useable age as a proxy for condition. Older switchgear is more likely to be in poor condition because of exposure to corrosive environments for longer periods. Their mechanical components are also likely to have more wear and tear. We replaced the older Twizel Zone Substation and Pleasant Point 33kV outdoor CBs in 2023. The planned construction of a second 33kV supply point at Timaru GXP will remove the need to replace the 33kV outdoor CBs at Timaru GXP.

Zone substation protection relay

Protection relays are installed in zone substations to detect and interrupt electrical faults while minimising the number of connections that are affected.

Our network has a mixture of electromechanical, static, and numerical protection relays. Most zone substations have numerical protection relays installed. These are the industry standard and allow for the implementation of the latest control and protection schemes. Numerical relays can be connected to our SCADA system, thereby providing timely notice of system disturbances that are detected. The communication function is also utilised in combination with the relay's self-checking algorithms to provide notice if the relay detects any internal failures.

Population and age statistics

Table 29 below details the type, number, and proportion of protection relays on our network.

Relay Type	Quantity	% of total
Electromechanical	41	9%
Static	29	6%
Digital	377	85%
TOTAL	**447**	**100%**

Table 29: Zone substation protection relay population.

Our protection relay fleet is relatively modern with 98% of all relays installed in the last 20 years. The use of modern relays allows for the implementation of advanced functions that provide superior protection of equipment and reduce nuisance outages for customers.

Figure 27 shows a summary of our protection relay population based on age and quantity. The useful life of the various types of relays we have on our network is detailed in Table 30.

Relay Type	Useful Life (Years)
Digital	25
Static	25
Electromechanical	30-40

Table 30: Protection relay useful life.

We have two electromechanical relays that are 51 years old at our Twizel Village Zone Substation and another two at our Timaru Zone Substation that are 42 years old. The refurbishment of the Twizel Village Zone Substation will be completed in 2023/24, at which time these relays will be replaced. The Timaru Zone Substation is planned to be refurbished within the first five years of the planning period at which time these relays will be replaced. These relays are still subject to our four-yearly zone substation protection testing and maintenance regime.

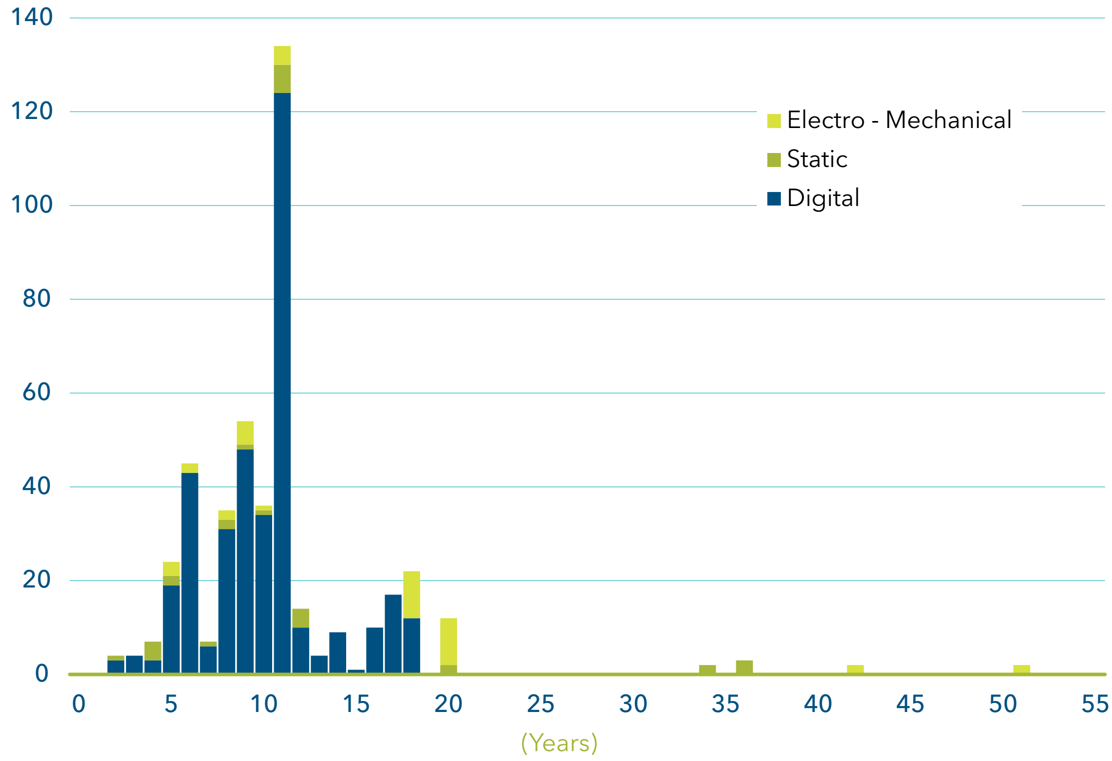


Figure 27: Zone substation protection relays age profile in years.

Operate and maintain

Digital relays can integrate the functionality of several electromechanical relays into one compact unit. Complex protection and control functions that were not previously available are configurable, and most digital protection relays on our network are connected for remote control and interrogation. Digital relays have a dominant failure mode associated with the degradation of capacitors in their power supply circuitry. Digital relays installed in the network are expected to have an operating life of approximately 25 years, at the end of this period, the device/s are replaced.

Our digital relays are all self-monitoring and are only required to be tested once every 10 years. However, since the protection system measuring circuits and the trip circuits, including the circuit breaker trips, are required to be tested every four years, we have decided to also test all the protection relays as part of this maintenance schedule.

Condition, performance, and risks

Protection relay age is one indicator of its reliability. Electromechanical, static, and digital relays are all affected differently with age. Literature suggests that the life expectancy of electromechanical relays is around 30 to 40 years. Experience has shown that some electromechanical relays have been able to function reliably for over 50 years. After this time, the unit is typically not worth repairing, and replacement with a modern digital relay is recommended where this is appropriate.

Condition assessment of protection relays is managed through routine testing and, where available, continuous online self-monitoring. All relays currently installed in our zone substations meet the minimum requirements for operating time.

Most zone substations provide climatic controls to limit the temperature/humidity extremes that the relays are exposed to. This assists in extending the life of all components and the relay itself. The age-based asset health profile for our protection relays is shown in Figure 28.

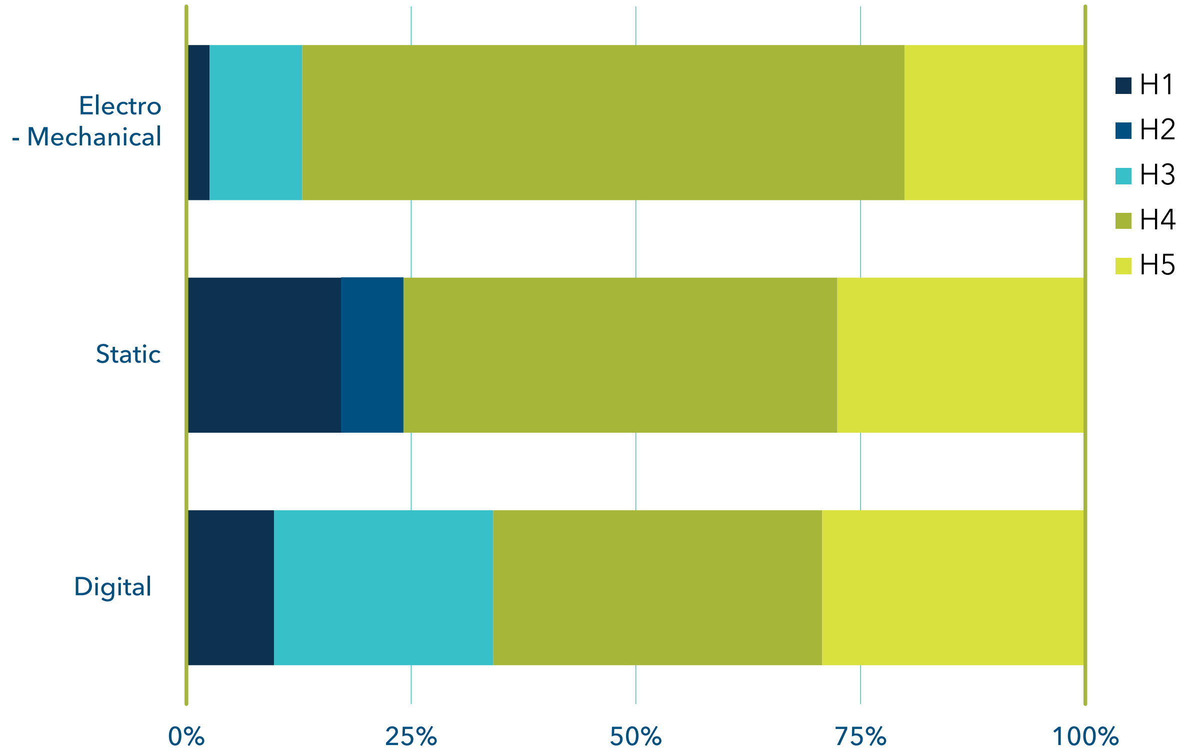


Figure 28: Protection relay asset health as of 2022/23.

Installation of modern digital relays allows for the implementation of higher complexity protection schemes that can provide faster operation for equipment faults and reduce the probability of nuisance trips. In many cases, a safety improvement is also possible. An example of this is the arc-flash detection capable relays that are installed in zone substation switchboards.

Renew or dispose

We are continually assessing protection relay requirements, industry best practices and available network data to evaluate possible future investments in our zone substation protection relays.

The remaining relays that are over 30 years old will be replaced within the first half of the planning period. All replaced relays shall be disposed of unless they serve a purpose as a spare.

The vast majority (94%) of protection devices installed in our network are expected to function reliably, with only routine maintenance being required over the next 10 years.

Zone substation bulk metering

We have digital revenue and check meters installed in some zone substations to either provide revenue metering to our customers, supplied at 11kV, or as check meters. The Metering Equipment Providers (MEPs) look at the revenue meters, and these meters are not usually connected to our SCADA system. The check meters are connected to our SCADA system so that these can be monitored remotely.

Population and age statistics

We have eight digital revenue and six digital check meters installed. Table 32 summarises our population of zone substation metering equipment, and Figure 29 shows the age profile of the revenue meters.

Age (Years)	Number	% of total
5 to ≤ 10	2	25%
11 to ≤ 15	2	25%
16 to ≤ 20	4	50%
TOTAL	**8**	**100%**

Table 32: Zone substation revenue metering population.

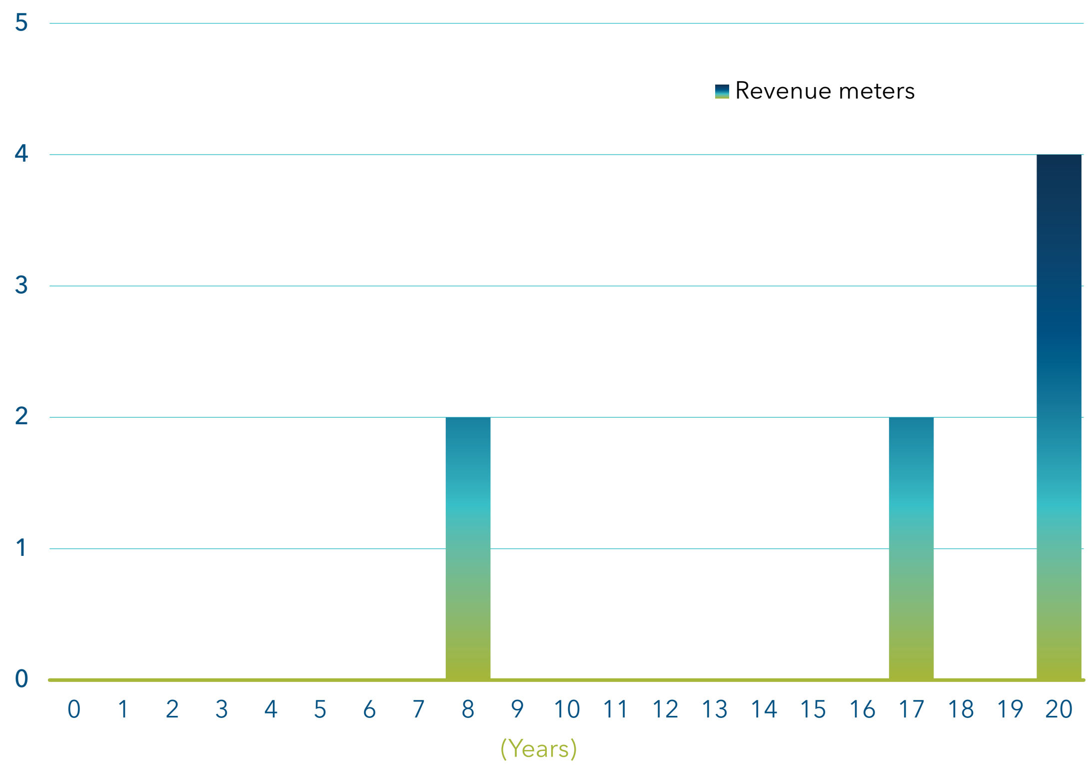


Figure 29: Zone substation-based revenue meter age profile in years.

Condition, performance, and risks

The revenue and check meters are not critical in maintaining our supply to customers. There are also no safety and environmental considerations associated with revenue meters. The age-based asset health profile for our based revenue meters is shown in Figure 30.

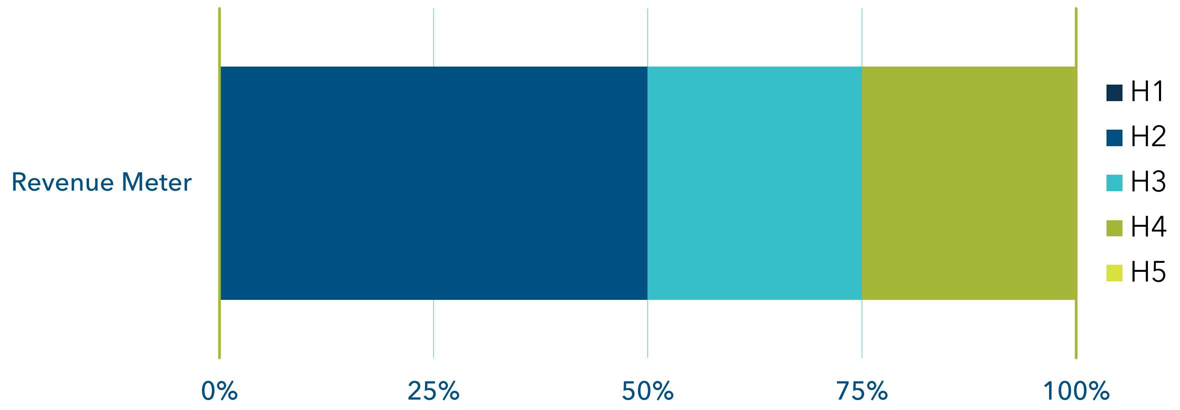


Figure 30: Zone substation-based revenue meter asset health as of 2022/23.

Design and construct

We work together with the MEPs to apply, maintain, and improve their capability to design, test and install metering technology within our network. It is the MEPs responsibility to ensure that the revenue meters are calibrated and that the metering installations are certified.

Operate and maintain

The maintenance requirements for revenue meters are prescribed by the Code and are the responsibility of the MEPs. The MEP will handle the failure of a revenue meter, and we will replace faulty meters. We enable the MEPs to conduct annual inspections and certification of the revenue meters and ensure their continued safe and reliable operation.

Renew or dispose

The eight revenue meters are considered to have a life expectancy of 20 years. The four revenue meters at Clandeboye 1 Substation (CD1) are 17 years old and will be replaced in 2023/24 and 2024/25. The two revenue meters at Clandeboye 2 Substation (CD2) will be replaced in 2023/24. Two of the revenue meters at CD1 are on the incoming feeders, while the other two are on feeders external to our network.

For Fonterra Clandeboye to be billed correctly, it is necessary to subtract the meter readings for the two external feeders from the meter readings for the two incomer revenue meters. This metering scheme is not usually allowed, though we have a 10-year dispensation to operate the subtraction scheme. This dispensation expires on 30 June 2025. We will not be allowed to continue the subtraction scheme once the revenue meters are upgraded. We will engage an MEP to fit new revenue meters and associated Current Transformers (CTs) on nine Clandeboye feeders in 2023/24 and 2024/25, at an expected total cost of $300k.

Buildings fleet management

Zone substation buildings mainly house protection, SCADA, communications, and indoor switchgear equipment and, in some cases, load control injection plants. Zone substation sites need to be secure. Buildings and equipment are well secured for earthquake exposure and are designed to minimise the risk of fire, vermin, or vandalism.

We undertook a survey of our existing zone substation buildings following the Christchurch earthquakes to check their condition. This inspection indicated that our buildings were not damaged beyond their structural design. Over this planning period we will increase our understanding of our risk exposure to a potential Alpine Fault magnitude 8 earthquake (AF8).

Population and age statistics

We have 25 buildings located within our zone substations. These are constructed of various materials, including mainly steel-reinforced concrete, steel insulated sandwich panel and some timber frame.

Age (Years)	Number	% of total
≤10	5	20%
11 to ≤20	8	32%
21 to ≤30	3	12%
31 to ≤40	1	4%
41 to ≤50	4	16%
51 to ≤60	1	4%
61 to ≤70	3	12%
TOTAL	**25**	**100%**

Table 33: Zone substation building population.

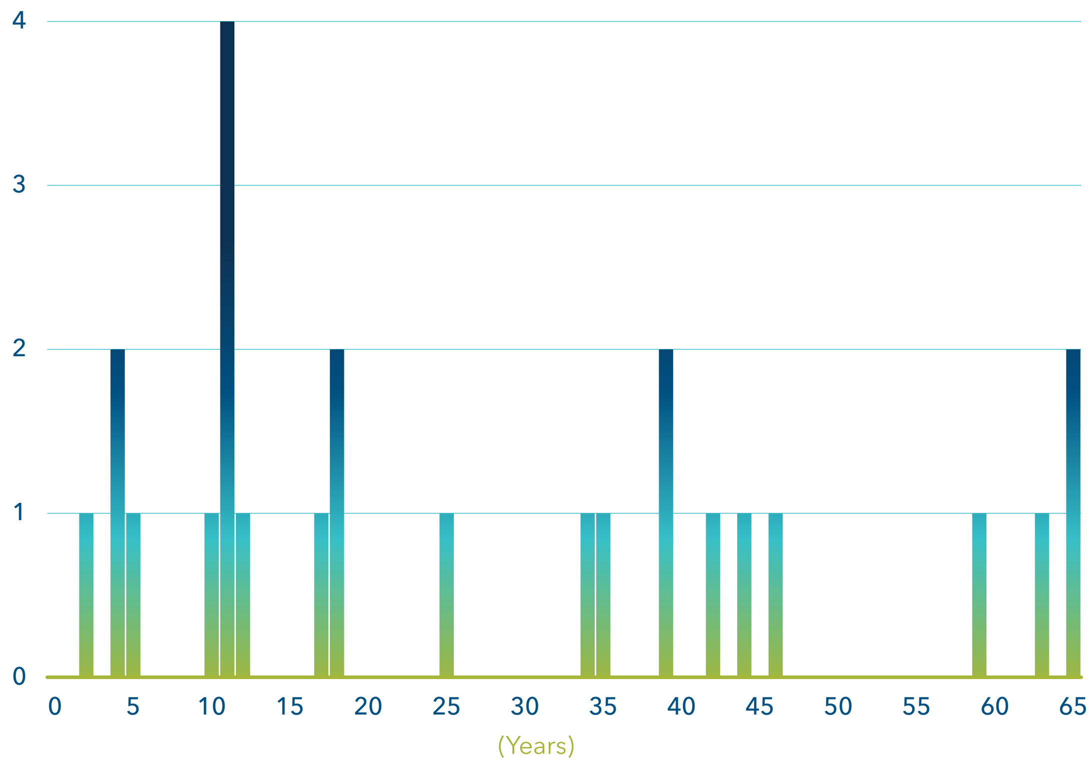


Figure 31: Zone substation buildings age profile in years.

Condition, performance, and risks

The condition of our zone substation buildings is generally good to excellent with a few legacy buildings and a significant number of new and refurbished buildings resulting from recent growth-driven zone substation projects.

We have reviewed the condition of all our zone substation buildings and have been maintaining, refurbishing, and replacing these assets as required.

Three of our ripple plant buildings are of older timber frame construction and are generally sound but require maintenance. Of these, one was completely refurbished for re-use in 2017 for a new replacement ripple plant; another hasn't housed a ripple plant for many years and is surplus to requirements, and the last has recently had its galvanised steel roof replaced. All three are legacy buildings whose exterior walls are partially clad with fibrous (asbestos) cement panels and partially with exterior ply (for seismic strengthening) and painted. If the asbestos panels are not disturbed and are maintained in a painted state, the asbestos will not be a hazard. Therefore, these buildings do not need to be refurbished or replaced because of asbestos. Should any future work be required that might disturb the asbestos, we will arrange for the removal of the asbestos from that building by a suitably qualified contractor.

Design and construct

We design our zone substation buildings to be functional and to comply with the required seismic strength. The layout of our newer buildings has been standardised in terms of functionality. The size varies to suit the various substations. We also consider the aesthetics of the building where applicable.

All our newer buildings have a brick with steel roof construction except for small buildings, which are made with steel sandwich panels (i.e., portable style buildings). For new ripple plant buildings, we use purpose fitted and painted shipping containers.

Operate and maintain

We routinely inspect our zone substation buildings to ensure they remain fit for purpose, and any remedial maintenance work is scheduled as required. General visual inspections and housekeeping are performed monthly, with more detailed inspections undertaken annually. Ensuring our buildings are secure is essential to prevent unauthorised access.

Maintenance and inspection task	Frequency
General visual inspections and housekeeping.	Monthly
More detailed inspections.	Annually

Table 34: Zone substation building maintenance and inspection tasks.

Renew or dispose

As discussed above, we will be undertaking specific maintenance to ensure our buildings are safe and able to assist the equipment they house to maintain a reliable supply. There are two of our older ripple plant buildings that will be replaced or refurbished during the planning period.

Two of our smaller legacy switch room buildings at Twizel and Unwin Hut will be replaced with new buildings or portacom-type structures during the planning period. In addition, our Hunt Street switching station building will be risk assessed and possible alterations made to replace the glazed parts with more suitable cladding.

Load control injection plant

Load control systems are used to manage the load profiles of customers with controllable loads (for example, hot water or space heating) and shed load, such as irrigation, when required.

If configured well, load control systems effectively reduce demand at peak times by deferring non-time-critical power usage. Benefits of load control include more predictable peak demand and allowing us to defer distribution capacity increases. Wider benefits include a reduced need for peaking generation plants and transmission deferral.

Population and age statistics

We currently operate load control injection plants on our network, comprising both modern and aged equipment. Table 35 summarises our load control injection plant population by type.

Type	Plant	% of total
Modern electronic plant.	6	86%
Legacy rotary plant.	1	14%
TOTAL	**7**	**100%**

Table 35: Zone substation load control injection plant population.

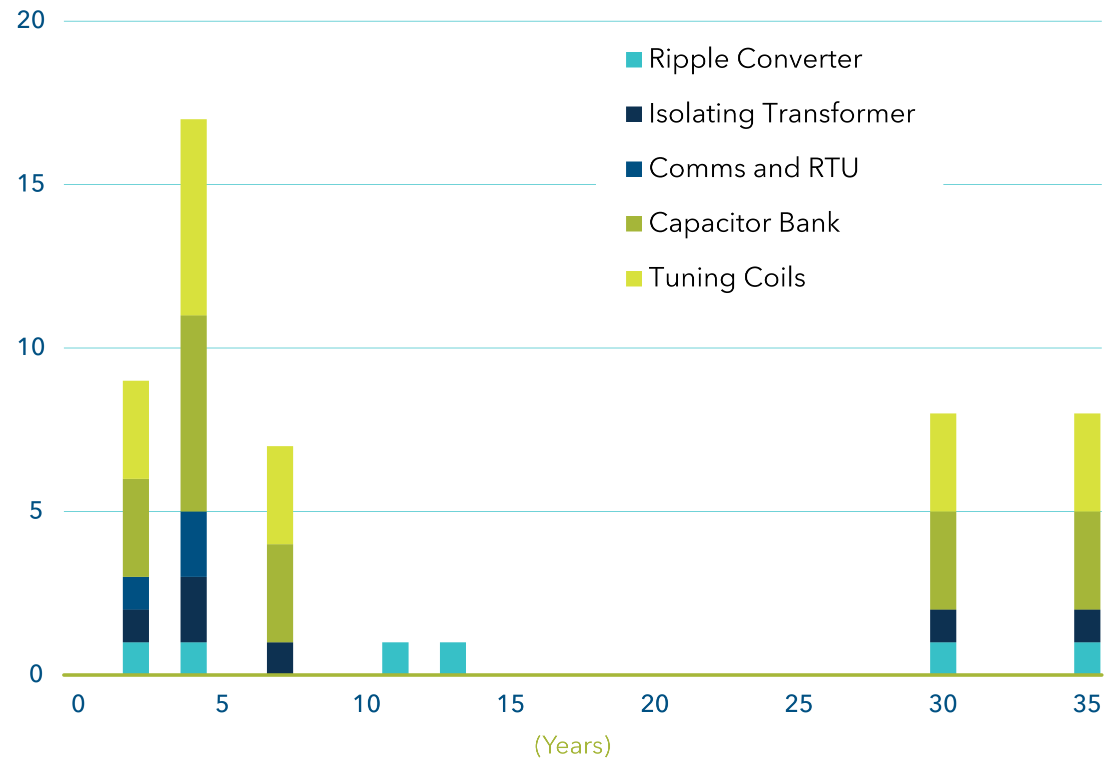


Figure 32: Zone substation load control injection plant age profile in years.

Condition, performance, and risks

A new ripple plant was commissioned at our Albury Zone Substation in 2017 after the building was refurbished.

The Tekapō legacy rotary load control plant is considered obsolete. However, it is still performing well. It controls a relatively small number of ICPs in its area with a limited load that can be shed. It is proposed that when it finally needs to be decommissioned, the load control will be undertaken by time clocks in new smart meters and associated programmable ripple relays. This strategy will, however, be reviewed on an annual basis to ensure we meet our network growth, operational and retailer commitments.

The age-based asset health profile for our ripple plants is shown in Figure 33.

Three of our load control injection plants have relatively new Remote Terminal Units (RTUs), which are performing well. The other two ripple plants have old Conitel RTUs, which are close to 30 years old. They have performed well to date and are due for replacement. In addition, they are proving a challenge for connection to our SCADA. The Conitel RTU at the Timaru substation was replaced in 2017. The second Conitel RTU on the legacy plant at the Tekapō substation may not be replaced since the plant will be allowed to reach its end-of-life and will then be decommissioned. This strategy will be reviewed on an annual basis.

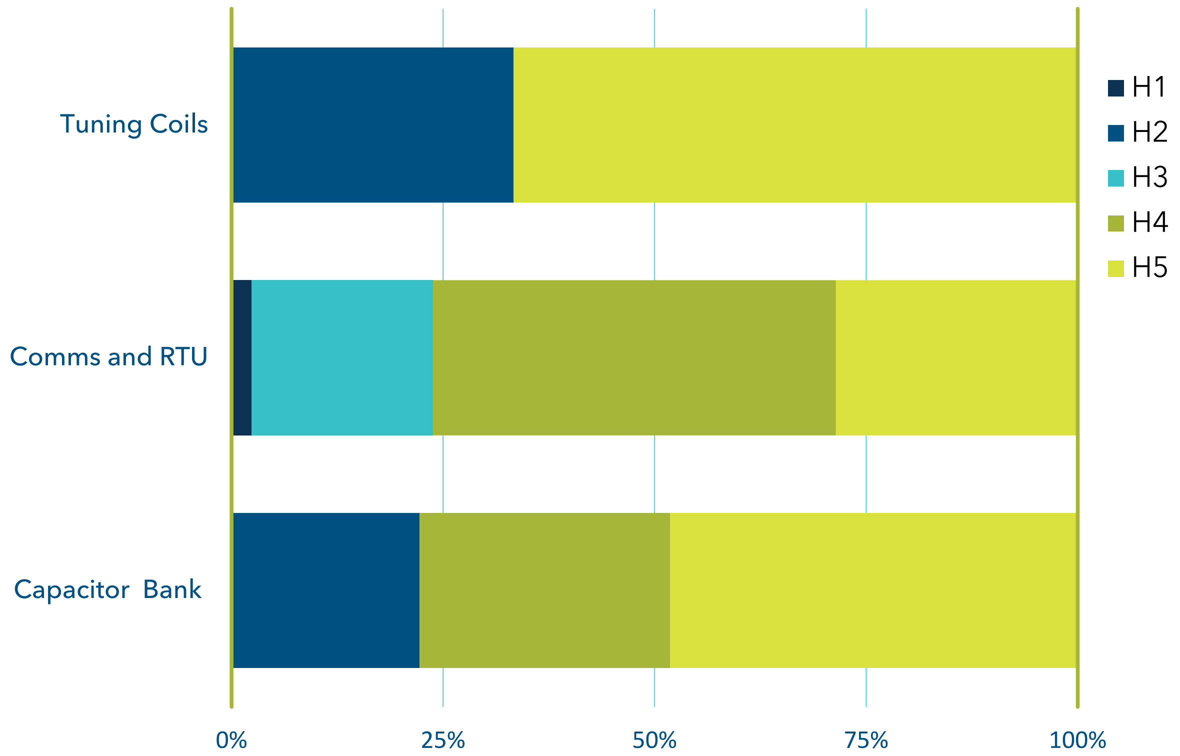


Figure 33: Load control plant asset health as of 2022/23.

Design and construct

Our standard for current and future plant is the DECABIT channel command format. The DECABIT standard has proven to be the most reliable and error-free standard and is widely used in New Zealand.

Operate and maintain

Due to the specialist nature of load control plant, we have a backup and service support contract that covers our modern static installations. This contract covers annual inspections, holding of critical spares and after-hours emergency support.

Maintenance and inspection task	Frequency
General visual inspection of the plant. Operational tests.	Annually
Diagnostic tests, such as resonant frequency checks, signal injection levels and insulation resistance.	Five yearly

Table 36: Load control plant maintenance and inspection tasks.

Renew or dispose

The legacy load control plant installation uses a higher ripple frequency of 500 Hz, whereas our modern plants use 317Hz. Obtaining spares and manufacturer support is very difficult, so when it eventually fails, it will be decommissioned in favour of the smart meters time clock. Apart from this legacy plant, we will renew the ripple plants to maintain the functionality of the existing fleet. Our load control plant replacement/renewal programme for the planning period is detailed in Table 37.

Unit / Location	Timing (FY)	Estimate ($'000)
Studholme Substation	2026	150
Bells Bond Substation	2026	250
TOTAL		**400**

Table 37: Load control plant replacement.

Other zone substation asset

The other zone substation asset fleet comprises outdoor bus systems, fences and grounds, earthing, communications masts, lightning protection systems, security/access control systems and fire systems.

Outdoor bus systems are switchyard structures comprising pole structures, HV busbars and conductors, associated primary clamps and accessories, support posts and insulators.

The risk of a lightning strike to zone substation HV equipment in South Canterbury is very low, most of our sites however are designed with lightning protection systems to reduce the impact of a lightning strike on HV equipment. Lightning protection comprises earthed rods mounted on masts/poles and surge arrestors on equipment.

Condition, performance, and risks

One of the safety risks in our zone substations are step and touch potential hazards during earth faults. A layer of crushed rock is installed in the outdoor switchyards of all our zone substations to reduce step and touch potential hazards by providing an insulating layer.

We use consultants to carry out current injection testing of most of our zone substations to evaluate the step and touch voltage hazards. As part of the testing, the crushed rock layer is also inspected. Areas where we deviate from the industry guidelines for earthing, are fixed by installing additional deep driven earth rods and extending earth mats. Due to the types of soil we have across our network, earth resistance values change dramatically and in cases it is impossible to meet industry guidelines. We evaluate the risk based on likelihood and consequence when deciding to what extent we attempt to reduce system earth resistance values to align with the industry guidelines.

Another key risk we manage is access and site security. Fencing around zone substations is very important to keep the site secure and prevent unwanted access. The condition of our fencing is very good and security systems are generally good to excellent. We have a programme to replace old security and fire protection systems that are no longer maintainable so that we can bring all sites up to excellent status over the planning period.

Design and construct

We follow standard designs for HV overhead bus systems and fencing.

For the earthing designs, we use an external specialist consultant. After the installation of an earthing system, we get the consultant to test the effectiveness of the earthing system. They carry out current injection testing to confirm that step and touch voltages are within the desired limits and that the earthing system is as per design. Additional work may be carried out if the testing indicates that this is required.

Operate and maintain

Our general zone substation maintenance tasks are summarised in Table 38. The detailed regime is set out in our maintenance standard.

Maintenance and inspection task	Frequency
Site vegetation work – mowing, weeding. Check waterways.	Monthly
General visual inspection of outdoor structures, busbars, site infrastructure, security equipment and fencing.	Monthly
Detailed visual inspection of site infrastructure. Thermal scan of busbar connections.	Annually
Detailed inspection of busbar connections, insulators, and bushings. Detailed condition assessment of outdoor structures.	Four yearly.
Review of step and touch voltage hazards carrying out current injection testing. Crushed rock inspection.	10-yearly.

Table 38: Other assets maintenance and inspection tasks.

Renew or dispose

Faulty components and assets are replaced/repaired as required.

Mobile equipment

Our mobile asset fleet consist of a mobile substation and a few standby diesel generators. The mobile substation functions as a zone substation and we have the ability to transform voltages from 33kV to 11kV, or use it as a step-up zone substation. The mobile substation comprises of a single 33kV circuit breaker and two 11kV feeder CBs, a 9MVA power transformer and all associated protection systems. Our mobile diesel generators are detailed in Table 39.

Number	Size	Connection voltage
2	810kVA	400V or 11kV
1	275kVA	400V
1	150kVA	400V
6	6.5kVA	230V

Table 39: Mobile generation fleet details.

Operate and maintain

We utilise the mobile substation mainly for planned zone substation maintenance. It allows us to remove a complete zone substation from service. This includes the zone substation power transformer, all switchgear, and associated protections systems, as well as the DC supply system.

The mobile substation is put into service, while the permanent substation is maintained without any power interruption to our customers. Planned maintenance and asset replacement work can then progress without a power supply interruption.

The mobile substation can also be used for unplanned outages related to zone substation primary and/or secondary system failures.

Distribution transformers

This section describes our distribution transformers portfolio. The portfolio includes three fleets:

- Pole mounted distribution transformers
- Ground mounted distribution transformers
- Other distribution transformers, which includes voltage regulator, capacitor, conversion and SWER transformers

This section provides an overview of these assets, including their population, age, and condition. It explains our renewals approach and provides expenditure forecasts for the planning period.

"Investment in distribution substations and transformers is forecast at $32M over the planning period. This portfolio accounts for 23% of the renewals expenditure over the planning period."

Portfolio objectives

Distribution transformers convert electrical energy of higher voltage to a lower voltage used by consumer appliances. Transformer effective performance is essential for maintaining a safe and reliable network.

Transformers come in a variety of sizes, single or three-phase, and ground or pole-mounted. All our transformers are oil-filled, which carries environmental and fire risks. Managing our distribution transformers assets, including correctly disposing of these assets when they are retired, is critical to safeguarding the public and mitigating oil spills.

To guide our asset management activities, we have defined a set of objectives for our distribution transformers, as detailed in Table 40.

Asset management objective	Portfolio objective
Safety & environment	Seismic evaluation of all two-pole substations and relocation at ground level where appropriate. Action all oil leaks as soon as possible and treat any contaminated soil. Appropriate and proficient application of herbicides to safeguard human health and preserve the environment.
Customer service levels	Replace pole-mounted transformers within 24 hours of failure. Continue to monitor ground-mounted transformers through maintenance inspections and condition assessments for timely replacement
Cost	Ensure all installations are fit for purpose and most cost-effective solutions are designed and constructed.
Community	Consider the location of any new distribution substations and impact on residents or businesses. Consult with community on the placement of new transformers.
Asset management capability	Implement inspection and maintenance programs in our EAM system. Record condition information is EAM system.

Table 40: Distribution transformer portfolio objectives.

Fleet overview

Distribution substations and transformers step down voltage for local distribution. Pole-mounted transformers are generally smaller and supply fewer customers than ground-mounted transformers. These are usually located in rural or suburban areas where the distribution network is overhead. In suburban areas where the supply is overhead, the larger pole-mounted transformers are referred to as two-pole substations.

The majority of our ground-mounted distribution transformers are in suburban and CBD areas that are supplied via underground cable networks. These units are larger, more expensive and supply more customer connection points as well as more critical loads. An example of this is the more than 60 units (500kVA to 1500kVA) on the Fonterra Clandeboye factory site.

Voltage regulators improve the voltage levels on long distribution lines, and as such, they do not strictly provide a power supply to customers, but rather ensures the supply is of acceptable quality. Most of our voltage regulators are pole mounted.

Population and age statistics

Distribution substations and transformers step down the voltage for local distribution. We have six,115 oil-filled distribution transformers in service, and the age profile resembles that of the 11kV overhead lines and cables. The most significant investments in distribution substations and transformers were made in the late 1950s, early 1970s, 2000s, and 2010s.

Rating	Number	% of total
≤ 15kVA	2,672	43.7%
>15 and ≤ 30kVA	1,156	18.9%
>30 and ≤ 100kVA	1,076	17.6%
>100 and ≤ 250kVA	617	10.1%
>250 and ≤ 500kVA	431	7.0%
>500 and ≤ 1500kVA	163	2.7%
TOTAL	**6,115**	**100%**

Table 41: Distribution transformer population by rating.

The in-service distribution transformers by kVA rating and percentage of the overall population are given in Table 41. The age profiles for pole mounted and ground mounted distribution transformers are given in Figure 34 and Figure 35, respectively.

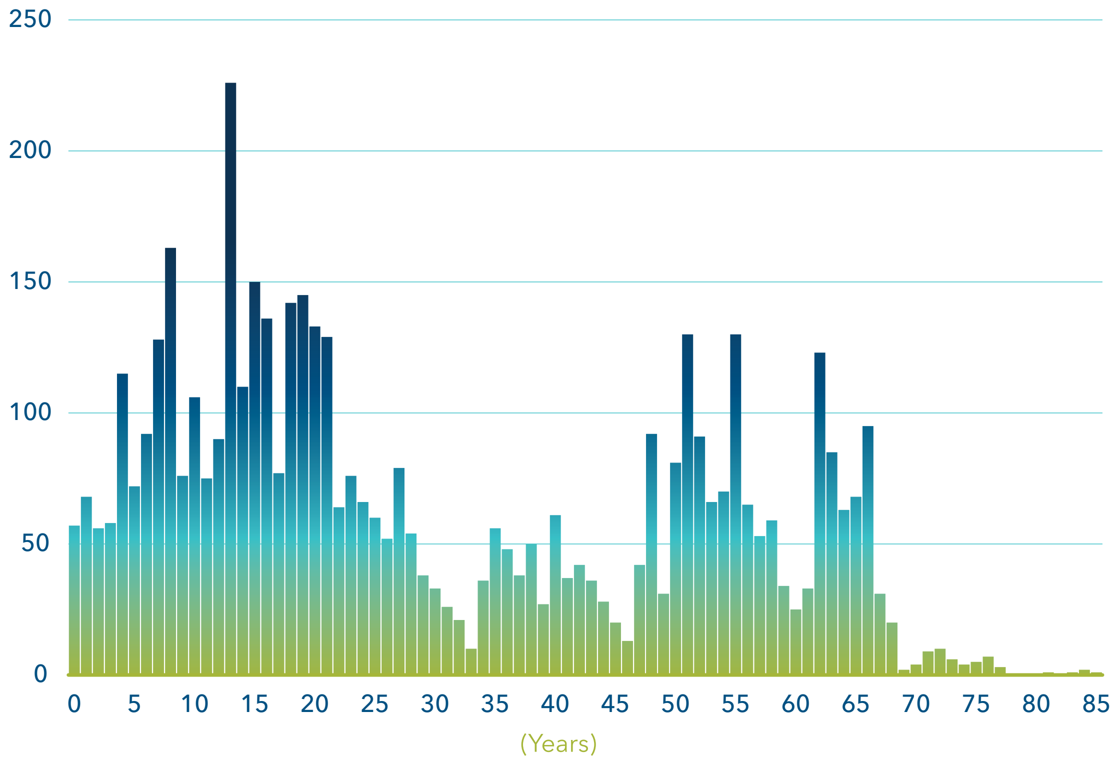


Figure 34: Pole mounted distribution transformer age profile in years.

The standard life of transformers are 45 years. While most of our distribution transformers are less than 30 years old, some are older than 60 years.

We have 34 voltage regulator sites installed on our network. They comprise mainly of two-can installations with some three-can installations. The majority are less than 15 years old and reflects the increase in rural load on our network because of dairy conversions and on farm irrigation that started in the early 2000s. The age profile depicted in Figure 36 counts individual phases or cans. We have changed the way we record these on our asset register where each individual can constitute an individual asset.

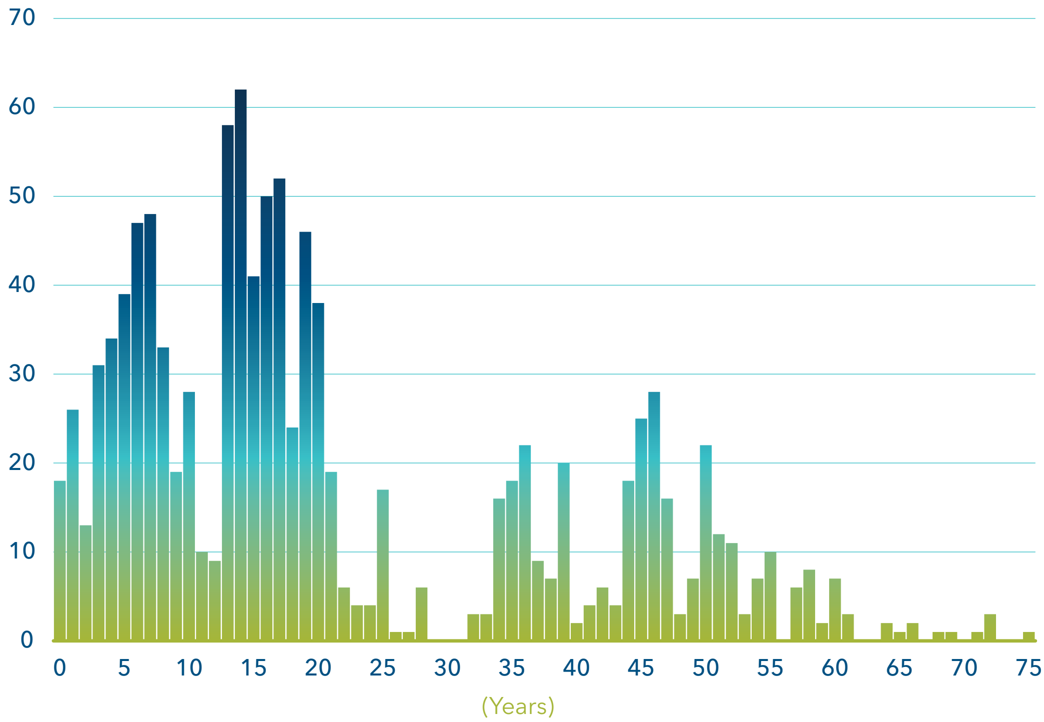


Figure 35: Ground-mounted distribution transformer age profile in years.

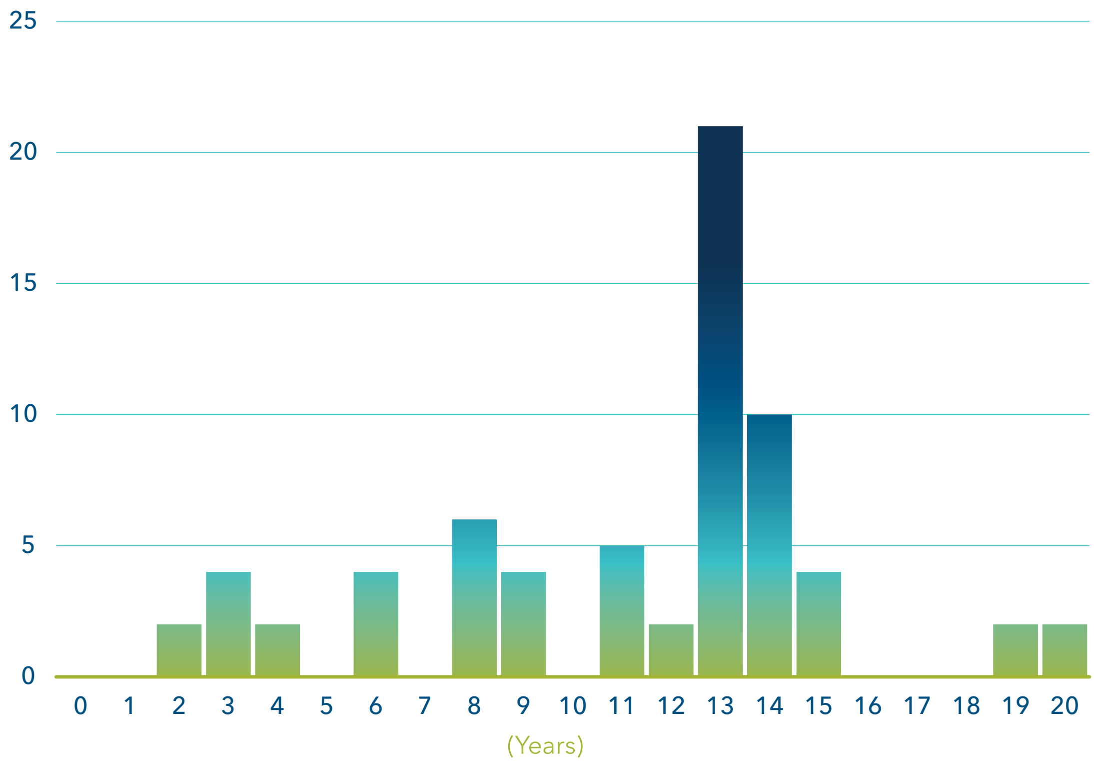


Figure 36: Voltage regulator age profile in years.

Condition, performance, and risks

Overall, our distribution transformer fleet is in a good condition. Because of the standards to which they are designed and manufactured, they are capable of operating beyond their nameplate ratings. The age-based asset health profile for our distribution transformers is shown in Figure 37.

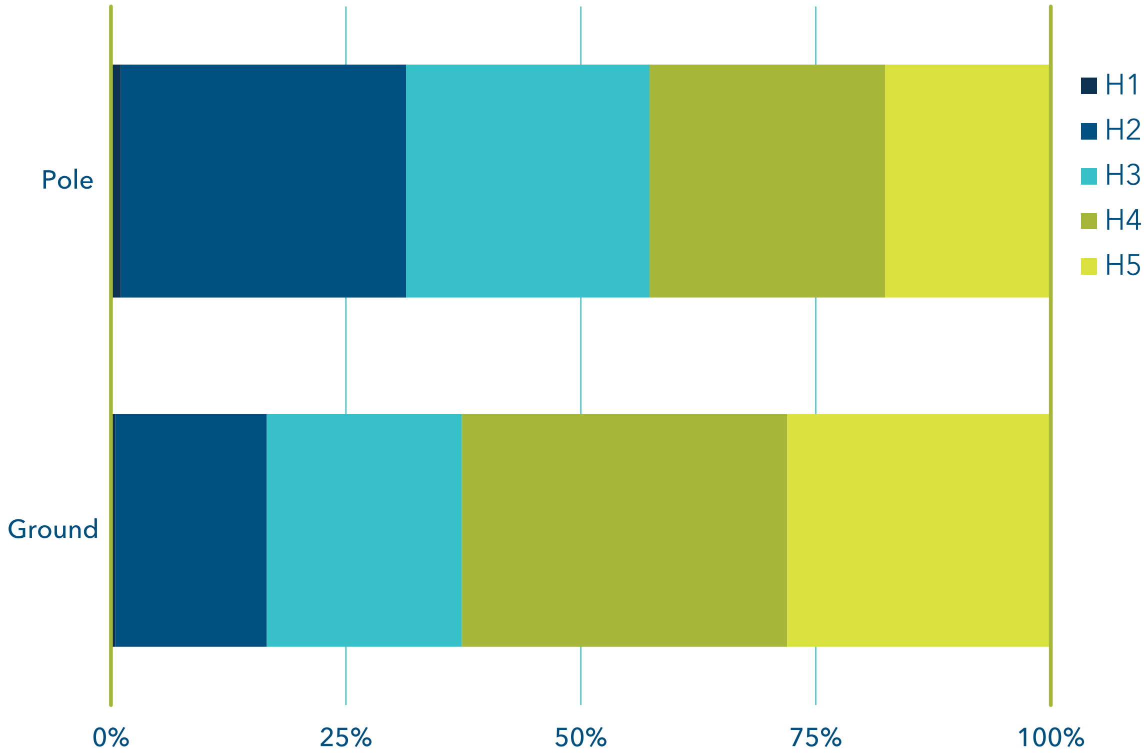


Figure 37: Distribution transformer asset health as of 2022/23.

The biggest risk to our fleet is lightning and vehicles coming into contact with our poles.

The age-based asset health profile for voltage regulators is shown in Figure 38. From the graph our regulator fleet is young compared to the ODV expected end of life of 55 years.[2]

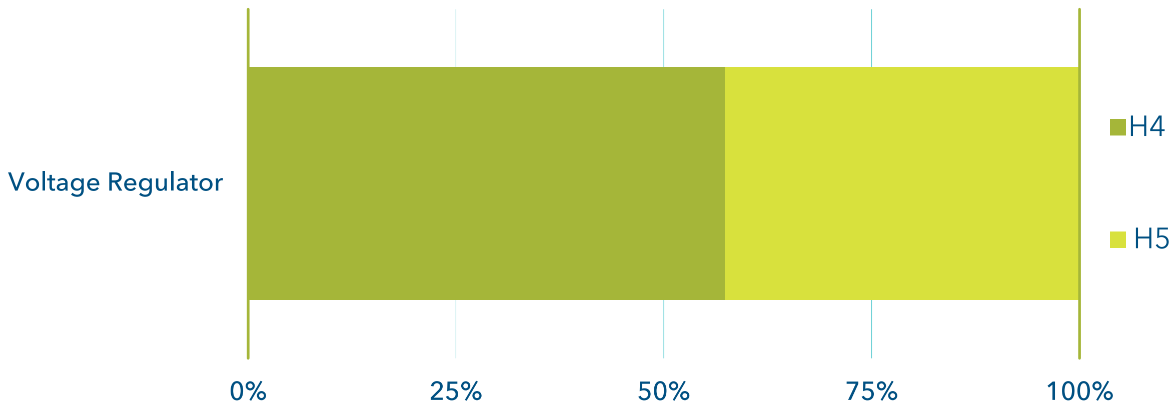


Figure 38: Voltage regulator asset health as of 2022/23.

[2] In accordance with the EEA Asset Health Indicator Guide.

Design and construct

Distribution transformers are designed and constructed to international standards. Our distribution transformer suppliers design and test to AS/NZS 60076 and AS 2374 respectively. They are robust pieces of equipment that seldom fail. When sizing transformers for a specific application, we do allow for some measure of future growth. We also need to cater for the future EV, PV, and infill related growth when we specify the capacity of our transformers. This eliminates the need to upgrade transformers regularly because of generic load growth. The incremental premium payable for the increased capacity is well below any upgrade or replacement costs.

We have standard construction design standards for both pole-mounted and ground-mounted transformer installations. This allows us to efficiently construct and maintain installations. For pad mount transformers, we utilise a design standard prepared by registered chartered engineers to ensure earthquake resilience.

Operate and maintain

Condition assessment for pole-mounted units is done as part of our overhead line inspections regime. We have scheduled inspection and maintenance programs for ground-mounted units, which tend to be larger and supply substantially more customers.

Distribution transformers do not require intrusive maintenance. Pole mounted transformers are often run to failure as these are easily replaced at a much lower cost than to implement a maintenance regime. Large ground-mounted transformers are more thoroughly checked for oil leaks, rust, and bushing damage as part of the maintenance program.

Our voltage regulators are maintained on a four-year programme because they have electronic controllers that require regular testing. In addition, there are internal contacts that can wear depending on the number of operations, and they are also inspected and repaired.

Renew or dispose

Pole-mounted transformers which make up approximately 60% of our fleet, are replaced on a reactive basis. This can be due to failures related to lightning, third party damage or because of condition assessment during overhead line inspections.

The larger ground-mounted, and two pole substation transformers, are proactively replaced based on age and condition. All scrapped transformer oil is drained and recycled through certified processors.

Pole-mounted distribution transformers are replaced as part of the overhead line and pole structure renewal and renewal programme when their condition is classified as AHI level 1. Most pole-mounted transformer replacements are as a result of lightning. This varies year-on-year, but on average we replace approximately 10 units of various sizes.

Ground-mounted distribution transformers are replaced based on condition or as part of our underground substation replacement program. We aim to replace all 30 remaining underground substations with above ground equivalents at three to four per annum.

In 2022, the electrical equipment supply market experienced significant volatility, with an average price increase of 35%. As a result, projecting distribution transformer expenditure for Asset Renewal and Replacement (ARR) has proven difficult for the planning period. There is thus currently a disconnect between our ARR needs and our budget. Our distribution transformer replacements are currently risk based, and not based on the age of the assets.

Table 42 summarises the projected expenditure for distribution transformer and underground substation replacements for the planning period. This expenditure forecast includes the replacement of RMUs and associated cable work associated with the underground substations.

Rating	Number	Annual Replacement	Estimate ($'000)
≤ 15kVA	2,672	59	590
>15 and ≤ 30kVA	1,156	25	400
>30 and ≤ 100kVA	1,076	24	560
>100 and ≤ 250kVA	617	14	700
>250 and ≤ 500kVA	431	10	1,000
>500 and ≤ 1500kVA	163	3	600
TOTAL	**6,115**	**135**	**3,850**

Table 42: Distribution transformer replacement/renewal program.

Distribution switch gear

This section describes our distribution switchgear portfolio and summarises our associated fleet management plan. An overview of these assets, including their population, age, and condition, is also given. The portfolio includes the following fleets:

- Ground mounted switchgear which consists mainly of RMUs, also includes switches, fuse switches, and links. This type of switchgear is mainly associated with our underground cable networks. Our RMU fleet consists of oil and SF_6 insulated units.
- Pole mounted switches includes drop out fuses, disconnectors (ABS) and links. The vast majority are found on our 11kV overhead network. LV switches are not included in the data.
- CBs, reclosers and sectionalisers.

Portfolio objectives

The portfolio objectives for our distribution switchgear fleet are summarised in Table 43.

Asset management objective	Portfolio objective
Safety & environment	No injuries due to failure or operation of switchgear. No significant SF_6 leaks.
Customer service levels	Continue programme to automate reclosers and voltage regulators. Investigate the use of low-cost automated devices as tie switches.
Cost	Cost-effective expenditure on this asset fleet. Ensure fit for purpose designs based on risk reduction.
Community	Minimise interruptions due to planned and unplanned outages. Inform all affected customers of planned outages promptly.
Asset management capability	Develop maintenance programs in EAM. Capture condition data in EAM to inform maintenance and investment expenditure.

Table 43: Distribution switchgear portfolio objectives.

Population and age statistics

Ring main units

Figure 39 shows our population and age profile for our RMU types on our network. We have a total of 462 RMUs on our network, 220 (48%) oil insulated and 242 (52%) are gas insulated. Around 14% (all oil) are at or just beyond the ODV life of 40 years.

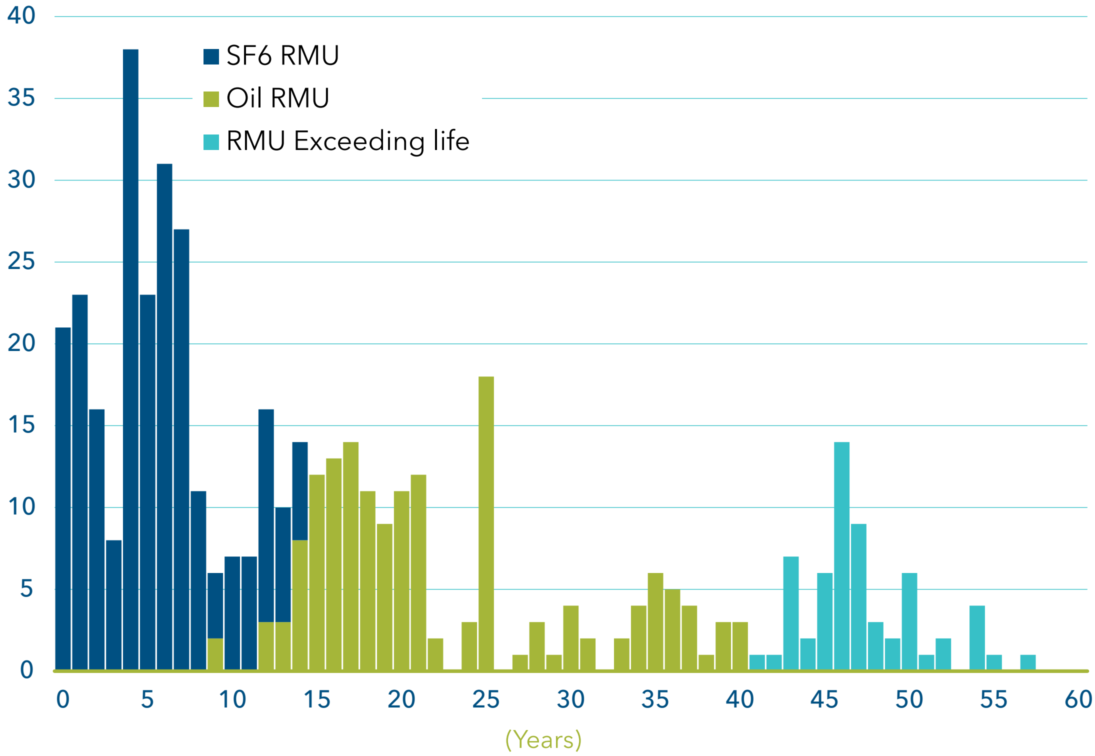


Figure 39: RMU age profile in years.

As shown in Figure 39 our SF_6 insulated RMUs are relatively new, with the oldest 14 years old. We have standardised three types of RMUs for new and replacement projects, all of which are gas (SF_6) insulated. The standard life of RMUs is 40 years.

Pole mounted fuses and switches

A significant proportion of pole-mounted fuses and switches are less than 20 years old, while some date from nearly 60 years ago. They are simple pieces of equipment and maintenance revolves typically around the lubrication of moving parts. Since these switches are maintained as part of the overhead line pole maintenance and replacement program, their condition is better than the age profile would suggest if age alone were taken as a metric of condition.

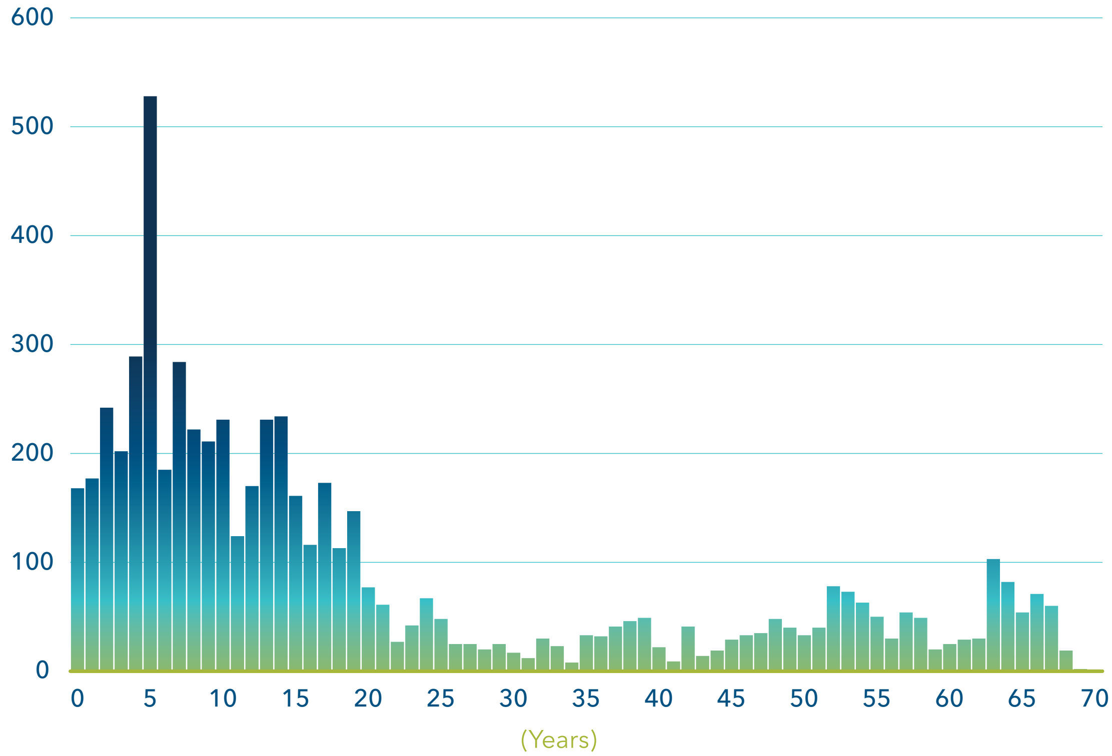


Figure 40: Pole fuse age profile in years.

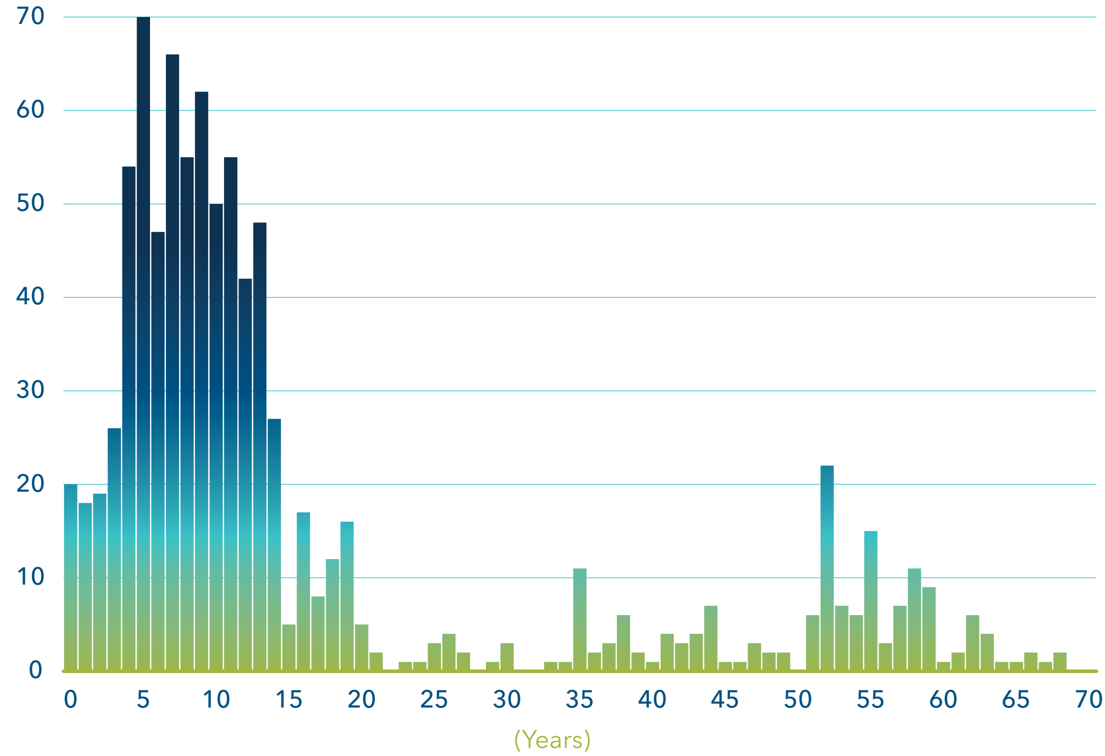


Figure 41: Pole switch age profile in years.

Since the majority of pole-mounted fuses are pole-mounted transformer fuses, a single set supplies a fairly low number of ICPs and in many instances a single ICP. Based on the small number of ICPs supplied, these devices are of a lower criticality level compared to a RMU fuse which can typically supply more than a hundred ICPs.

Circuit breakers, reclosers and sectionalisers

We have several makes and models of 11kV pole mounted reclosers in service on our 11kV distribution network. The types and quantities are summarised in Table 45. Reclosers and sectionalisers are used to protect and isolate the healthy network from faulty parts. By appropriately locating them, outages are managed, and overall network reliability is improved.

Reclosers are pole-mounted switches that can break fault currents. The recloser isolates a fault downstream of the recloser location and preserves the quality of supply for all upstream customers. The reclosers can connect to control units that allow them to re-energise a circuit following an interruption. The control unit strives to restore the supply with minimal delay in the event of a recoverable fault, such as a bird or strong winds causing a line clash. The recloser controller can be maintained and replaced separately from the recloser.

Table 44 summarises the types and quantities of the different reclosers that we use on our network. The age profile of the reclosers are shown in Figure 42, while Figure 43 shows the age profile of the recloser controllers.

Type	Number
Vacuum interrupter & oil insulation	13
Vacuum interrupter & SF_6 insulation	2
Vacuum interrupter & epoxy resin insulation	17
Vacuum interrupter & solid polymer insulation	37

Table 44: Recloser types and quantities.

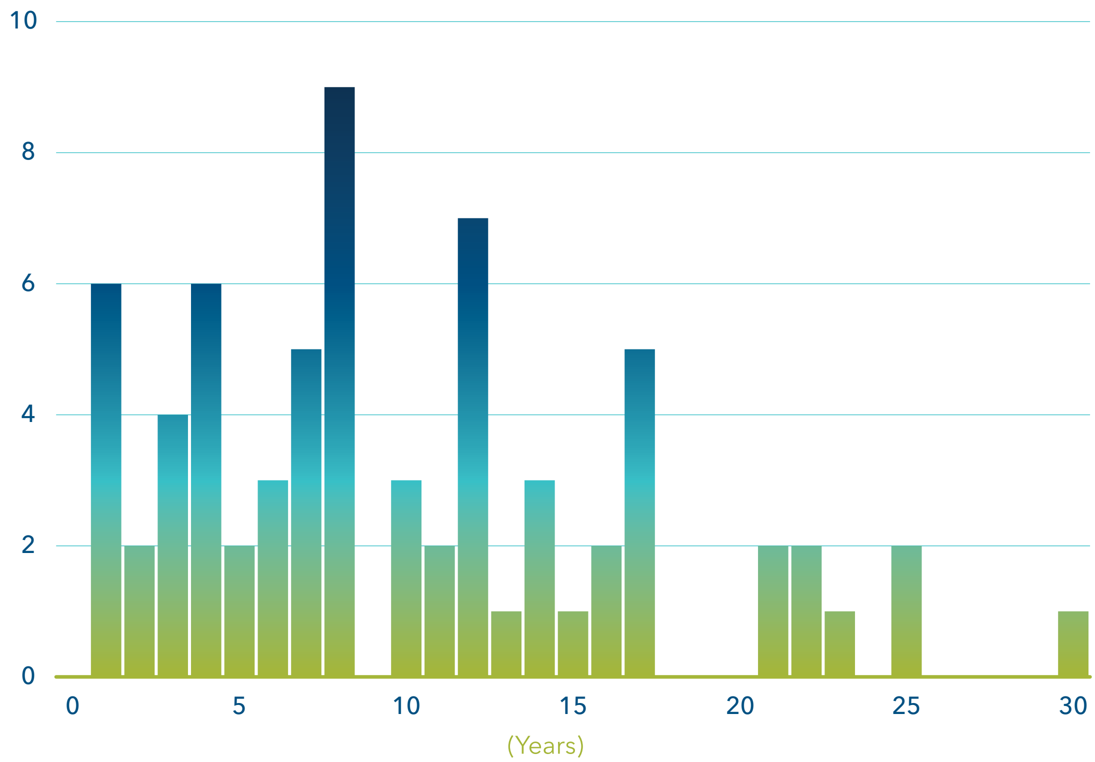


Figure 42: Recloser age profile in years.

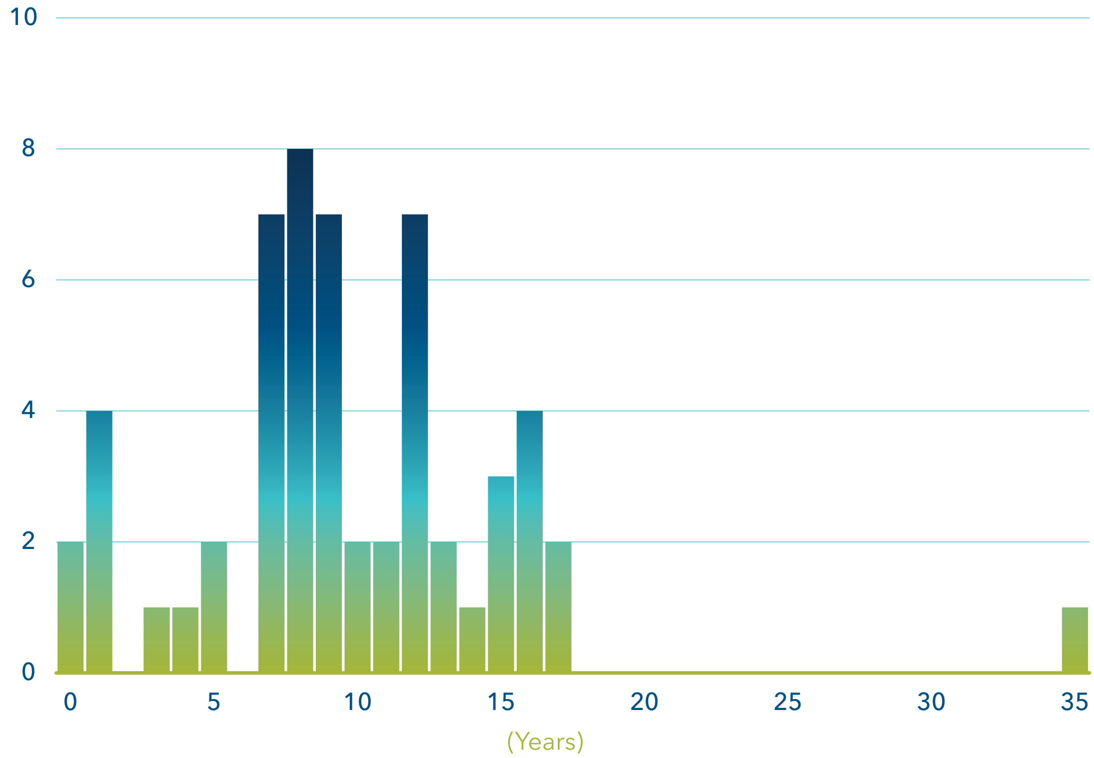


Figure 43: Recloser controller age profile in years.

Condition, performance, and risks

Ground mounted switches

Even though just less than a quarter of our oil RMUs are close to their ODV end of life, their condition is fair to good. These older units were designed to international standards that were more robust with respect to tolerances than modern equivalents. Their condition, like most mechanical devices, is reflected in how well they were maintained, and how hard they were operated. It is fair to say our RMUs have not worked very hard over the years, and this is reflected in their condition.

Our RMUs are performing well for the purpose they were designed. With the increased focus on the reliability of supply, the only lack in performance is one of automation. Modern gear is also designed and built with more focus on maintainability and specifically less maintenance over the life of the asset. We have now installed a small number of modern RMUs with remote control functionality and will continue this practice as part of our renewal and replacement programs. The aged based asset health profile for our RMUs are shown in Figure 44.

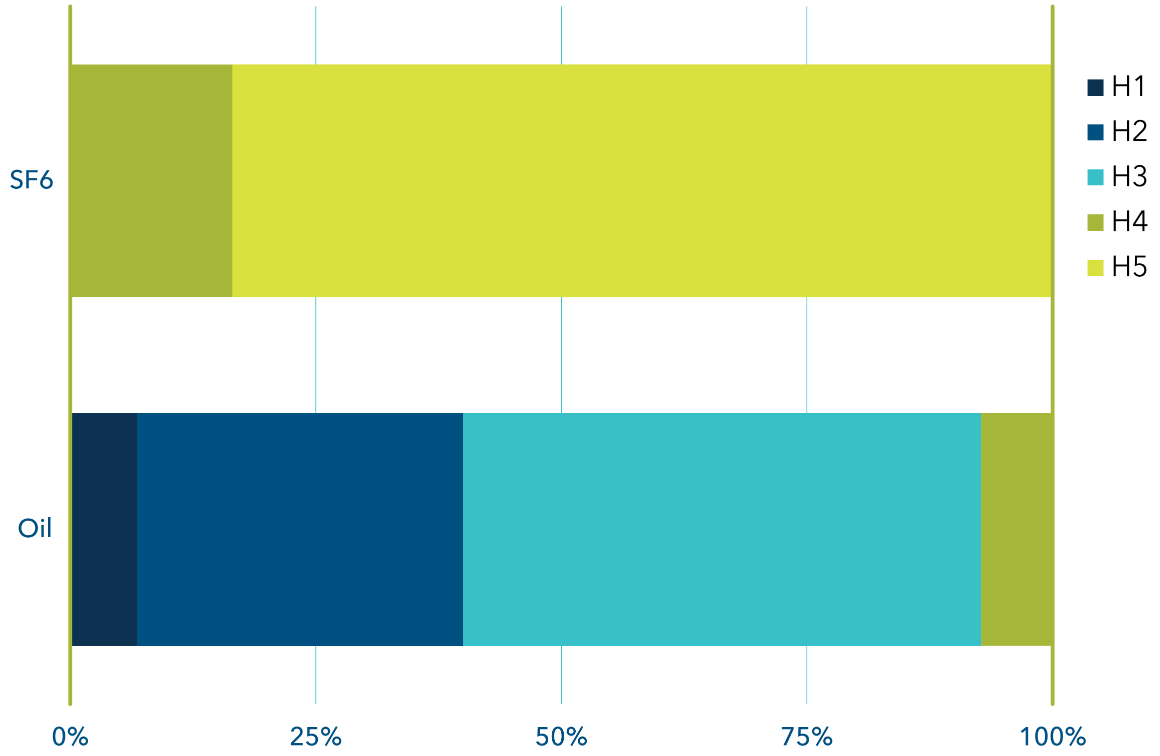


Figure 44: RMU asset health as of 2022/23.

The biggest risk related to this type of switchgear is one of fire with oil-filled equipment. Depending on the type of failure, there is an increased risk that it could result in a fire. Both old and modern gear, due to the nature of their application and function, poses a risk of arc flash. Modern equipment designs account for this, and we specify arc-rated and arc vented equipment where possible.

There is also an inherent environmental risk associated with equipment that contains SF_6 gas for insulation. We mitigate this risk through our SF_6 register and the use of specialised and approved contractors.

Pole mounted fuses and switches

Overall, our pole mounted switches are in good condition, and the asset health profile is shown in Figure 45. The majority of our older assets are transformer fuses.

Older types of 11kV fuse drop-out units can fail under operation. We are replacing the older drop-out fuses, including the old glass tube type fuses, with modern drop-out expulsion fuse units during maintenance.

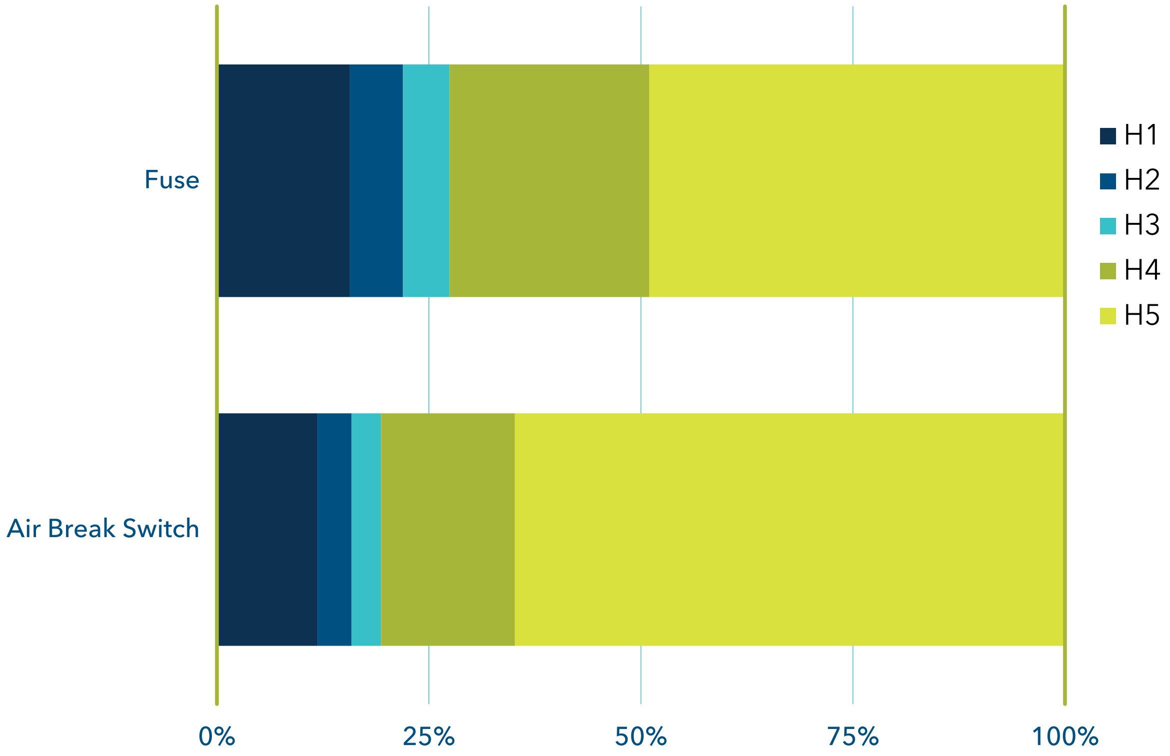


Figure 45: Pole mounted fuse and switch asset health as of 2022/23.

Circuit breakers, reclosers and sectionalisers

The aged based asset health profile for reclosers are shown in Figure 52. The oldest 11kV recloser model in service, dating between 1980 and 2003, has VCBs with mechanism and connections insulated in oil. The original controllers of these units were replaced between 2010 and 2015 and are in good condition. We estimate that these units have at least another one-to two years of life before they may need to be replaced. They will be monitored for condition during their annual battery and earth tests, and their five-year full maintenance cycle.

The next oldest 11kV reclosers are two SF_6 units installed in 2005. These units should have another 20 years of life and will be monitored for condition during annual and five-year maintenance cycles.

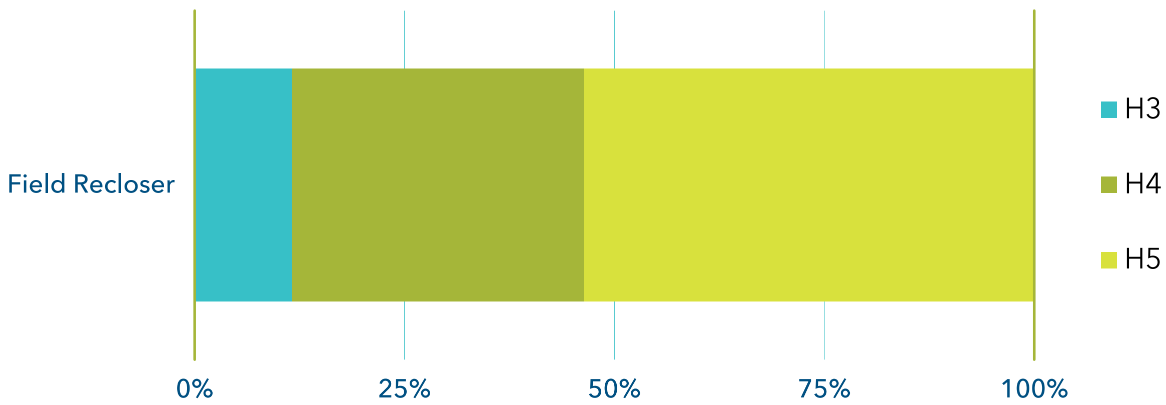


Figure 46: Recloser asset health as of 2022/23.

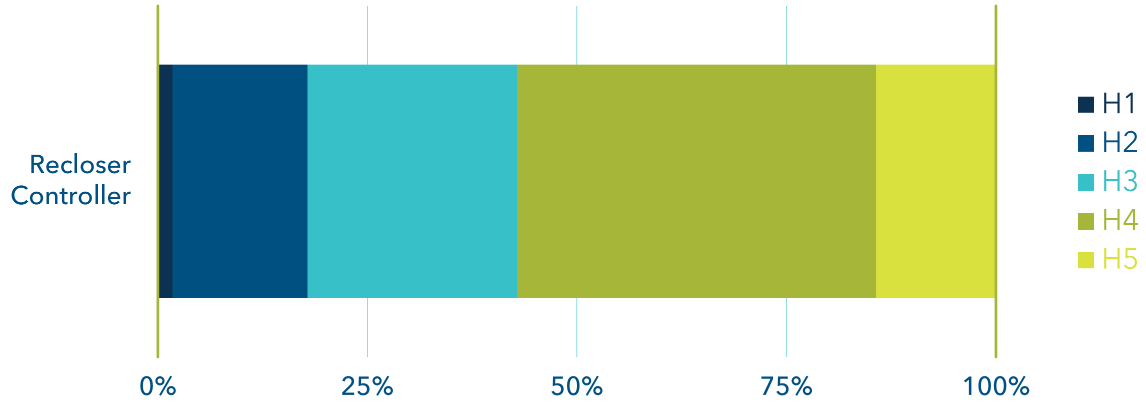


Figure 47: Recloser controller asset health as of 2022/23.

The third oldest units were installed between 2005 and 2013. There are 17 of these units in service. These have VCB with solid insulation. The first batch suffered from lack of immunity from noise on the 11kV network due to insufficient filtering on their current sensor circuits. This was eventually corrected by the manufacturer.

Another drawback suffered by this make of recloser was that the current sensors and associated protection circuitry appeared to be unable to distinguish low primary load current (<10 A) imbalance from earth faults. Consequently, some of these units had to be reassigned to locations with a higher minimum load current.

Another problem arose, necessitating a modification to the power supply earthing, and all the units were updated. Yet another drawback of these units is that the warranty on their control units is 10 years and spares are no longer available for these obsolete control units. Although a modified backward compatible controller can be procured, a controller from an alternative, more reliable supplier cannot be used. We plan to replace these reclosers units before 2030.

The most recent 11kV recloser model in service was introduced in 2013 and is presently our preferred model. Currently there are 14 of these units in service. The condition of these reclosers is generally considered excellent. We expect that these recloser controllers should not need replacing before 2025, and the CBs themselves not before 2035. As for the other recloser models, they will be monitored for condition during annual and five-year maintenance cycles.

Design and construct

We have standardised our designs around two RMU types based on application and ratings. Our designs also require that three core cables be trifurcated in the ground and that single-core cables only be terminated inside the RMU. This eliminates the risk of trifurcation failures also damaging the RMU. The higher current rating RMU type is installed with a locked fibreglass protective cover over it. This also prevents public access to the cables that are terminated inside the RMU.

Air-break switches, as part of the pole-mounted switch family, are mostly designed and constructed on the network so that they can be bypassed if maintenance is required. This ensures that maintenance activities can be undertaken without any power outages.

Our design philosophy for 11kV pole mounted reclosers is that they must be able to be bypassed by an ABS or disconnector to allow supply to be maintained during maintenance of the reclosers and in the event of a failure of a recloser when in service. This is usually achieved by the use of a bypass ABS above, and two sets of isolating links on either side of, the recloser. The additional cost of this equipment is considered acceptable compared with the risk of prolonged customer outages and SAIDI penalties when the recloser fails.

We have also embarked on a programme of remote control and indication of the reclosers so that they may be operated remotely via our existing zone substation SCADA system. This is achieved through the use of radio communication with each recloser site.

Operate and maintain

Ground mounted switches

Maintenance tasks include an annual visual inspection and a scheduled four-to-five-year fixed maintenance programme that aims to maintain every switch. This service also includes an oil test where applicable. Even though our maintenance programme continues to be difficult for a variety of reasons, we are nevertheless able to carry out our programme to reach these ground mounted units and maintain or replace them depending on their condition. Executing our maintenance programme remains constrained by:

- Inability to arrange access to the equipment through outages due to the original network design 20 to 30 years ago
- Having to comply with third-party schedules such as units on industrial processing sites where production is affected

However, these devices are normally operated by hand, with more modern versions having the capability to be remotely controlled. All enclosures are locked and always secured.

Pole mounted fuses and switches

This asset class is maintained as part of the overhead line inspection and refurbishment program. They are simple pieces of equipment and maintenance normally revolves around the lubrication of moving parts. It is often the case that these devices are not operated for many years.

To avoid ferro-resonance where transformers are connected with a cable circuit, the cable connection is through a disconnector (three-phase disconnect), surge arresters, and a three-phase ganged drop-out unit. With ganged drop-out units becoming difficult to source, we have introduced the use of transformers with internal HV fuses. Switching will still be carried out via the disconnector.

Circuit breakers, reclosers and sectionalisers

Reclosers and sectionalisers are maintained on a four-yearly basis in addition to an annual visual inspection regime. The maintenance requires the equipment to be taken out of service. This is done without the need for an outage because of our standardised installation design.

Reclosers are, in addition to a switchable device, also a protective device to isolate faults from the rest of the network. Because they are distributed all over our network, we have embarked on a programme to install remote control and indication functionality. This allows us to operate them from our Control Centre which reduces outage times and improves reliability. To date, we have upgraded 46 (or approximately 73%) of our reclosers.

Renew or dispose

Our ground-mounted switchgear, and specifically our RMUs, are replaced mainly based on condition. However, with the increased focus on reliability and health and safety, we have also embarked on a project to renew our underground substations, all of which contain at least one RMU. We also budget to replace older units depending on the outcome of our maintenance and inspection program. We need to replace 12 RMUs annually at an expected cost of $1.8M.

Pole-mounted switches are replaced as part of our overhead line inspection and maintenance program. As a result, most units are replaced during these programs if they are deemed not in a condition to last another 10 years. We also budget to replace units that fail during operation in addition to replacements under the overhead line replacement and renewal program.

The condition, including operating performance, is the primary criteria for replacement decisions of pole-mounted reclosers. Age will also be considered, particularly with concerns of the electronic components such as the controller and automation equipment. After reaching a certain age, usually considered to be 10 years, electronic equipment can fail unexpectedly due to the aging of components such as capacitors. Batteries are also replaced based upon age, usually after five years from the date of manufacture. We will be replacing three reclosers on our network within the planning period, based on the AHI score of the asset.

All RMUs in our underground substations will be replaced as part of the underground substation replacement program. The budgets for these replacements are combined with the distribution transformer replacement budget forecast as detailed in Table 42.

SCADA and communication systems

The SCADA system provides monitoring, remote control, and the acquisition of data of our network. The SCADA system consists of a master station, RTUs located at substations and controllable devices, and a communications system that connects the master station to the RTUs.

At present, the technology is diverse as it was installed over the years with different standards and requirements. We have undertaken considerable work to improve standardisation, and this will continue in this planning period.

Master stations

A master station is essentially a central computer server that manages the SCADA system. We run our primary master station in our Washdyke office site with a backup on hot standby in our North Street Zone Substation.

We are continually developing and adding new modules to our SCADA system to meet the network's needs for the foreseeable future.

Remote Terminal Units

RTUs are electronic devices that interface network equipment with the master station. They transmit telemetry data to the master station and relay communications from the master station to control connected devices.

We have a range of different RTUs across our network using different protocols. We are standardising toward the Distributed Network Protocol (DNP3).

Communications

The communications network supports our SCADA system as well as our protection, metering, and telemetry systems. The communications network consists of different data systems and physical infrastructure, including fibre optic, radio (UHF, VHF, and microwave) and ethernet IP based circuits. The scope of the communications network also includes the infrastructure that houses communication systems, including masts, buildings, cabinets, and antennae. Some infrastructure services are leased from service providers or shared with third parties.

While some analogue technology also remains in use, we are progressively moving to digital systems to provide a communications network that better meets our future needs.

Voice radio

Voice communications network is a vital infrastructure ensuring that network controllers can communicate with field operators to carry out daily network operations. Our voice communication system consists of VHF, mobile, portable, and fixed radio units with hilltop repeater sites that are connected via UHF trunk radio links to our Control Centre.

The current in-service system is analogue, and we have developed a radio strategy to upgrade to digital systems.

Portfolio objectives

The SCADA asset portfolio objectives are listed in the Table 45.

Asset management objective	Portfolio objective
Safety & environment	The SCADA system enables remote operation of network assets in lieu of onsite operation.
Service levels	The SCADA system allows reliable and speedy control and monitoring of the electricity network at all times.
Cost	Consider the use of more maintenance-free communications equipment to reduce the cost of maintenance.
Community	Provide timely and helpful outage information through the SCADA outage portal.
Asset management capability.	Migrate the existing analogue communications network infrastructure to a digital platform.

Table 45: SCADA systems portfolio objectives.

Population and age statistics

In previous years, we have undertaken several projects to modernise our RTUs to provide acceptable levels of service. In this planning period, we will focus on replacing the three remaining legacy RTUs.

Table 46 summarises our population of RTUs by type. This population excludes telemetered sites with Intelligent Electronic Devices (IEDs) directly connected to the SCADA network, such as those on modern automated reclosers.

Type	RTUs	% of total
Modern	39	93%
Legacy	3	7%
TOTAL	**42**	**100%**

Table 46: RTU population by type on 31 March 2022/23.

At the end of our replacement programme, we will have the SCADA network standardised on the industry standard DNP3 protocol. The open DNP3 standard allows direct connection of some IEDs to the SCADA master without the requirement of an intermediary RTU.

Age information for our communications network is disparate and is typically inferred from related assets or drawings of the installations. We are working to improve our records.

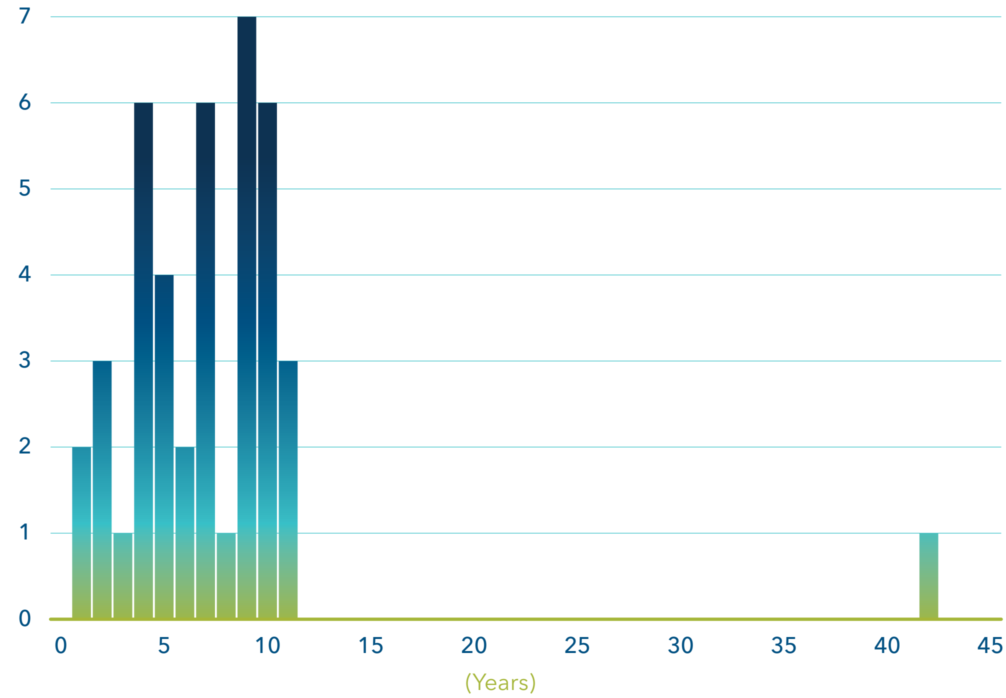


Figure 48: Zone substation SCADA and communications age profile.

Condition, performance, and risks

The small numbers of legacy RTUs on the network are based on proprietary hardware, software, and communications protocols. They cannot communicate with modern numerical relays using standard interfaces. Instead, they rely primarily on hard-wired connections, which are more prone to failure, are difficult to maintain and troubleshoot, and require specialist knowledge to understand how they work. These RTUs rarely fail, but a lack of experienced service personnel and original spares increases risk. The age-based asset health of our RTUs is shown in Figure 49.

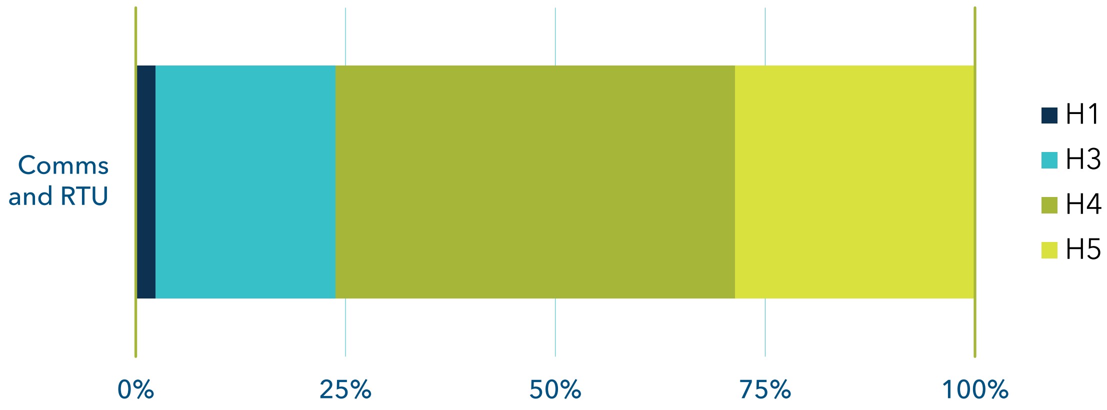


Figure 49: RTU asset health as of 2022/23.

With regards to our SCADA system, the key risk is loss of network visibility and control. It is preferable to operate equipment remotely for a number of reasons, including safety, speed of operation and improved operational visibility. Lack of status information from the field can lead to switching errors such as closing on to a faulted piece of equipment or circuit.

Another significant risk is a cyber-attack, or a third-party gaining control of our SCADA system. As more devices become visible and controllable on the network, the potential safety, reliability, and cost consequences from anattack on the system become increasingly serious. We continually review and improve the security of our SCADA against cyber-attack to ensure the operational safety of the network.

Design and construct

Technology changes are affecting SCADA and communications in several ways. As numerical protection relays and other IEDs become more prevalent and powerful, more data is collected. This requires alternative polling strategies to manage data requirements and increased communications bandwidth.

We will monitor these changes in technology closely to ensure that any benefits to our SCADA system can be promptly identified and implemented as appropriate.

The latest standard RTU types that we are installing provide remote access capability for most of our numerical relays. This allows our technicians and engineers to access relay and download event information remotely, removing the need to download the data at the site from the relay. This could potentially reduce the time required to understand and react to a fault, thus reducing the length of power cuts for customers.

In terms of communications, moving from analogue to digital technology will allow for greater data transfer and manageability. Greater intelligence within the communications system, between IED controlled switches and the master station, will allow for automatic fault restoration.

Communications systems also enable emerging technology in other areas, such as providing mobility solutions to our field workforce. Expected improvements include providing improved access to up-to-date asset information and integration with work packs.

Operate and maintain

SCADA and communications assets are regularly inspected and tested to ensure their ongoing reliability and they remain within specifications.

Asset type	Maintenance and inspection task	Frequency
Communications equipment, including RTUs	General equipment inspections to test asset reliability and condition. Site visual inspection for dedicated communications sites, checking building condition and ancillary services	Three monthly
SCADA master station	Apply patches	As required

Table 47: SCADA and communications maintenance and inspection tasks.

Renew or dispose

SCADA and communications asset renewal are primarily based on functional obsolescence. As detailed earlier, there remains three legacy RTUs on the network, which are based on proprietary hardware and communications protocols. They are unable to communicate through standard interfaces with modern IEDs. There is a lack of knowledgeable personnel to undertake related work and a lack of spares. Therefore, the replacement of these legacy RTUs is a high priority.

Other communications assets, such as radio links and their associated hardware, are also typically replaced due to obsolescence. Modern primary assets and protection relays can collect an increasing amount of data that is useful for managing the network. To support this, legacy communication assets are replaced with modern, more functional assets. The renewal of supporting communications infrastructure, such as masts and buildings, is condition-based.

Our renewal forecasts are based on identifying asset types that require replacement. The renewal forecast is an estimate of the expected annual replacement quantity based on historical renewals.

In this planning period, we expect an increase in SCADA and communications renewals to cater for the replacement of legacy assets as well as expansion of the communications network.

09. Supporting our network

Supporting our network

While much of our AMP is about our physical electricity distribution assets, meeting the future demands on our network and business requires a broader approach. Our non-network assets, systems operations, network support, and other business support functions play a vital role in our strategy and driving the necessary transformation.

This section describes our teams, our supporting systems and our work programmes that help to deliver the management of our physical electricity distribution assets and infrastructure. We describe the forecast investment needed in non-network assets and the key capabilities needed in our support teams to support the deliver our AMP. We also highlight our current and planned innovation practices and projects.

Non-network assets

Our significant non-network assets include:

Digital: Information systems, processes & data

Property: Corporate buildings

Fleet: Vehicles

These assets are all essential to ensure that we can deliver safe, reliable electricity to South Canterbury. They equip our people with the physical and digital tools, premises and other assets they need to deliver the level of service our customers expect.

Our digital tools

Our current suite of technology solutions

We have a range of technology solutions that we use to support the operations of our network and ensure that our asset, financial, and other critical information are securely captured, stored and accessible for risk mitigation and decision-making processes.

As per Section 5, our core Asset Information Systems are as follows:

- TechnologyOne OneEnergy (T1) is our Enterprise Resource Planning (ERP) system for our asset management and finance processes
- Esri's ArcGIS and Schneider ArcFM is our GIS solution with a variety of applications, modules, and extensions for geographic, schematic and connectivity information and geospatial visualisation
- Survalent is our SCADA system, used to monitor and control operations on the network and provide data on network loading
- Adept is our drawing management and drawing version control system
- Microsoft Teams and Microsoft SharePoint Online are our collaboration and online document sharing solutions
- We use on-premises network file shares for document and information management and storing photos and images

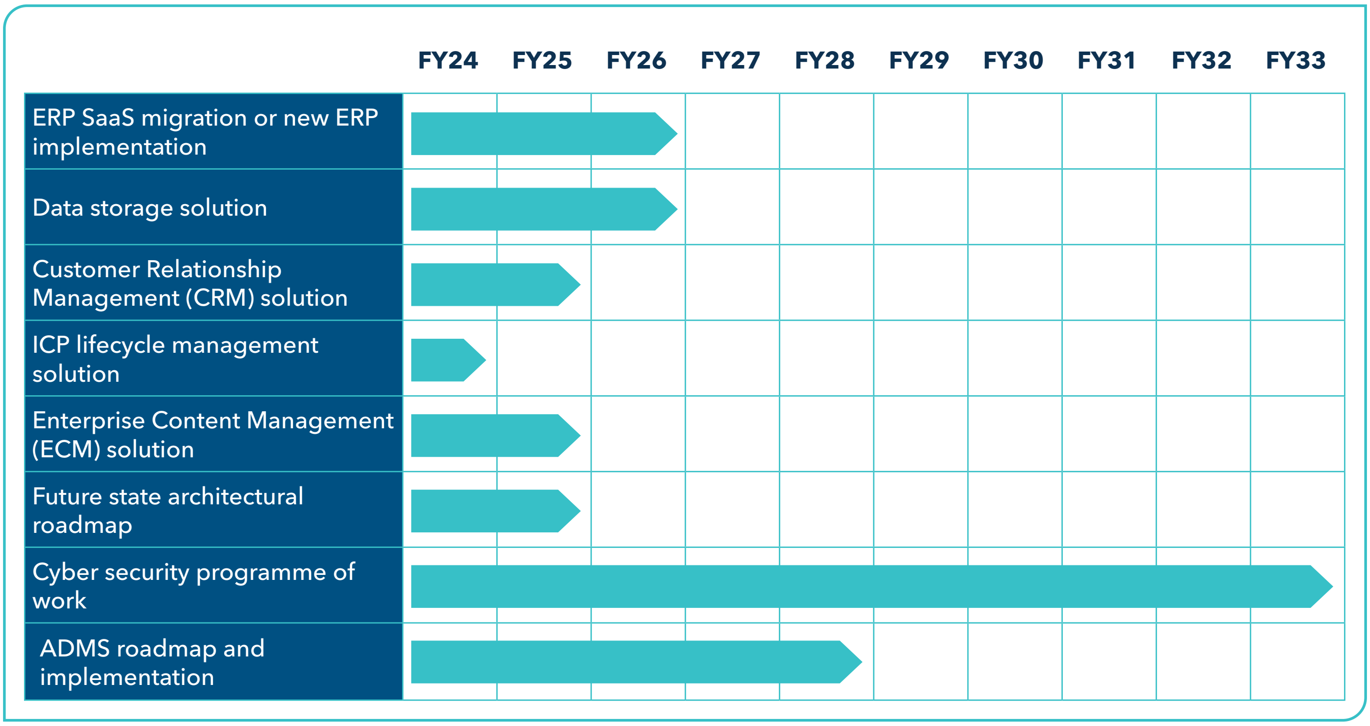
In addition, we use the following enterprise systems, infrastructure, tools, and databases to support our asset management and service delivery:

- We have a significant on-premises infrastructure footprint including SQL and Windows Servers, Azure and Windows Remote Desktop. Backup solutions include Veeam, Azure and Polaris
- We currently use an inhouse database to record our connected ICPs, which is scheduled to be replaced in 2023/24
- Axos is our billing system and is used to interface with the EA Registry
- WhereScape provides our on-premises data warehouse, and we use Tableau and Microsoft PowerBI to visualise data and inform our decision-making
- FME is our data integration layer and is predominantly used to integrate GIS with other systems and data sources
- Microsoft 365 is our enterprise productivity suite
- We have a variety of software-as-a-service (SaaS) products in use across our business support functions including Vault for Health and Safety and KnowBe4 for cyber security training
- The Grid is our intranet site which was launched in 2021 and provides system process and learning documentation to our employees

While we move through this AMP period, some of our existing information systems will reach the end of their lifecycles, as many system providers are planning to discontinue support for on-premise versions of their products. This will necessitate significant investment in either CAPEX or OPEX to upgrade, replace, or migrate these systems to new platforms.

We identified several potential systems and solutions that align with the goals outlined in our Digital Strategy, including greenfield options that provide new functionality or visibility of information. These opportunities are outlined in the planned investment table below. It is important to note that the adoption of these new systems will require an uplift of our employees' digital capability to ensure we are able to make the most of these new tools. Technology is constantly evolving, and we anticipate that this investment cycle will likely need to be repeated during the life of the AMP, as no technology can be expected to remain in use for the next 10 years.

Our planned investment in digital



ERP SaaS migration or new ERP implementation

Our current on-premises ERP version will no longer be supported by T1 by October 2024. We must decide whether the T1 SaaS product is suitable to deliver on our future state requirements within the next year.

In preparation for this deadline, we are undertaking a review of the configuration, reporting, data structures, process, and utilisation across our current T1 application suite.

The review will provide us with important findings to inform our decision, but we also must consider our existing technical debt and the high volume of integrations between T1 and other enterprise systems such as our GIS application suite. These integrations add further complexity to any migration to the T1 SaaS product.

We will likely consider our options as to whether we migrate to T1 SaaS or if we prepare for the implementation of a new ERP with a decision likely by the end of 2023/24.

Data storage solution

This year, we have engaged a data and analytics organisation to develop an effective management dashboard using Microsoft Power BI. We plan to continue working with the same organisation to create a fit-for-purpose data strategy. The data strategy will produce a series of sequenced recommendations for our future state data storage solution that aligns with data standards and governance requirements. This will involve cleaning and capturing structured electronic data.

Customer Relationship Management solution

To support our Customer strategic pillar, we will scope our requirements for a CRM system in the next two years. A CRM will provide visibility of our customer data, engagements and enquiries and support the development of customer-related performance measures, and the reporting new ID requirements proposed by the Commerce Commission.

ICP lifecycle management solution

We will replace our inhouse ICP database with an ICP lifecycle management system in 2023/24 . The system will also manage the synchronisation to and from the Electricity Registry to ensure our data is in line with the Electricity Registry master data.

Enterprise Content Management solution

We are in the process of implementing a modern and secure Enterprise Content Management (ECM) solution. This solution will leverage our existing core systems, providing improved management of our content, enhanced search capabilities, and lifecycle management.

Future-state architectural roadmap

We plan to develop an architectural roadmap to provide us with sequencing and design options for our future state. This roadmap will closely align with our data strategy and associated data architecture and will guide our planned digital investment journey.

As previously discussed, we have a series of decisions to make about our current systems and identified systems or solutions that we do not currently have.

The future-state architectural roadmap will deliver a detailed review of our current state and will inform how and when we implement some of our other key planned digital investments.

Cyber security programme of work

As highlighted in the section outlining our digital tools and strategies, we have an ongoing programme of cyber security work which will continue through this AMP period.

Future technologies

Advanced Distribution Management System roadmap

We are committed to investing in platforms that enhance and improve the core operations of our network. One of our key decisions in this area is when and how we prepare to implement an ADMS.

An ADMS is the decision support environment that provides a shared network model and a common user experience for all roles that are required to monitor, control, and optimise the secure operations of the electricity distribution grid. Currently around half of New Zealand's EDBs have an operational ADMS, and we are one of the EDBs who do not.

ADMS functions can include:

- Distribution state estimation
- Fault location
- Isolation and restoration
- Volt/volt-ampere reactive optimisation
- Outage management
- Conservation through voltage reduction
- Peak demand management
- Impact assessment of DERs

These functions all work to improve outage restoration and daily grid operations and enable the deferral of new investment in network assets. An effective ADMS can also improve customer satisfaction (for example, through accurate prediction of restoration times) and distribution reliability (through optimisation of distribution network configurations).

However, an ADMS is a complex production environment, crossing both IT and OT, and is data-intensive, with three-year implementation programmes commonly observed, irrespective of deployment pattern (on-premises, hybrid, and cloud).

This has resulted in product choices that are not easily reversed and as such we will undertake a comprehensive roadmap process which will clearly lay out the requirements and dependencies that must be considered for us to deliver our future network technologies.

Emerging future network technologies

The advancements in non-network asset management technologies and digital and information management systems offer us opportunities to improve our monitoring and control of assets. These non-network technologies also provide cost-effective and secure methods of engagement with our customers and integration of DERs.

Our objective is to create a network that is more responsive, flexible, integrated, and affordable for all our customers. To achieve this, given the ever-evolving technology landscape, our non-network investment strategy prioritises the utilisation of new and emerging digital technologies or the optimisation of existing solutions, with the aim of delivering the best outcome for our customers. Our plan continually evaluates the optimal solutions to ensure we are adapting to the latest technological developments and delivering the best possible outcome for our customers.

By investing in non-network digital systems, processes, and information management, we aim to manage uncertainty and create a network that is sustainable and resilient for future generations. Our asset management approach is not limited to physical assets and infrastructure, but also encompasses the supporting systems and processes that underpin the management of our assets and future environment.

It is important to our future network to invest in the right technology solutions, which may include any or all of the below.

Outage Management System

An OMS (or OMS functionality integrated within an ADMS) can be used to manage calls and outage restoration efforts, real-time tracking of both planned and unplanned power interruptions and provide information to our customers.

The efficient prediction of outages and outage locations, combined with increased media communications leveraging outage data can lead to improved customer interactions and satisfaction.

An OMS could also facilitate real-time SAIDI and SAIFI dashboard reporting during fault events.

Distributed Energy Resource Management System

Over the past 18 months we have seen a significant increase in requests and applications for embedded generation including medium to large scale connections. A Distributed Energy Resource Management System (DERMS) could help enable decarbonisation within South Canterbury by the efficient deployment of energy resources and storage solutions in real-time. A DERMs could also enable and facilitate a future network that includes DG, energy storage solutions and flexibility services.

Future infrastructure resource modelling

We aim to work towards an advanced network infrastructure model to analyse multiple scenarios and to help us understand how we plan an optimised future state network. These models are typically used to help technically enable desired business outcomes.

The creation of an advanced network infrastructure model would enable us to continually improve our planning and specifications, and operational efficiency. We would be able to stress-test important assets and systems in preparation for a wide range of scenarios, including severe weather events.

Our desired future-state would be the creation of a virtual representation of our network or a digital twin. A digital twin is a technology-enabled proxy that mirrors the state of an asset or process. Digital twin elements include model, data, unique one-to-one association and monitorability.

However, digital twins present a significant technical complication due to the blend of IT and OT needed to develop and maintain them. As such we will ensure that our future infrastructure resource modelling is fit-for-purpose and realistically based on our capabilities as a mid-sized EDB.

LiDAR utilisation

LiDAR is an optical remote-sensing technique for precisely scanning surfaces from a distance with laser light. LiDAR systems use an active optical sensor that transmits laser beams and calculates the ranges and precise position of the target. Measurements are combined into a point cloud dataset, which is registered to a 3D-coordinate system. LiDAR technology is still relatively expensive compared with other safety sensors, including radar and cameras.

We aim to complete LiDAR surveys for parts of our overhead network during this AMP period. The surveys would use airborne LiDAR capture equipment to model our network.

The utilisation of LiDAR technology would improve the safety and predictability of our network operations, help us meet our safety objectives by identifying low ground clearances and assist us to predict the effects of adverse weather events through vegetation.

LiDAR data would input to our work towards an advanced network infrastructure model and enable faster overhead line designs and faster vegetation defect management and predictive growth rates on our network.

Business operations

As described in Section 5 of our AMP, our assets and operations business units (also defined in the ID Determination as system operations and network support) are directly responsible for the managing, operating, and meeting the demands on our network.

There are seven teams responsible for our asset management:

- Planning
- Asset Lifecycle
- Engineering and Standards
- Asset Information
- Customer Services
- Network Programme and Delivery
- Operations

As described throughout our AMP, the impacts of new technologies, DERs, EVs, climate change and sustainability are testing the traditional approach to our network assets and operations. These changes, combined with supporting our community's evolving needs, the delivery of the projects in this AMP, and our increasing focus on preparing for the future will result in an expanded remit for these teams. Data analytics and customer engagement are increasingly central to their roles, as will their contributions to meeting our regulatory requirements.

This will result in a need for increased resource and introduction of new capabilities within these teams over the period of this AMP.

These teams will play key roles in ensuring we can deliver to our AMP. During 2022/23 we invested in a core value chain optimisation project to evaluate our end-to-end processes and identify how we can become more efficient. This project highlighted the key improvement projects required which will commence during 2023/24 and continue throughout this AMP period. Some of the key initiatives that will be delivered include:

- Improving our new customer connections process
- Developing and implementing streamlined design standards
- Increasing the use of data analytics in our planning processes

Our property

Our property portfolio is primarily situated within Washdyke. We own the land and buildings at our main location, which consist of our corporate building, three sites leased to commercial tenants, as well as the offices, workshop and yard occupied by our subsidiary NETcon. In addition to this, within Washdyke we own two parcels of land as strategic investments to secure the footprint for future network expansions and one residential property, as well as one residential property in Twizel.

We do not expect significant uplift in property maintenance costs in this AMP period, based on the assumption that our buildings will continue to be used in the manner of their current purposes and be maintained to remain in its current state.

Our fleet

We own 19 vehicles to enable us to operate and maintain the network, deliver projects, engage with our community, and respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver.

We have an aging vehicle fleet, and we only have one EV in our current fleet. During this AMP period we will commence the development of our fleet strategy, which will include our considerations of replacing our current fleet with range appropriate EVs. Our AMP forecasts do not include any cost estimations other than the maintenance of our current fleet.

Business Support

Our business support teams include:

- **Safety and Risk:** identifies, assesses, and manages risks to the organisation and its stakeholders, as well as implementing safety programmes and procedures
- **People and Capabilities:** is responsible for the management of human resources and employee relations, including recruitment, training and development, compensation and benefits, and diversity and inclusion initiatives
- **Finance and Property Management:** manages the financial resources of our organisation, covering budgeting, financial reporting, and expenditure control
- **Regulatory and Sustainability:** ensures the organisation is compliant with regulatory requirements and promotes sustainability initiatives such as environmental protection, energy efficiency and waste reduction
- **Communications and Marketing:** communicates our vision, and values, whilst also promoting our services and brand to both internal and external stakeholders
- **Digital Services:** manages IT operations, data and analytics, infrastructure, cyber security, vendor management, partnership relations and digital innovations
- **Governance:** ensures compliance with laws and regulations and oversees the operations of the organisation through activities such as risk management and the development and implementation of policies and procedures
- **Programme Management:** manages the delivery of non-network change across the business, including strategic initiatives, process improvement, new system implementation and associated change management

Safety and Risk

Because we care for our people and our community ensuring everyone goes home safely every day is our number one priority. We recognise that with the increased work that we need to deliver during this AMP period comes increased risk. We have the following initiatives planned to be delivered during 2023/24, with ongoing improvements for future years:

- Development and implementation of a health and safety communication plan which will include:
  - Public safety campaigns
  - Community electrical safety education programme
  - Contractor network safety campaigns
  - Rural network engagement
- Development of a safety governance and reporting programme
- Increasing critical risk reviews across the business to identify any new critical risks and develop the critical controls needed to mitigate these risks
- Development and implementation of a Health and Safety Performance Development Framework, which will include:
  - A new safety roadmap
  - A strong focus on employee participation and personal ownership of safety
  - Ensuring quality support and expert advice provided to the business and contractors around safety
- Introduction of new Safety Assurance Programme, including internal and external safety auditing to provide assurance processes are understood, practicable and workable

A new position – Head of Safety – has been created within our Safety and Risk team. This role will be filled in 2023/24 and will lead these initiatives.

People and Capabilities

Our people are our greatest asset, and we are committed to continued investment in our people.

We will establish a dedicated Group Manager People, Safety and Performance role in 2023/24. This is the cornerstone to elevate the importance of the investment needed in our people to build and retain the resources and capabilities our business needs now and into the future. This will be a new position in our ELT.

Other initiatives we are introducing for our people in this AMP period include:

- Supporting our employee-led engagement and wellness ambassador programmes. These forums provide the opportunity for continued engagement and support, leading to a great community culture
- Introducing a new performance development framework in 2023/24. To meet our objective of a dynamic work environment, we need to build a high-performing culture where everyone's goals are well aligned with our strategy, creating shared accountability for their own and our collective success
- Launching our learning and development programme. Our people will only be able to adapt to the pace of change or adopt the necessary skills needed with strong support
- Developing our diversity and inclusion strategy. We are actively working to foster a culture of belonging and inclusion where all our people feel safe, valued, and included. To further enhance our efforts, we will be developing a comprehensive diversity and inclusion strategy. Our aim is to build upon the progress we have made and take meaningful steps towards a truly inclusive workplace
- Continuing to grow our student graduate programme by welcoming young minds into every business area to experience our industry and add innovative value through their contribution
- Supporting our Board, ELT and management teams, by continuing to develop the skills they need to lead our business into the future
- Development of our te Tiriti o Waitangi/the Treaty of Waitangi Framework to enable these principles to guide and inform our operations and business. This will include ensuring appropriate measures are taken to ensure Māori rights and interests are appropriately considered and acted upon where taonga (treasures) such as land, and personal data are concerned. We will also ensure we are creating a culturally safe and inclusive environment for Māori to fully participate and engage with our business, as employees, customers, and stakeholders

"Te Tiriti o Waitangi/The Treaty of Waitangi

Alpine Energy acknowledges te Tiriti o Waitangi/the Treaty of Waitangi as a founding document for Aotearoa, New Zealand. We acknowledge the principles of the te Tiriti o Waitangi/the Treaty of Waitangi."

Finance and Property Management

Our finance and property management team is well-established and we have invested heavily in this team and its capabilities over the last few years.

We do however have some initiatives planned for this AMP period to improve the efficiencies in this team including:

- Automation of the month-end financial close process
- Appointment of a management accountant to perform financial analysis and planning
- Streamlining our financial management processes and financial analysis tools to support our decision-making processes. This entails developing more comprehensive financial models as well as strengthening our cost analysis and forecasting methods

We have also identified the need to have finance business partners in our operational teams to assist with financial analysis and collation of information to flow into the financial reporting. These roles will be established and filled iduring this AMP period.

Regulatory and Sustainability

This team's responsibilities include:

- Pricing and pricing methodologies and roadmaps
- Compliance with the DPP and ID Determinations, which include the preparation of ID schedules, related party disclosures, DPP Annual Price-Setting Compliance Statement and DPP Annual Compliance Statement
- Billing and major customer support
- Monthly reporting on revenue and consumption patterns
- Analysis of new or changing regulations that may impact our business and providing information to the Board and leadership team on the proposed impacts and actions needed to respond to the new legislation
- Submissions to the Commerce Commission, EA, and other industry regulators
- Engagement with stakeholders on regulatory matters
- Development of our sustainability strategy
- Embedding sustainability into our business

Regulatory

In this next two years, the Commerce Commission is continuing the review of the IMs and the IDs and commencing the consultation process for the DPP4 reset. We also expect an increase in the consultations from the EA on pricing, emerging technologies, the role of EDBs in the energy future of New Zealand and the legislative reform needed to make all of this happen while not burdening the customer with additional costs.

With significant policy and legislative reviews underway in both local and central government, including district plan reviews, resource management reform, climate change legislation, the development of a nation Energy Strategy, and a central government election pending, we need to analyse, contribute, and respond to any regulatory changes impacting our business.

The increased activity in the regulatory space has highlighted the need for additional resources in this team to ensure that we can adequately assess and respond to the changes. We plan to appoint two more analysts into this team in the next three years to:

- Increase our data analytics on usage patterns based on smart meter data to develop a pricing strategy fit for the future and long-term benefits of the customers.
- Increase out capacity to lobby for the regulatory changes required to ensure that we are equipped for the future. This will include increased consultations, thought leadership and industry wide collaboration.

Sustainability

Our strategic pillar of sustainability confirms our commitment to work with the local community to improve South Canterbury's social, economic, and environmental wellbeing.

To support this pillar, we began developing our Sustainability Strategy during 2022/23. This strategy will centre around a commitment to be environmentally and socially responsible across our operations and provide leadership in sustainability within our region. This strategy will be completed during the next 18 months.

A central aspect of our strategy development has been carrying out a robust materiality assessment. We have engaged with both internal and external stakeholders to ensure that our strategy is underpinned by the issues most important to our people at Alpine, our shareholders, our other key stakeholders, and our communities.

In achieving our sustainability goals set as in our strategy and embedding these practices into our business will require investment in the right tools and technologies to capture, track and measure our performance and additional resources. We plan to add capability to help us capture and measure our carbon emissions. The scope of the technology solutions we will need has not yet been determined and we will include these in our future AMPs, informed by our sustainability strategy.

Our role in sustainability

While we are looking at our own business practices and processes through the sustainability lens, our role as a sustainability enabler is equally as important to us. We can, and already are, making a major contribution to Aotearoa New Zealand's decarbonisation efforts. We will continue to do so by effectively planning and operating our network to allow customers, both residential and commercial, to reduce their carbon emissions through projects including decarbonisation, DG, EV charger installations and energy efficiency initiatives.

Communications and Marketing

Our Communications and Marketing team's goal is to effectively communicate our messaging and values to the public, our employees, and stakeholders.

The appointment of an inhouse content creator in 2022/23 added the additional resource this team needed to deliver high-quality content that is creative, engaging, and in line with our brand.

This team has a critical role to play in our media campaigns to educate our communities on safety, keep them informed about outages, and responding to customer calls and queries.

This team also coordinates our sponsorship applications, makes recommendations to our Board and coordinates sponsorship events. Our sponsorship programme is one of the ways we live our vision of empowering our community and this team ensures that this is done in an equitable manner.

We are committed to establishing and maintaining open and transparent communication with all stakeholders. A formal communications and marketing strategy will be developed to ensure that it is effective in meeting our objectives and serving the needs of our stakeholders. This will also outline the necessary resources in terms of skills and tools required to transition towards a blend of digital and traditional marketing methods.

Digital services

Our digital services team is responsible for the development and delivery of our digital and data strategy. They are also responsible for leading the business in the selection and delivery, ongoing configuration, integration, and management of our information systems through our Digital Executive Governance Group.

Digital and data strategies

Our digital strategy has been in place for over two years, and we continue to align to our wider business strategy and associated initiatives. One of the aims of the strategy is to create a vision to identify opportunities for digital capabilities and solutions. Foundational work has already been put in place as part of the digital strategy including establishing our digital principles, delivering on a dedicated cyber security strategy, and adhering to a digital governance framework including new fit-for-purpose digital policies.

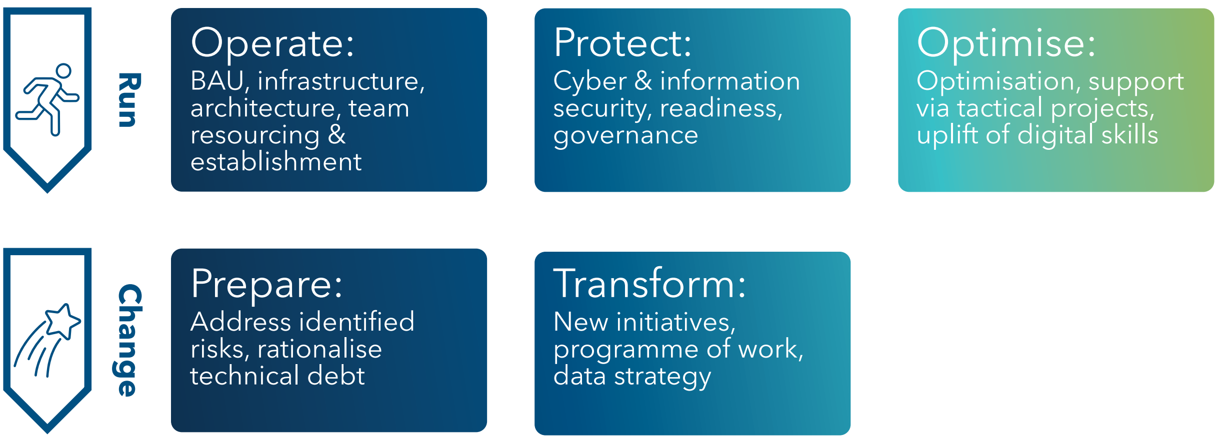
A digital strategy is more likely to succeed if an environment is created to help the ambitions and abilities of an organisation to work digitally. To do this we will continue to build our inhouse digital capability and use the right tools and training to uplift the digital literacy and fluency of our entire organisation.

> "The aim of our digital and data strategy is to facilitate our business's strategic pillar of treating our data as a strategic asset and using technology to transform our customers' and our people's experiences. This will transform the way we work to make the right decisions for our customers and our people."

We will leverage our established partnerships with industry peers and our digital partners to provide capability that we would not be able to deliver inhouse.

The initiatives that underpin our digital strategy have been refined as we understand more about the hurdles and opportunities ahead. As such, we have attempted to simplify our digital strategy roadmap into two high-level streams 'run' the business and 'change' the business:

- The 'run' stream includes our business-as-usual operations, infrastructure, and resourcing as well as our cyber security, readiness, and governance
- The 'change' stream includes the preparation required for our transformational initiatives e.g., rationalising our technical debt and any new projects or engagements such as our data strategy



Our data strategy will foster the creation of a data-driven culture, establish the governance of data used for analysis, define, and manage controls for master data and metadata management and ensure that business reports derived from controlled data are consistent and representative of the true state of the business.

A workable data framework and strategy will identify the core information required by the business.

There is significant value to us in capturing data on our network, our customers, and our environment. There is even more value in turning this data into information through robust analysis to support our future planning and decision-making.

For example, our assumption that peak demand will remain between 6am and 9am and 5pm and 9pm may be questioned in the future with shifting work patterns and more options for people to work remotely. Using real-time data will become crucial to effectively managing changing customer behavioural patterns and the subsequent load profiles across our network.

Our aim is to investigate the adoption of new technologies and approaches. These include a roadmap towards an implementation of a right-sized ADMS, and the use of data and analytics, e.g., from our smart meter data. Such new technologies and approaches will complement our continued investment in physical infrastructure to ensure we maximise the full potential of these assets.

Cyber security

Alongside our digital strategy, our cyber security strategy has also been in place for over two years, and significant work has been done internally and with our key partners to move toward the objectives of sound enterprise architecture practices, informed and trained employees and an adherence to critical infrastructure industry frameworks.

Our cyber security strategy and the industry frameworks that we follow are based on good practice principles including having a strong identity foundation, protecting data in transit and at rest, keeping people away from data, applying security to all layers, mechanising security practices, ensuring traceability and preparing for security threats.

We have an associated programme of work which underpins our cyber security strategy. Recent deliverables include the upgrade of our comprehensive endpoint protection against ransomware, malware, and phishing sites and an OT security posture assessment.

Planned deliverables include a firewall rule refresh, a penetration test with a defined scope and the implementation of a managed Security Operations Centre (SOC) alongside a Security Information Event Management (SIEM) platform.

Other key initiatives

This team has a critical role to play in transforming the way we work and will have also deliver other key initiatives during this AMP period, including:

- Reducing our technical debt by 50% via best practices and migrating to updated technology by 2025
- Establishing a security operations centre to uplift industry framework capabilities and cyber roadmap items in 2023/24

Governance

Our governance team is responsible for our full compliance calendar and all interactions with our Board and assisting Directors to meet their obligations. Their responsibilities include:

- Managing all correspondence with Shareholders
- Managing regular updates during the year including an Annual General Meeting
- Leading our policy steering committee ensuring our policies are kept up to date
- Ensuring internal compliance including reviewing policies at the required intervals

The key initiatives this team will deliver in during this AMP period are:

- Development and implementation of a digital compliance calendar
- Development and implementation of a policy framework
- Establishing of internal committees to manage reporting to the Board

Programme management

Our programme management team was established in 2022. The delivery of our strategy is a key focus area for us during this AMP and this team will be responsible for managing the delivery of our strategic initiatives and other key programmes of work.

The team will manage the delivery of non-network change across the business, process improvement, new system implementation and associated change management.

Innovation practices

We have been making several innovations to our electricity network to enhance asset management and provide a secure and reliable supply of electricity to South Canterbury. The table below highlights our key innovations and improvements

Innovation	Description	Driver	Success Measures	Timing	Other implications/ comments
Innovation projects and practices underway					
Drone AI	Utilising drone technology to assess vegetation clearance of lines, condition rating and monitoring of poles and cross arms. The AI will identify the components and update data in our Asset management system.	Direct maintenance activities to high priority areas and reduce risk.	Direct maintenance activities to high priority areas and reduce risk.	2022/23	This will deliver faster inspections of our overhead network.
Satellite data	Utilising satellite data and overlaying it on our overhead network, for vegetation management and continual identification of high-risk areas on the network.	Faster identification of vegetation risks on the network.	Improved vegetation management.	2022/23	Faster identification of vegetation risks on the network.
Remote switching	Increased installation of remote switching.	Improved safety practices.	Improved safety practices.	2022/23	Reduced exposure to potential arc flash.
Segmented based scheduling project	Using data analytics to segment and prioritise forward maintenance planning to optimise works delivery.	Improved maintenance efficiency.	Aligned programmes of work based on optimised inspection schedules.	2022/23	This will deliver faster inspections and aligned maintenance activities.
Innovation projects and practices planned for during the AMP period					
Increased utilisation of smart meter data	We have 88% smart meter coverage on our network, and we will continue to utilise the data on our LV network develop improved forecasting and modelling techniques for the future.	Facilitating customer choice and reducing costs.	Improved forecasting and modelling techniques, real-time identification of power quality problems, optimised network investment to facilitate increased uptake of EVs.	2023-25	Ensure our LV network can facilitate the increased uptake of EVs through optimised network investment.

10. **Risk and resilience**

Risk and resilience

Managing risk and building resilience is particularly important within our current operating environment. The challenges and uncertainties we face and the significant increase in regulatory and works programme delivery requirements, demand and innovation requires a robust risk management approach.

This section outlines our risk context before turning to our approach to risk management, the frameworks we operate within and the key risks to our organisation, assets, and service delivery. We also explore how we treat these risks to minimise, where possible, the residual risk. Our emergency management responsibilities and our role as a lifeline utility provider are also discussed in this section. Finally, we outline our changing approach to resilience, and the need to build it into everything that we do.

Risk overview

As an EDB, our risk context is complex and dynamic. This has been further emphasised by the significant damage to electricity infrastructure and supply during recent severe weather events in the North Island. But recent years have also taught us the importance of considering risks beyond our network, our region, and New Zealand.

The following examples have all in some way exposed new or elevated risks to our business:

- Significant and increasingly costly extreme weather events across New Zealand
- The Covid-19 pandemic
- The Russian-Ukrainian war
- Global inflation
- High-profile cyber-attacks in New Zealand and cyber-attacks on critical infrastructure globally
- The ramping up of national and international climate change policy and action

Reflecting on the lessons of the past few years, our stakeholders and customers expect us to have robust risk management processes, and for these to be communicated appropriately to help inform their own risk management.

Our local risk context

- Scientific research by Te Herenga Waka - Victoria University indicates that there is a 75% probability of an Alpine Fault earthquake occurring in the next 50 years, with an 82% change that it will be a magnitude 8+ event which would likely have a significant impact on our infrastructure
- Our region experiences cold winters and is subject to weather extremes including snow and high wind events, especially in the Mackenzie District
- The frequency of high wind events in South Canterbury is projected to increase as a result of climate change
- Urban clean air restrictions on solid fuel heating sources across our region has resulted in an increased reliance on electricity for home heating
- Our network spans several rivers prone to flooding during north-west weather patterns. The frequency and severity of north-west flood events for Canterbury rivers are projected to increase because of climate change
- Parts of our network, including infrastructure connecting large industrial customers, are within coastal high hazard erosion and inundation areas

Our risk management policy

The purpose of risk management is the creation and protection of value. It improves performance, encourages innovation, and supports the achievement of objectives.

We believe that good risk management is iterative, dynamic, and forward-looking. The aim of our risk management policy is to provide assurance that risks are being prudently and soundly managed and that treatments are considered effective to the best of everyone's knowledge and experience.

This policy establishes how we view our exposure to risk as well as the administrative, human, and financial resources necessary to mitigate risks before they happen. We need to make sure that if a risk is accepted, it is done deliberately and not in ignorance.

The objectives of this policy are to ensure that:

- This policy is consistent with ISO 31000:2018 Risk Management – Guidelines
- Risks are within our risk appetite threshold or, accepting that not all risks can be mitigated to be within the agreed risk appetite threshold, they are assessed and approved consistent with our delegated authorities and our risk management policy

Risk management responsibilities

We operate both a top-down and bottom-up approach to risk management. At the top level, the Board sets the risk appetite and strategic direction for our business. Our board has established an Audit and Risk Committee and a Health and Safety Committee, both of which assist in fulfilling responsibilities to protect the interests of shareholders, customers, employees, and the communities in which we operate. The committees provide the following:

- Oversight of our risk policies and practices
- Monitoring of risk performance concerning risk appetite and business objectives
- Guidance regarding the development of the risk framework
- Rigorous processes for internal control and legal compliance

While visibility and dedicated commitment to risk management by our executive and management teams is key, successful risk management requires the ownership and involvement of our whole team.

Our risk management framework

We have commenced work to refresh our risk management framework to facilitate the identification of strategic and operational risks and the resources necessary to mitigate these risks before they occur. Our refreshed enterprise risk management framework will assist us in improving performance, encouraging innovation, and achieving our strategic goals.

The framework will also ensure that we can adhere to the risk management process outlined in our Risk Management Policy.

Our risk management process

Our risk management processes are designed to occur at different levels, and divided into strategic and operational risk management. Strategic risks will be overseen by the Audit and Risk Committee and ELT. Operational risks will be overseen by the operational business units with support from the management team and ELT.

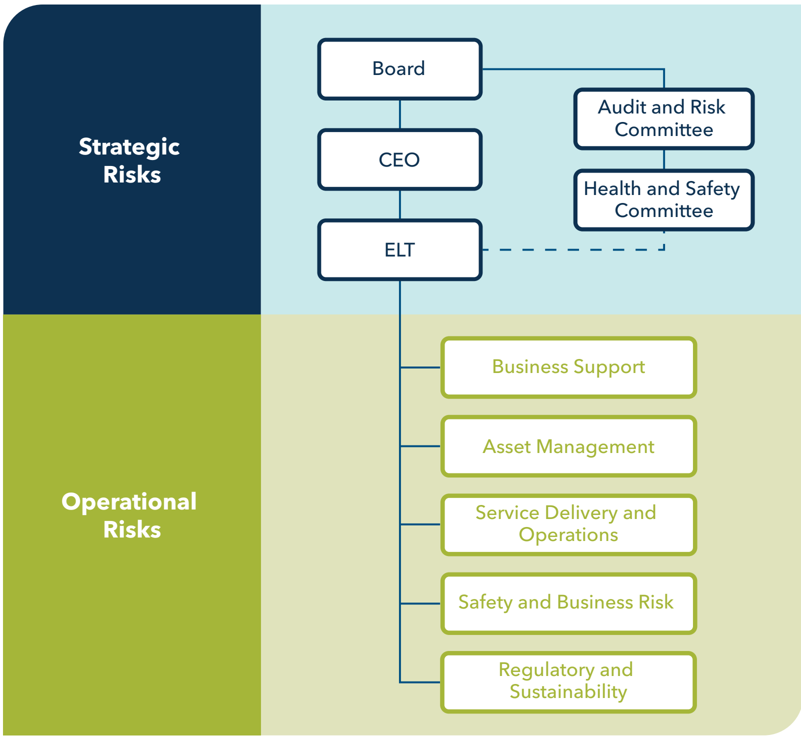


Figure 1: Risk Responsibilities.

We will adopt the risk management process as represented in ISO 31000 Risk Management – Principles and Guidelines below. It involves the systematic application of policies, procedures, and practices to the activities of communicating and consulting, establishing the context and assessing, treating, monitoring, reviewing, recording, and reporting risk.

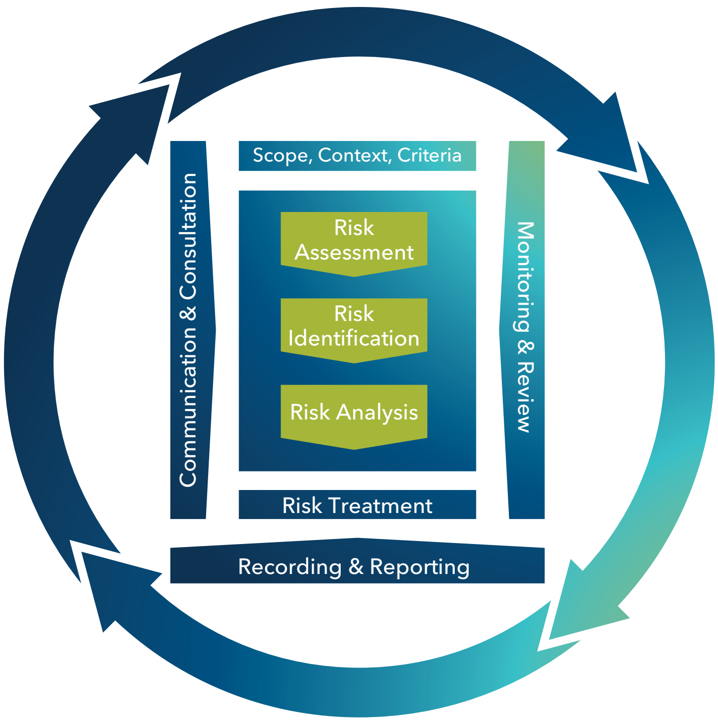


Figure 2: Risk management process in accordance with ISO 31000.

Risk assessment incorporation

During 2022 we formed a Works programme committee (WPC). The purpose of this committee is to enhance our decision-making on how and when we do projects, using a risk-based approach. The committee comprises of technical experts from across our business to ensure that we make decisions based on all work that is required to maintain, upgrade, and grow our network. The committee is responsible for:

- Compiling the annual works programme in alignment with the Asset Management Policy
- Overseeing the implementation of the works programme
- Proposing the budget needed to carry out the projects
- Ensuring that our decisions are well-informed, transparent, and aligned with our business objectives

With reference to our risk management policy, projects are allocated a risk percentage. To assess the risk, we use the methodology of likelihood and consequence in line with the requirements of our Risk Management Policy. This approach helps us to identify and mitigate potential risks effectively, enabling us to deliver successful projects. By involving a diverse range of stakeholders in the WPC, the committee is better equipped to manage both strategic risks associated with our assets and project-related risks that may arise throughout the asset lifecycle. This collaborative approach ensures that we can effectively identify and mitigate risks, resulting in successful project outcomes and a resilient network.

Asset investment decisions consider the risk rating to ultimately ensure that the health and reliability of our network assets remain acceptable and that projects are prioritised accordingly.

When assessing the risk associated with a project, the committee considers the inherent risk associated with not delivering, or deferring, a network project against network and non-network criteria including the following:

- Health and Safety (public, staff, and contractors)
- Meeting stakeholder expectations
- Meeting customer expectations
- Non-compliance with our SoSS
- Exceeding equipment ratings (including SCADA alarms and protection settings)
- Insufficient quality of supply (voltage levels, harmonics, flicker, power factor)
- Replacement and renewal requirements
- Environmental damage or concerns
- High Impact Low Probability (HILP) Risk
- Strategic risk if not prioritised

The final risk rating is also dependent on the availability and feasibility of investment options to reduce the inherent risks to a tolerable or acceptable level. The committee will consider network and non-network solutions as part of the assessment process. These options can be a combination of network and non-network solutions:

Network solutions:

- Operational activity
- Non-asset solution
- Influence / Educate customers / consumers
- Construct DG
- Modify an asset
- Retrofitting
- Install new assets

Non-network solutions:

- Demand side management
- DG
- Emerging technology
- Energy storage

High impact, low probability risks

High Impact, Low Probability (HILP) risks pose a significant threat to our electrical distribution network and are defined as rare, but significant events that will impact a large number of ICPs for an extended period. Managing HILP risks on an ongoing basis is critical for us to ensure our network remains resilient and can recover from these events in a prompt, but safe and reliable manner.

We consider the impact of HILP events when assigning risk ratings and prioritising projects in our works programme. This ensures that we appropriately prioritise the projects that will ensure our network resilience when HILP risks do eventuate.

The table below provides examples of events that we consider to be HILP and some of the mitigations that we have in place to manage and plan for these events.

HILP event	Major asset failure at a critical site causing widespread supply loss	Extreme weather events and natural disasters damaging our assets, causing accessibility issues and impacting our critical workforce	Widespread health event impacting critical workforce	Serious safety event at a critical site resulting in access issues or shut down periods for investigations	Cyber-attacks causing widespread failure of our critical systems
Examples	• GXPs Zone substation transformers • Switchboards	• High winds • Heavy snowfall • Floods • Earthquakes	• Global pandemics	• Serious injury or fatality (either the public or our employee or contractor)	• Failure of SCADA system
Mitigations	• We have procured and developed backup diesel generation plants and a mobile substation • Major event planning • Complying with SoSS, ensuring N-1 at all critical sites where possible • Collaboration and support from other EDB's	• The development of a network climate resilience strategy is planned for this AMP period • Considering climate related events in the risk assessment for project prioritisation • Critical spares and resources available for emergency response	• Ongoing revision of pandemic policies and response plans by ELT and Board • Work from home practices and strict hygiene protocols • Segregation of critical control room staff	• Risk management policy • Safety committee with safety representatives • Regular site visits • Site safety audits	• Cyber security controls • Control room contingency planning

Event management and emergency response

We are a lifeline utility, as defined by the Civil Defence and Emergency Management (CDEM) Act 2002, providing essential services to the community. Our responsibility as a lifeline utility is to be able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency.

We plan for a range of events which could impact on our service delivery, from natural hazards events such as extreme wind, wildfires, earthquake, heavy sustained rain, dry years, or heavy snow, to technical hazards such as major electrical plant failure or a cyber security event.

Emergency response plan

This plan follows the principles and processes described as the Four Rs of emergency preparedness as defined in the CDEM Act 2002 and provides information to our people to ensure that we are ready to respond to, and recover from, significant major events which may threaten the continuity of power supply and compromise the safety of the public.

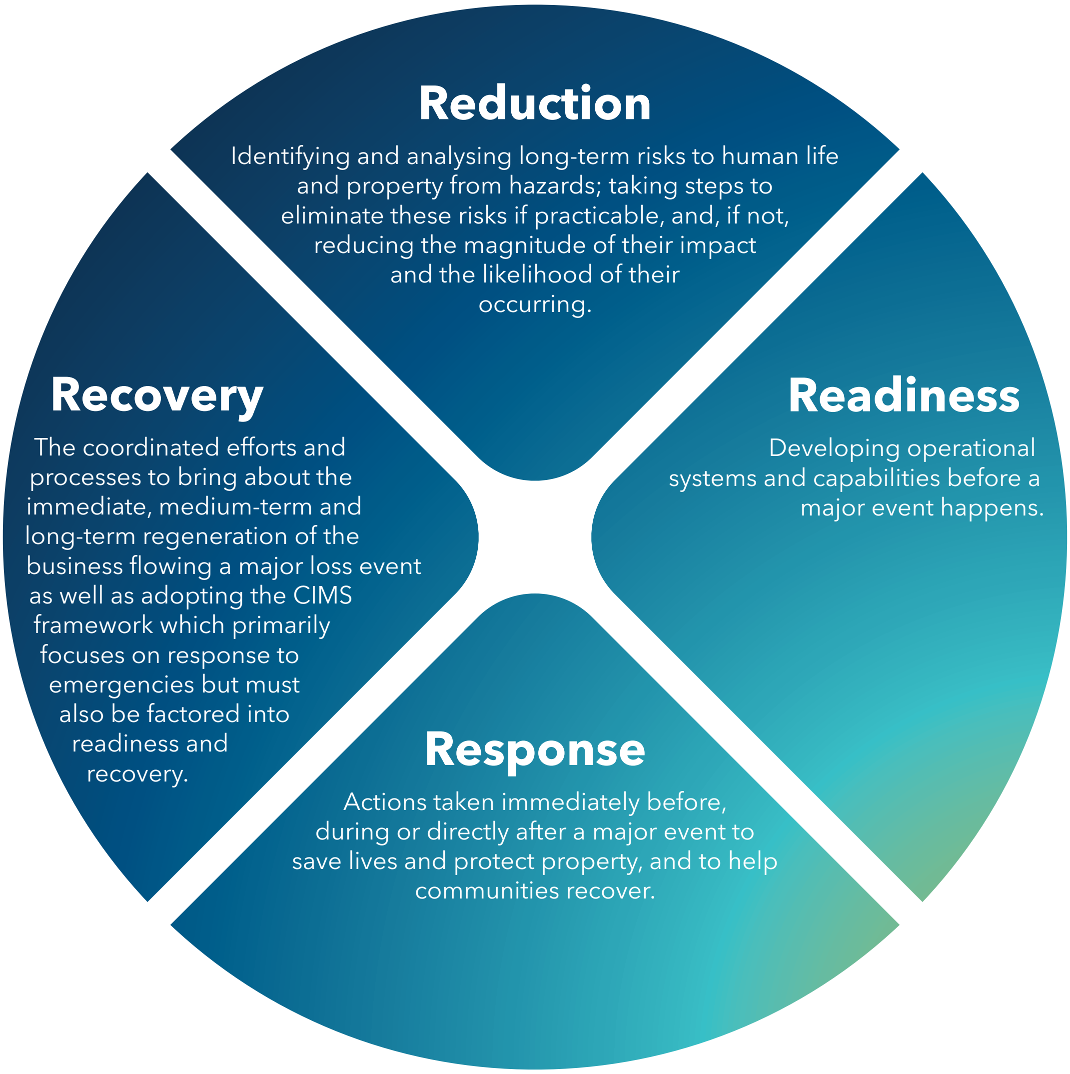


Figure 3: Emergency Preparedness Four Rs.

The Emergency Response Plan also includes the responsibilities of each of the roles in the emergency response team to ensure that our teams appreciate exactly who is responsible for what in the event of an emergency.

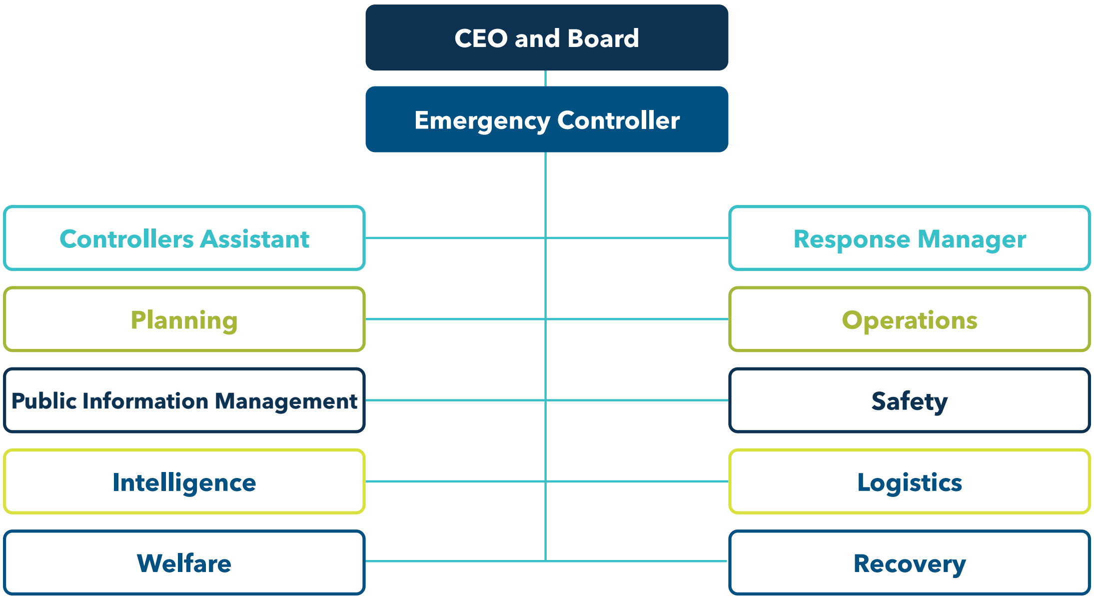


Figure 4: Emergency Response Structure.

Business continuity management policy

This policy is designed to provide a systematic approach to manage any adverse event and to establish basic principles for ensuring the prompt recovery of operations that have been interrupted for any reason. It defines the business continuity responsibilities of our Board, ELT, and management teams.

Crisis communication plan

We have an informal crisis communication plan in place to govern the approach to communications and external relations during a crisis, emergency, or business continuity events. We will be formalising this plan during 2023/24.

Participant rolling outage plan

For electricity dry year events we have a Participant Rolling Outage Plan (PROP) detailing how we would response to a situation should there be a need for rolling outages across our network. The plan complies with legislative requirements in Part 9 of the Code as well as the System Operator Rolling Outage Plan (SOROP). The plan highlights the priority of our feeders based on the type of users. The plan also details the communications plan between us and the System Operator.

Switching plans

We have restoration switching plans developed for each zone substation at a feeder level, to ensure prompt restoration in the event of an emergency.

South Canterbury Lifeline Utilities Group

We are part of the South Canterbury Lifeline Utilities Group (as a subfunction of the Canterbury Group) and continue to work and collaborate with all the agencies to ensure alignment and coordination for optimum emergency response outcomes for our communities. Current work within our Lifeline Utility Group includes the Mid-South Canterbury Alpine Fault magnitude 8 (AF8) plan.

Alpine House

Alpine House is built to Importance Level 4 (IL4). This means that the building is designed to remain operational following a 1 in 500-year seismic event. The building is also equipped with a standby generator, which can provide back-up power to our operations hub in the event of power loss for up to one week. This is a key component of restoring critical electrical supply to our communities.

Our resilience

The resilience of critical infrastructure networks is central to our ability to deliver safe, reliable electricity to our communities. Although often discussed in terms of climate change, resilience covers a range of risks and responses.

Nationally, resilience planning and management has gained additional focus and attention following the Christchurch and Kaikoura earthquakes and the growing awareness of the impacts of climate change. Reviews of infrastructure at a national level and identification of other risks such as cyber security have increased the focus on building resilience into all infrastructure planning.

The National Disaster Resilience Strategy and Rautaki Hanganga o Aotearoa | The New Zealand Infrastructure Strategy 2022-2052 provide information and guidance on resilience planning.

The National Disaster Resilience Strategy sets three priorities to improve our nation's resilience to disasters:

- Managing risks: what can we do to minimise the risks we face and limit the impacts to be managed if hazards occur
- Effective response to and recovery from emergencies: building our capability and capacity to manage emergencies when they do happen
- Enabling, empowering, and supporting community resilience: building a culture of resilience in New Zealand so that everyone can participate in and contribute to communities' – and the nation's – resilience

Resilience is an important component of our asset management planning processes. With a range of uncertainties across our business and the energy sector, we accept that we must improve our resilience to be in the best position to respond to future change and shocks. Our role as a lifeline utility provider is a key component of building a resilient nation.

Embedding resilience into our business

Our planned responses to the key strategic influences summarised in Section 1 that are embedded in this AMP; decarbonisation, decentralisation and extreme weather events - will assist us in the ongoing development of organisational and physical asset resilience plan. We acknowledge that we have some work to do to develop our resilience framework and plan. During the period of this AMP, we will be focussing on:

- Operational planning and responses to improve resilience
- Organisational awareness of the changing risk environment with the adoption of strategies, asset management practices and planning to improve resilience
- Organisational engagement with climate change risks and adaptation strategies
- Continued engagement in regional and district engineering lifelines workstreams
- Engagement with Transpower on risk and resilience workstreams, and associated infrastructure investment and development where needed
- Infrastructure development to support national decarbonisation objectives provides the opportunity to provide additional network resilience
- Network decentralisation will improve resilience
- Extreme weather event awareness, modelling, infrastructure, and operational response planning will improve resilience

In addition to our initial steps to building resilience into our infrastructure, services, and organisation, we will continue to be involved in enabling, empowering, and supporting community resilience through awareness education, social media channel use, sponsorships, and involvement in a broad range of community events.

Improving the resilience of our organisational and physical asset resilience is an ongoing programme of work. Milestones and achievements will be noted in our future AMPs.

11. What we need to spend on our network

What we need to spend on our network

The step change required to adapt our network and services to prepare for our future environment will require a significant increase in investment over the next 10 years and beyond.

This section describes the forecast CAPEX and OPEX required to deliver the plans outlined in our AMP for the next 10 years, and details the key projects we plan to deliver this year. We also highlight the changes from the previous AMP and why the changes are needed.

Overview

The forecast expenditure is based on the best information available at the time of publishing our AMP, noting that several assumptions were made in determining the forecasts (as outlined in Section 3). These forecasts are impacted by some variables outside of our direct control and therefore will change over time as we gain more certainty on demand and supply, regulatory changes, new technologies and other macro-economic conditions.

All data and graphs in this section are presented in the constant prices (as in schedules 11a and 11b in Appendix D). Our 10-year budget has allowed for inflationary increases as reflected in the nominal prices presented in schedules 11a and 11b in Appendix D (refer to Section 3 for our inflation assumptions).

Network CAPEX

The total forecast network CAPEX for the 10-year planning period, is presented below. We have budgeted according to our prudent scenario described in Sections 6 and 7.

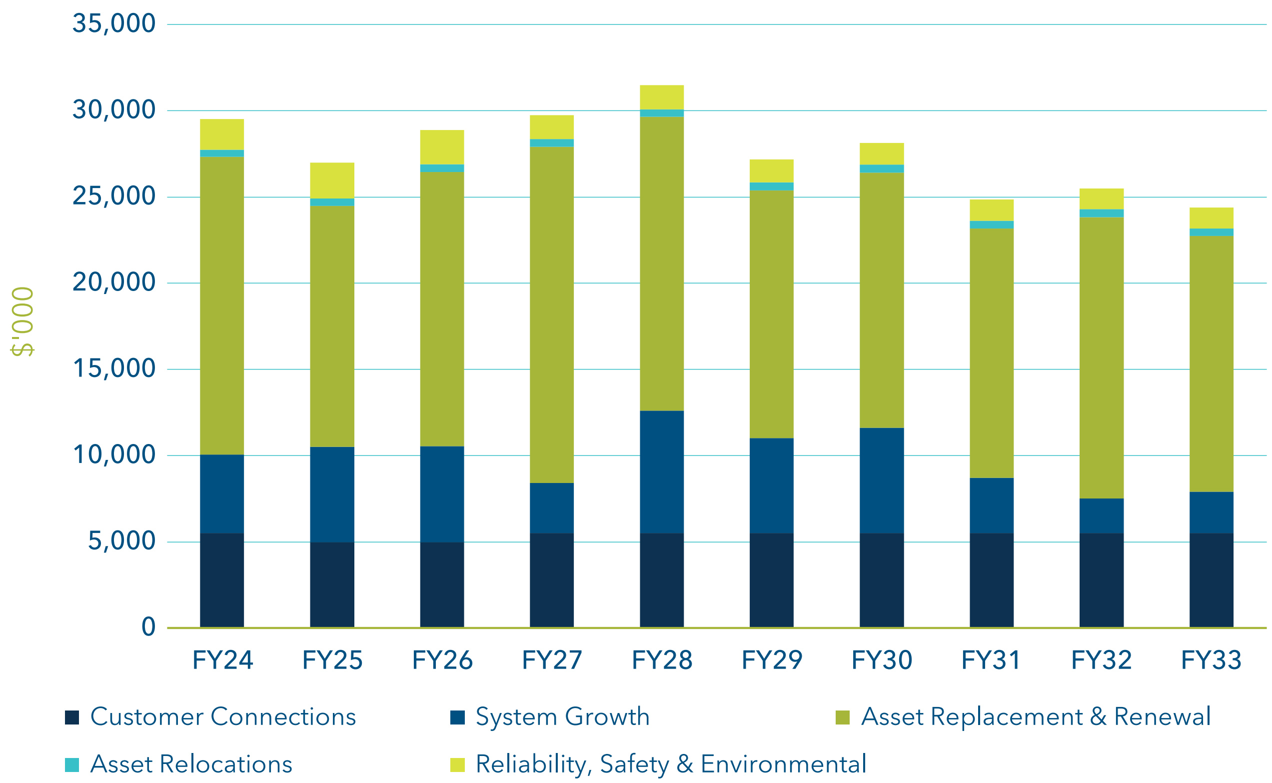


Figure 1: Total CAPEX by category.

The increase in network CAPEX for this 10-year planning period reflects the influence of our key investment drivers discussed in Section 3. As our AMP attests, we are in a period of strong growth and with our current capacity constraints we need to make significant investments to ensure that we can connect new customers and enable decarbonisation and electrification in South Canterbury, while maintaining our service levels. Ongoing inflationary and resource pressures also contribute to the uplift in CAPEX, specifically for the first year of the planning period.

In comparison to our previous AMP, these forecasts present a step-change in the network CAPEX required as shown in Figure 2 below.

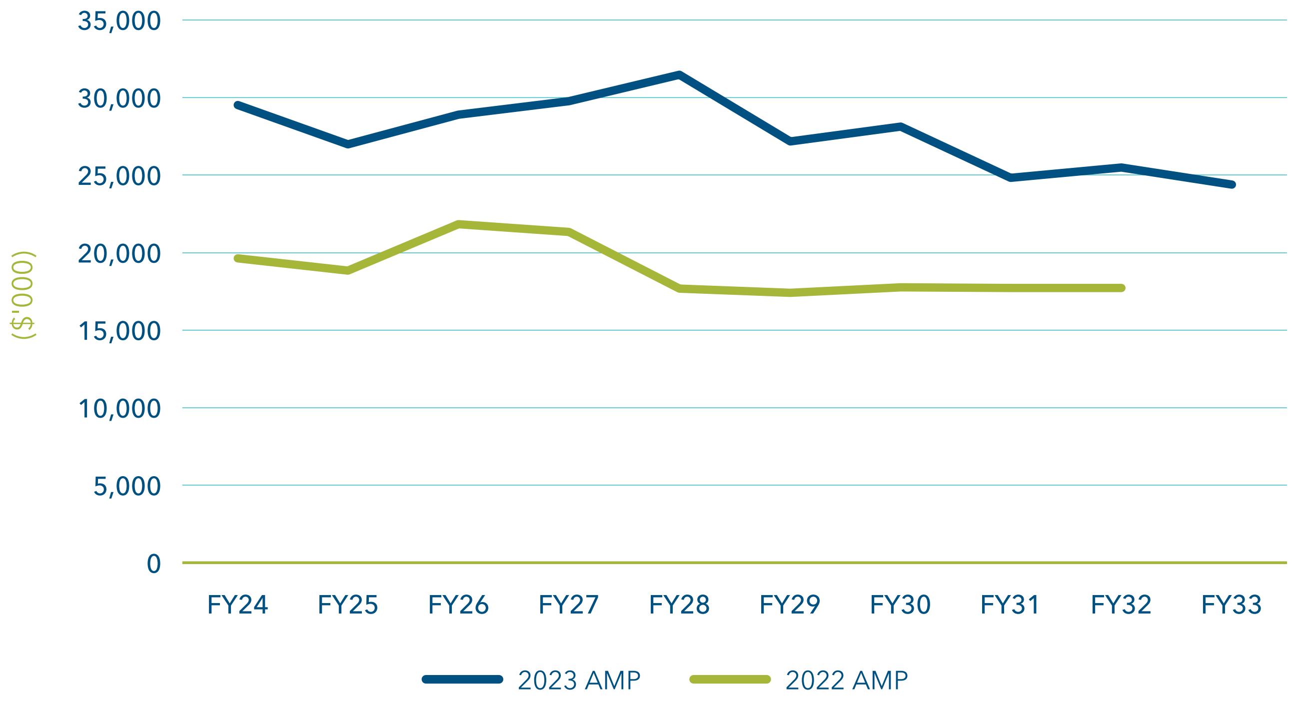


Figure 2: Network CAPEX - 2023-33 AMP versus 2022-32 AMP.

The table below shows the variance by network CAPEX category from the 2022-22 AMP for the overlapping nine years (FY24 – FY32). The largest variances are in relation to asset replacement and renewal, system growth and customer connections.

Variance in Forecast Capital Expenditure [$ '000]									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Customer Connections	1,000	600	1,900	2,200	2,200	2,100	2,050	2,010	1,965
System Growth	3,930	3,940	180	-2,260	6,290	4,390	4,190	1,490	290
Asset Replacement & Renewal	5,872	2,765	4,435	8,245	5,695	3,425	3,740	3,200	4,950
Asset Relocations	-1,710	-550	-550	-550	-1,175	-550	-400	-350	-280
Reliability, Safety & Environmental	810	1,415	1,090	785	810	420	800	760	840
Total	**9,902**	**8,170**	**7,055**	**8,420**	**13,820**	**9,785**	**10,380**	**7,110**	**7,765**

Material projects

This section details the material projects that are primarily driven by a need for renewal or replacement, load growth, or improvement of SoS. These projects are either already underway or are to be started in the first half of the planning period. We have defined material projects as those projects where:

- The expenditure is more than $500k
- The project will be replacing critical assets
- Where a lack of this expenditure could have a high consequence on our ability to supply electricity to customers

Project type	Description	Estimated cost ($'000)	Timing (FY)
Overhead line renewal/ replacement projects	These projects will replace and renew more than 300 kilometers of overhead lines (or 3900 poles) across our network. This will ensure we continue to maintain a safe and reliable network.	6,670	2024
Network portion of customer connections	Network changes will be required to facilitate forecast load growth due to industrial, commercial, and residential growth.	500	Annually
Overhead line removal between Grants Road and Luxmoore Road, Timaru	Relocate the overhead line running over private property with an underground network. This project will provide improved resilience for the Timaru urban network.	1,500	2024/25
Twizel Village Zone Substation rebuild - Phase 2	Started in 2022/23, the Twizel Village Zone Substation project replaces end-of-life assets. Replacement of all 33kV and 11kV switchgear, installation of new protection equipment, and the relocation of the existing transformer. This will improve SoS at the substation.	3,360	2024
Washdyke Switching Station upgrade	Upgrade the capacity of the Washdyke switching station to enable forecast load growth due to electrification of industrial process heat and growth. This is the first stage of a larger project over this planning period which includes the construction of a new substation in 2025 and supporting cable work. This will create approximately 30MW additional capacity for the Washdyke area.	4,000	2024
Underground substation replacement programme	Annual programme to replace three or four underground substations with above ground equivalents. The underground substations are moved to above ground so that the risks of confined spaces, old equipment failing, and electrocution can be removed. This programme will continue until the remaining 28 underground substations have been replaced.	1,200	Annually
Maintenance Defects	Programme to respond to network defects identified through condition-based monitoring and inspections in the field. This work will support the ongoing safety and reliability of our whole network.	1,450	Annually
Transformer Replacement	This project will replace the 20MVA 33kV/11kV transformer at our Clandeboye substation. The transformer suffered a failure in 2023.	994	2024

Variance from 2022-32 AMP

Last year's AMP showed a 10-year network CAPEX forecast of $170 million, which has now increased by $107 million to $277 million over the same period. The main factors contributing to this increase are summarised in the table below.

Project description	Forecast Change ($'000)
Economic growth leading to an increase in new customer connections. Approximately $11M of this will be budget will be recovered from customer contributions.	16,300 (-11,000 recovered)
Development of two new substations and supporting cable work at Washdyke to support industrial decarbonisation and growth.	9,800
Development of new Timaru Port Substation and supporting cable works to able work to support load growth from transport electrification and industrial decarbonisation.	7,000
Prepare North Street Substation for a potential upgrade to 33kV that will resolve capacity constraints, support future EV growth and improve network resilience.	1,600
Replace end-of-life substation equipment at Twizel, Tekapō and Hunt Street Substations.	7,400
Replace end-of-life transformer at Clandeboye 1, Pleasant Point and Fairlie Substations.	4,000
Increase in overhead lines projects as a result of condition-based monitoring.	10,110
Replacement of aging distribution substation transformers, switchgear, cables and equipment across the network.	22,160
Sub-transmission cable replacements.	2,800
Increase inspection and replacement of aged LV boxes due to fire risk.	7,380
Asset relocations forecast has been reduced due to no forecast relocations within planning period.	-6,120
Total	**82,430**

Non-network CAPEX

The total forecast non-network CAPEX for the 10-year planning period is presented below.

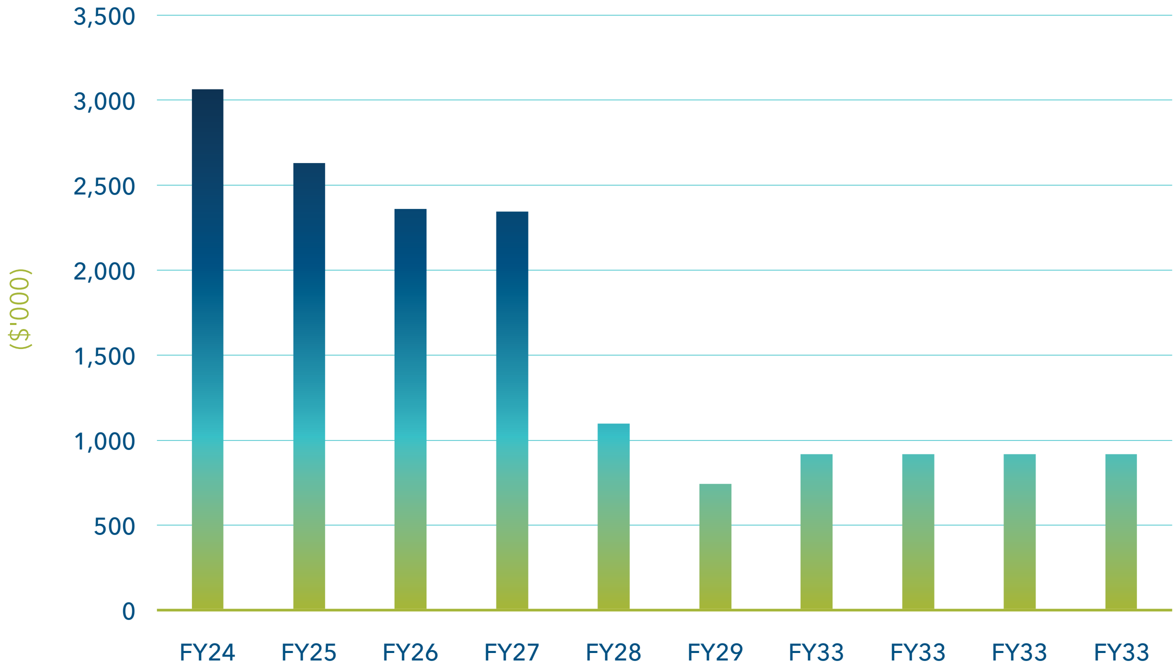


Figure 3: Non-network CAPEX.

The non-network CAPEX profile aligns with our forecast expenditure for digital tools required to support and run our network over this planning period. Our investment in digital is explained in detail in Section 9.

In comparison to our previous AMP, these forecasts present a step-change in the non-network CAPEX as shown in Figure 4 below.

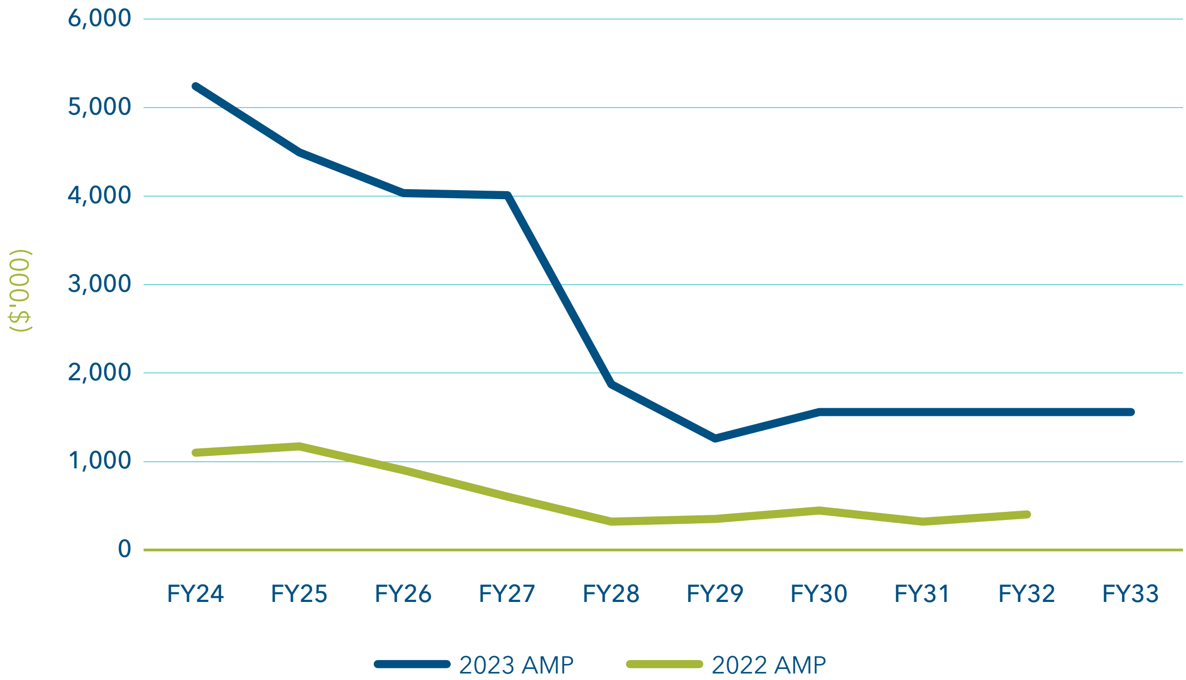


Figure 4: Non-network CAPEX - 2023-33 AMP versus 2022-32 AMP.

Last year's AMP showed a forecast of $5.6 million for the nine overlapping years (FY24 - FY32), which has now increased by $20 million to $25.6 million. The main contributing factors to this increase are summarised in the table below. None of these projects were included in the 2022-32 AMP forecasts and therefore all represent a variance from the prior year. The significant variances are detailed below.

Project/Investment	Forecast Change $'000
Remote control and automation of our network Faster restoration times, decreasing unplanned SAIDI and increased customer satisfaction and improved safety operations.	2,900
Implementation of ADMS This project will improve our outage restoration times, create efficiencies in daily network operations and improve distribution reliability.	5,600
Implementation of LiDAR technology This project will provide a data point model of our network which will improve the safety and predictability of our network operations, planning, and vegetation management processes.	2,250
Future-state ERP The on-premises version of our current ERP will no longer be supported as of October 2024. An investment decision as to the future of our ERP solution and modules will be aligned with our future-state architecture and data strategy decisions.	2,850
Future-state technology architecture By investing in a redesign of our existing systems, applications and integrations, we can improve the efficiency and reliability of our current systems and inform future business investment decision-making.	1,550
Data strategy implementation This project will support improved data insights and decision-making. It will establish the management of data as a business asset, exploiting data using research and analytics to maximise the return on data assets.	1,550
Value chain redesign This project will implement solutions to improve the efficiency of our core operations.	1,800
Total	**18,500**

Network OPEX

The total forecast network OPEX for the 10-year planning period, by category, is presented below.

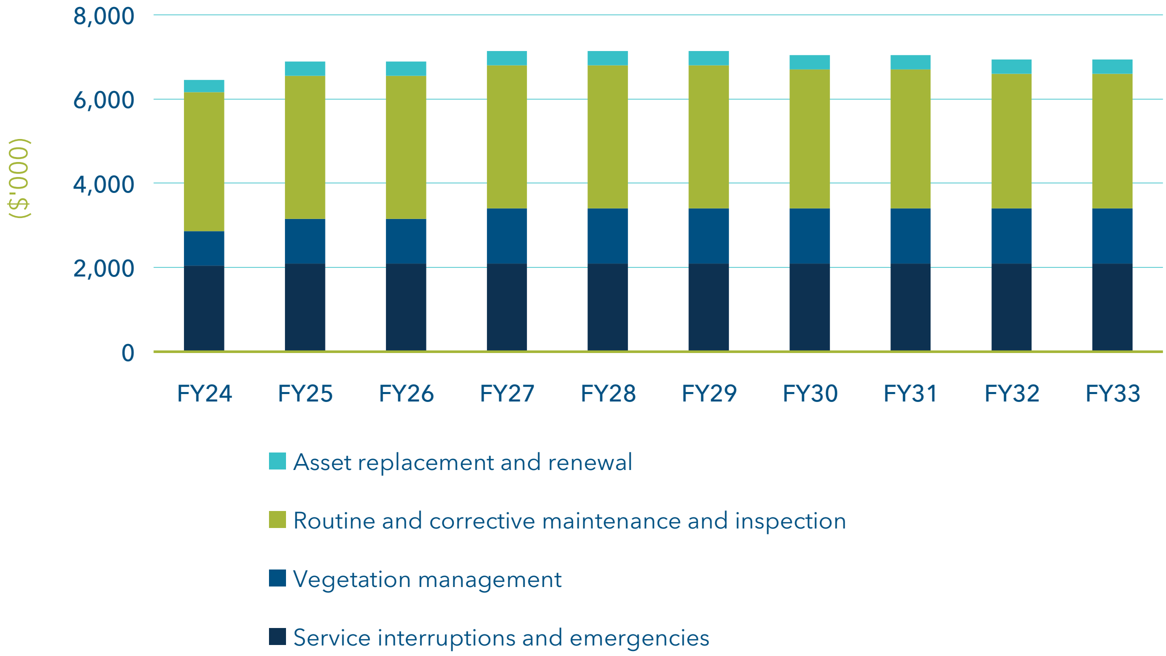


Figure 5: Total network OPEX by category.

Last year's AMP forecast $58.4 million for the nine overlapping years (FY24 - FY32), which has now increased by $4.8 million to $63.2 million as shown below.

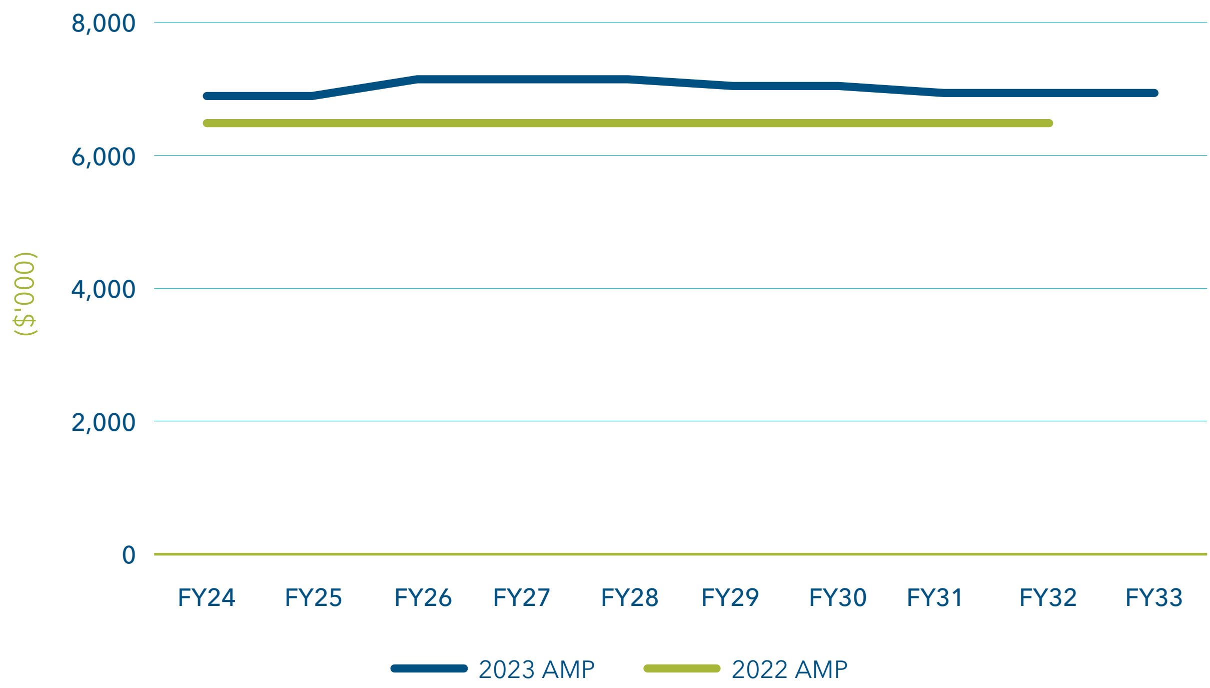


Figure 6: Network OPEX - 2023-33 AMP versus 2022-32 AMP.

The table below shows the variance by network OPEX category from the 2022-32 AMP to the 2023-33 AMP for the overlapping 9 years (FY24 – FY32).

Variance in Forecast Network OPEX [$'000]									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Service interruptions and emergencies	55	55	55	55	55	55	55	55	55
Vegetation management	230	230	480	480	480	480	480	480	480
Routine and corrective maintenance and inspection	70	70	70	70	70	-30	-30	-130	-130
Asset replacement and renewal	52	52	52	52	52	52	52	52	52
Total	407	407	657	657	657	557	557	457	457

The larger variance in vegetation management is due to cost increases and work to support our reliability targets. Over the past year, the contracting rate for an arborist has increased by 15%, necessitating a corresponding increase in our vegetation budget. We are also planning to boost the frequency of vegetation inspections along our 33kV lines from annually to bi-annually.

Non-network OPEX

The total forecast non-network OPEX for the 10-year planning period, by category, is presented below. Business support costs are allocated at 88% of total business support costs, in line with the allocation method disclosed in Schedule 5g of our IDs for 2022.[9]

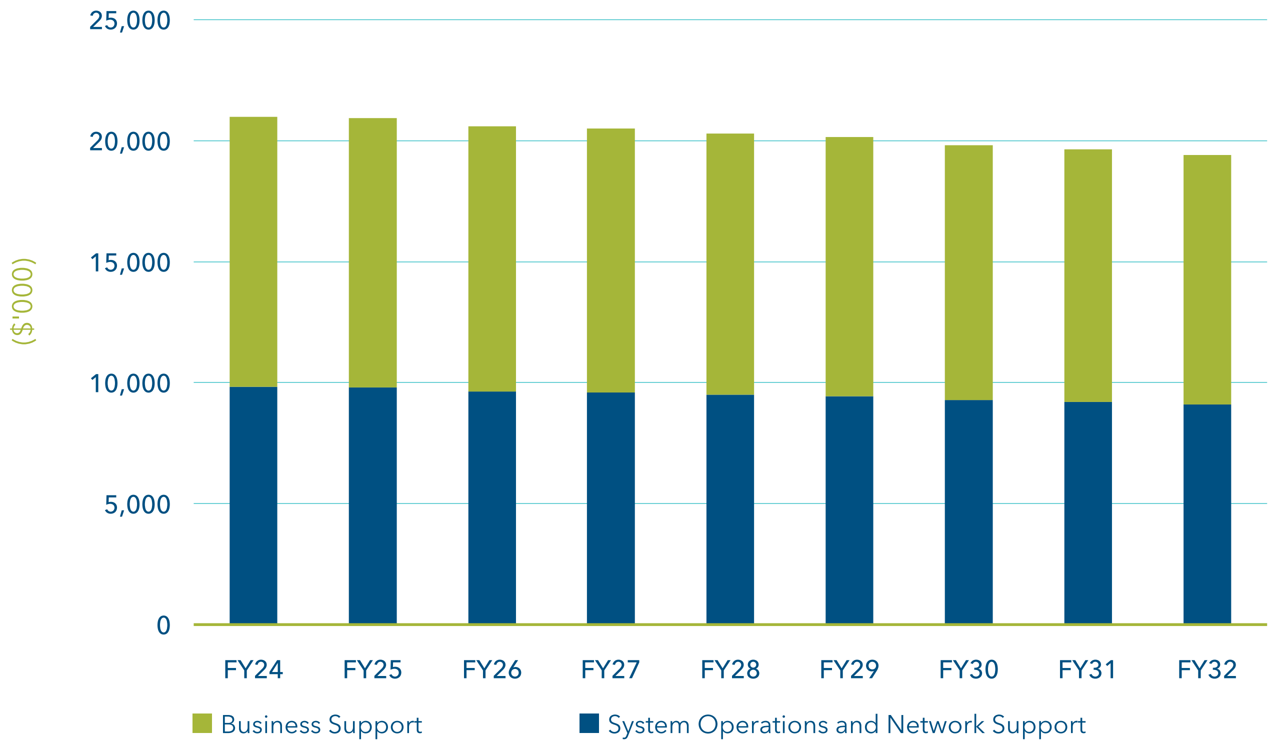


Figure 7: Non-network OPEX.

[9] Alpine Energy Limited, Information Disclosure Schedules, period ending 31 March 2022.

The non-network OPEX forecast for the 10-year planning period closely aligns with:

- The delivery of our network programme. As explained in this AMP, our network CAPEX will increase significantly over the next 10 years. We also forecast an increase in new customer connection requests (and customer contribution revenue) for the 10-year planning period. The administrative support required to ensure that the network programme is delivered will increase
- Investment in our risk management practices. As we increase work on our network, we need to ensure that our risk management practices are best in class to ensure our people and contractors go home safe every day
- Investment in digital and data. As explained in Section 9, the investment in our future-state technology architecture and data strategies will be a priority over the coming years
- Investment in our people and the capabilities we need to manage our future network. We will appoint new positions into the business over the next 10 years to ensure that we have the right capabilities, but also the resources to deliver our strategy and network programmes, while ensuring that we have proper succession planning in place for our ageing workforce. Key appointments over the next 12 months will also ensure that we can pro-actively participate in the regulatory consultations led by the Commerce Commission and EA, including reviews of IDs, IMs and the DPP4

If the 2022-32 AMP correctly reflected the categorisation and the allocation of BS costs, the difference would be as follows:

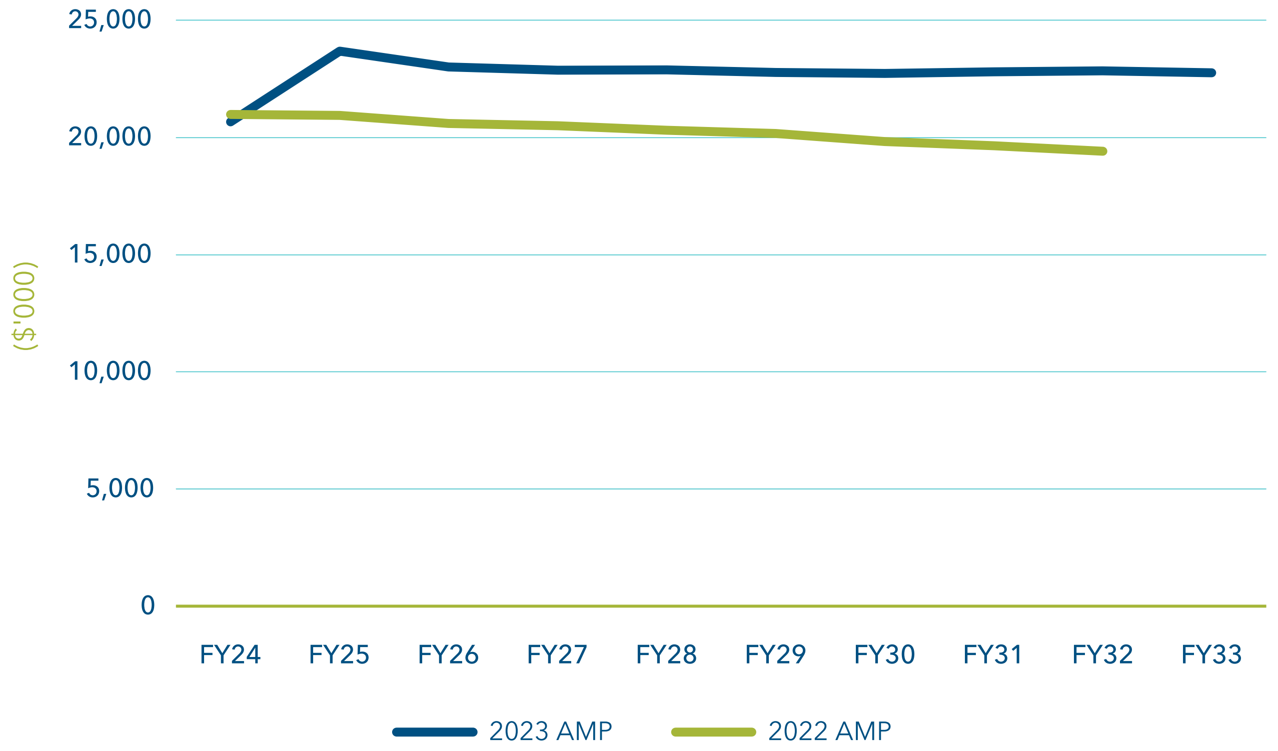


Figure 8: Non-network OPEX - 2023-33 AMP versus 2022-32 AMP.

12. How we will deliver our AMP

How we will deliver

Mature asset management incorporates processes, systems, capabilities, and capacities to deliver and enhance operational efficiency. We continuously monitor and improve our asset management processes to enhance our planning and service delivery.

Delivering capital projects presents significant difficulties due to changes in our industry and community. To overcome these challenges, we must adopt new work methodologies and establish effective monitoring and evaluation systems. Successful delivery of our AMP works programme depends on having experienced and skilled resources internally and with our service providers. The availability of adequate resources is crucial for the delivery of our planned capital and operational expenditure, responding to customer-initiated work, and managing network faults, and emergencies.

This section covers two important elements of our AMP – how we plan for successful delivery, and how we measure our success. It provides an overview of the processes we will use to manage and deliver our capital, operations, and maintenance works programmes. This section also outlines our works programme delivery process. This process enables us to deliver high-quality work safely, efficiently, and on schedule with a focus on cost efficiencies.

Building our capacity

As we prepare for the delivery of this AMP, we recognise that we have facing a dual difficulty; a works programme of increasing scale and complexity, paired with the talent shortage identified in our strategy.

Across this AMP period we will need to increase our internal skills, capabilities, and capacity across all functions of our business to effectively enable decarbonisation, decentralisation, and digitisation. To attract and retain top talent, we need to be innovative in our recruitment methods and offer our employees benefits that meet their changing needs.

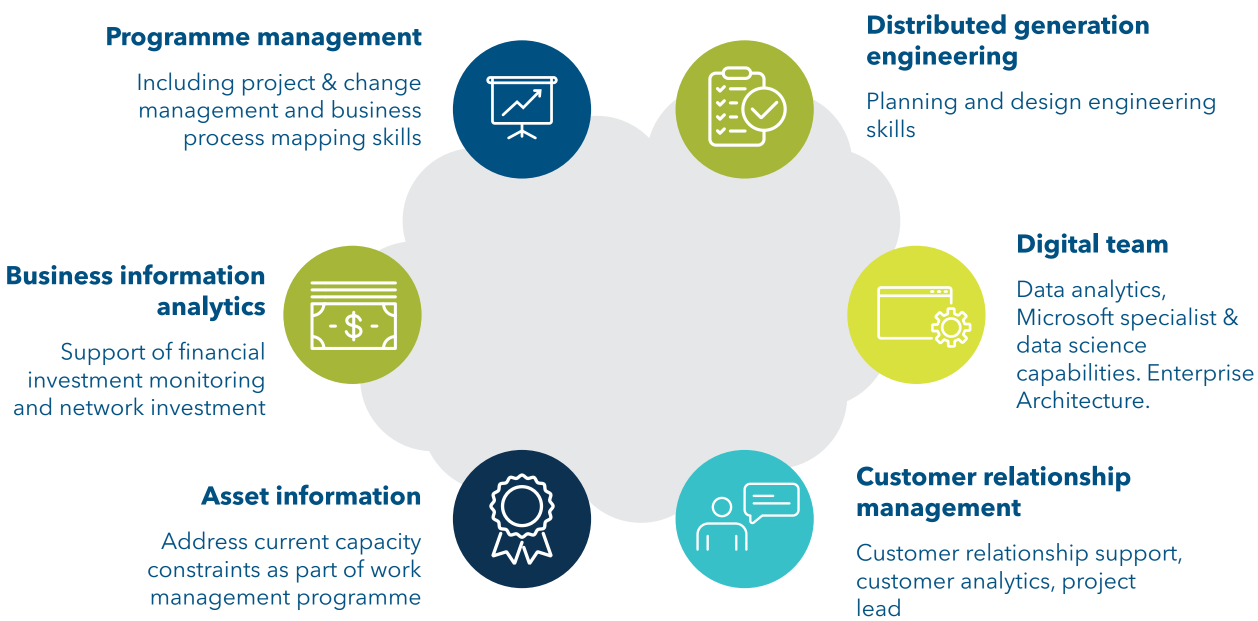


Figure 1: Resourcing and capability requirements.

We are also very aware of our reliance on well-resourced service delivery partners to deliver our AMP. To achieve this, we will collaborate closely with our service partners, other EDBs and industry bodies to develop capacity and capability across our industry. We will explore opportunities to promote employment and training through summer holiday and graduate programmes, attendance at trade and skills expos, and engaging with schools and universities.

Delivery overview

Our Service Delivery Team are responsible for ensuring the successful delivery of our works programmes. Key elements of successful delivery include:

- Maintaining the highest safety standards in work execution
- Managing relationships with service delivery providers
- Meeting operational deadlines and financial targets

Our inhouse project management professionals work collaboratively across our business and with customers and service providers, tailoring the delivery of work to achieve the best possible outcome for our network and our customers.

Capital works delivery

We have well defined and embedded processes for the delivery of capitals works across our network

Identification: we consider the network requirements discovered through defect reporting, load studies, and customer work requests.

Justification: we undertake a risk assessment, perform a load study, and forecast demand, carry out a feasibility study, and develop the project scope and cost projection.

Design: we establish a project team, conduct a site survey, consult with internal and external stakeholders, identify, and appraise assets, finalise the scope and cost projection, and review the risk analysis performed thus far. SiD review precedes the comprehensive design. Long-lead equipment will be ordered during this stage to minimise risk of supply chain delays.

Procurement: we tender for construction during this stage and prepare contract documentation and job pack information. We may also procure additional equipment and materials required.

Delivery: While the construction of the physical works is now the responsibility of the service provider, we continue to manage the project, establishing cost, schedule and quality performance monitoring, ongoing risk and issue management. When construction is completed, the asset will be commissioned, and the project closed out.

Maintenance works delivery

Our principal service provider, NETcon carries out the majority of maintenance tasks across our network, operating under an approved rate card system and a Master Service Agreement (MSA). NETcon is contracted to handle all fault response work across our network.

Under the MSA, we have defined responsibilities, obligations, and key performance indicators for scheduled work. In addition, we maintain a library of technical standards that our contractors must comply with when carrying out their duties.

Maintenance projects are tendered in a manner similar to capital works projects, and their delivery is closely monitored by our Service Delivery and Asset Lifecycle teams. We conduct regular, independent reviews and verifications of rate cards for prescribed activities.

As part of our maintenance specification activities, we evaluate the outcomes of maintenance delivery works, including costs, equipment condition and performance, . This enables us to identify areas where our maintenance requirements can be improved and provide advice that will address reliability and performance risk. For further information on our maintenance requirements, please refer to Section 8.

Customer initiated work

Our Customer Services team manage the identification, scoping and feasibility stages of customer-initiated projects such as subdivisions and commercial and industrial connections. The procurement and delivery stages are managed by our Service Delivery team, with physical works being completed by the customers chosen service provider.

Section 4 covers our customer connection practices in more detail.

Major projects

Major projects are predominately works identified in the AMP, however, some large customer connection works are also delivered as a major project. We use inhouse project management, through our Service Delivery team.

Where appropriate we tender electrical elements of a major project separately to the specialist and civil works. Though this process we are able to generate competitive tension, helping projects remain within budget and supports high-quality delivery from contractors.

To help our contractors manage their workflows, especially for major projects, we now provide a forward works programme at least four months prior to the beginning of the financial year. This also helps ensure the delivery of our full works programme.

Delivery of significant works programme

To meet anticipated future demands, while maintaining reliability and safety, we are forecasting a significant increase in the scale and complexity of capital expenditure projects is required over the next several years. However, our forecast expenditure needs to be tempered by our ability, and our service providers ability to deliver planned work programmes. With an already tight labour market, and low unemployment contributing to staff capacity and recruitments issues, our strategy identifies that the threat of local skills shortages puts our ability to deliver at risk.

Recognising this, during this AMP period we will focus on developing our delivery capabilities and efficiencies. We will pair this with programme delivery practices designed to deliver cost and time efficiencies and minimise customer and community disruption, including:

- Regular engagement with the three territorial councils, other utilities provides including Chorus, and Waka Kotahi (the New Zealand Transport Agency) to align projects and identify shared efficiencies where possible
- Utilising inhouse project management expertise and planning and scheduling our works programme in a collaborative, risk-based manner through our internal Works Programme Committee
- Being a member of the South Island Buying Group, which combines the buying power among South Island EDBs, with a view to secure the best material prices
- Close collaboration between Procurement and Engineering functions internally to align equipment and material requirements to maximise efficiency in our supply chain
- Early engagement with customers and stakeholders to coordinate works with seasonal and local events, such as farming seasons, manufacturing shutdowns, school holidays and local events

Measuring our success

This section sets out how we measure our performance. While we have regulatory measures which we must track our performance against, we also report on our achievements against the targets we set.

Our customers and stakeholders have consistently told us that safe and reliable electricity supply is a top priority. And so safety and reliability are key service measures. In line with our strategic refresh, over the next year we will be developing a robust performance management framework with key performance indicators aligning with our strategic goals. This will ensure we are able to monitor not only core services, but also the delivery of our strategy.

Our current performance indicators

We closely monitor our performance against service levels and annual budgets and through a set of performance indicators. These indicators include safety and reliability performance.

We measure our performance against a range of health and safety, network reliability and financial targets. The performance targets that have been set for the period covered in this AMP are outlined below.

Our health and safety targets

We have a responsibility to keep our people, our contractors and the public safe from serious injury involving any of our equipment and at all our sites. Public safety awareness campaigns help us to educate our community to ensure everyone is kept safe every day.

	2023/2024	2024/2025	2025/2026
Business safety			
Number of serious injury events involving AEL Group employees or our service providers	Nil	Nil	Nil
Number of lost time injuries	<2	<2	<2
Number of recordable injuries	<4	<4	<4
Public safety			
Number of serious injury events involving members of the public	Nil	Nil	Nil
Number of public safety awareness campaigns	10	10	10

Leading Safety metrics for 2023/24	Metric
Public Safety Management System (PSMS)	
• External PSMS assessment	Recertification
• Media comms planned vs. delivered	>90%
• Public safety observations (Safety and Culture forum members)	20
• Public harm accidents from our network (excl. car vs. pole)	0
• Public safety engagement meetings	12
Safety Conversations per year	
• Board of Directors	24
• Executive Leadership Team	60
Safety Observations per year	
Operational Business units	140
All other employees (one observation per employee)	>60%
Corrective actions	
• No corrective actions open more than 60 days	0
Safety training	
• Percentage of training courses planned vs. completed	>85%
• Percentage of new employees to attend Intro Entry Approval Certificate course (non-operational employees)	>75%
• Percentage of new employees to complete NZQA US6402 (First Aid)	>75%
Safety culture	
• Organisational safety culture (maturity)	Complete first assessment to benchmark

Network reliability performance targets

SAIDI and SAIFI are standard industry measures for network reliability. SAIDI and SAIFI Performance Measures are calculated in accordance with the Commerce Commission's DPP Determination. The SAIDI and SAIFI limits are set and fixed during each five-year regulatory period, for planned and unplanned outages respectively.

Commerce Commission have yet to set the limits for the fourth regulatory period, commencing 1 April 2025 and we have therefore only included the next two years in the performance targets below.

	5-year limit
Planned SAIDI	824.87
Planned SAIFI	3.4930

	2023 /2024	2024 /2025
Unplanned SAIDI	124.71	124.71
Unplanned SAIFI	1.1970	1.1970

Figures 2 and 3 below show our actual SAIDI and SAIFI performances for the previous five years, as well as the regulatory targets for 2024 and 2025. Targets beyond 2025 will be determined as part of the DPP4 reset.

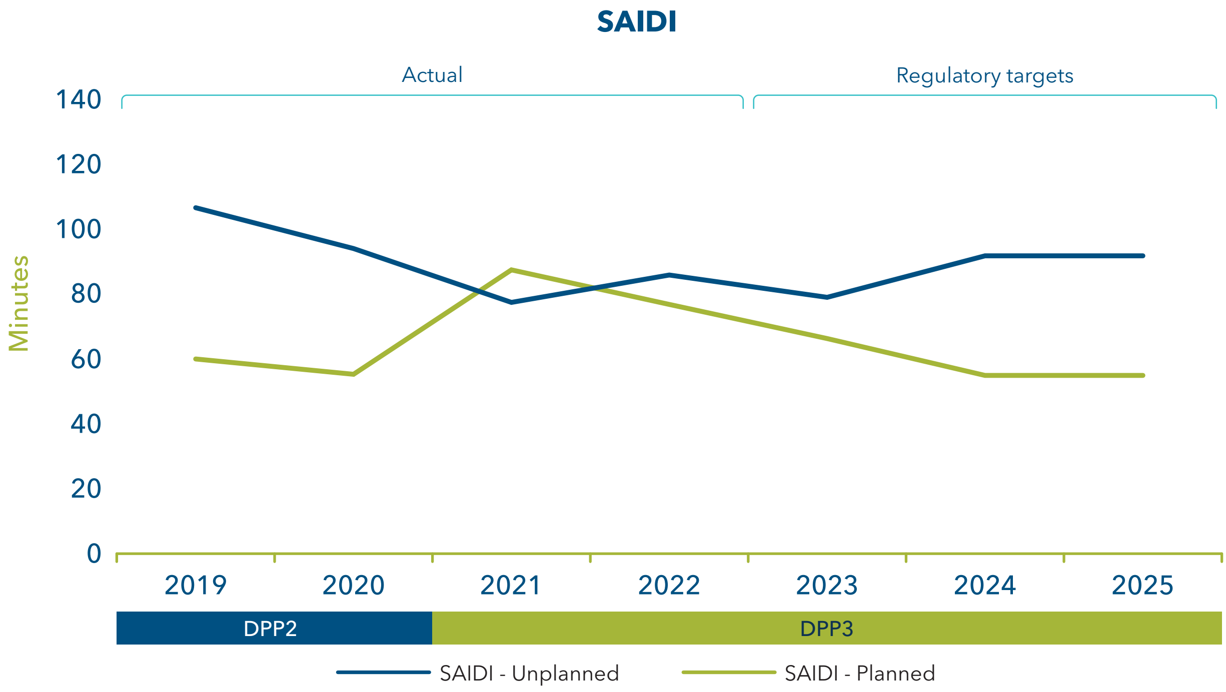


Figure 2: SAIDI performance and targets 2019-2025.

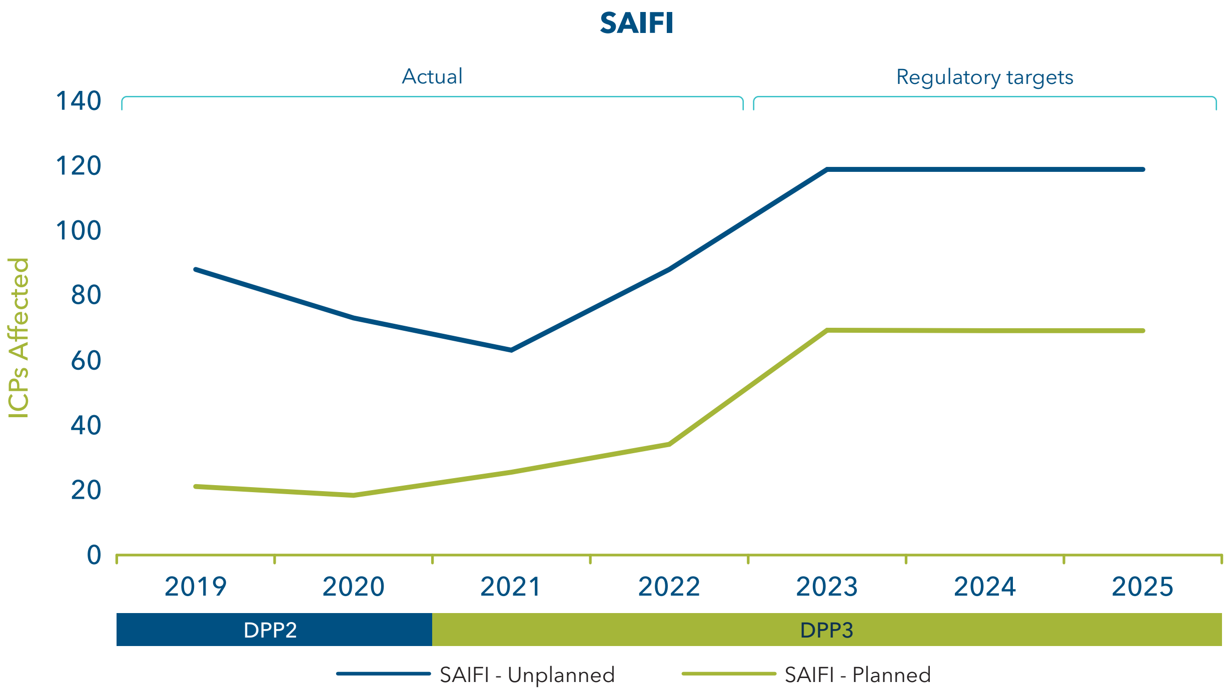


Figure 3: SAIFI performance and targets 2019-2025.

Regulatory and legislative compliance

As a non-exempt EDB we adhere to the requirements set by the Commerce Commission, including IDs and the DPP. Complying with these regulations is essential as they play a major role in determining our network reliability and impacts the revenue we earn from electricity distribution.

We adhere to relevant regulations and directives, including resource consents, the Health and Safety at Work Act, and the Electricity (Safety) Regulations, amongst others. We also follow guidelines, such as those published by the EEA, that ensure that we meet industry standards.

Service provider performance

We audit our service providers using an audit management guide by our service delivery team, supported by external experts as appropriate. Our audit process allows for the identification of health and safety hazards, contractual and technical non-conformances.

Our key objective when monitoring performance is continuous improvement including:

- Ensuring our customers are satisfied and that our projects are coordinated where possible to minimise power outages
- Ensuring positive relationships with service providers
- Consistent reporting and tracking of contract performance indicators

13. Appendices

Appendix A: Glossary

A	Ampere
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
ABY	Albury Grid Exit Point
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management Systems
AF8	Alpine Fault earthquake (magnitude 8)
AHI	Asset Health Indices
AMF	Asset Management Framework
AMI	Advanced Meter Interface
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
AMS	Asset Management System
AR	Asset Relocation
ARR	Asset Replacement and Renewal
BAU	Business as usual
BESS	Battery Energy Strorage System
BPD	Bells Pond Grid Exit Point
CAPEX	Capital Expenditure
CBARM	Condition-based Asset Risk Management
CBs	Circuit Breakers
CBD	Central Business District
CC	Customer Connection
CEO	Chief Executive Officer
The Code	The Electricity Industry Participation Code (2010)
CRM	Customer Relationship Management
DB	Distribution Box
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DNP3	Distributed Network Protocol
DPP	Default Price-Quality Path (as per the Commerce Commission Determination)
DSM	Demand-side Management
EA	Electricity Authority
EAM	Enterprise Asset Management module
ECM	Enterprise Content Management
EDB	Electricity Distribution Business
EEA	Electrical Engineers' Association
EECA	Energy Efficiency and Conservation Authority
ELT	Executive Leadership Team
ERP	Enterprise Resource Planning
ETAP	Electrical Power System Analysis software
EV	Electric Vehicle
FMECA	Failure Modes, Effects and Criticality Analysis
FY	Financial Year
GIDI	Government Investment to Decarbonise Industry Fund
GIS	Geographic Information System
GWh	Giga Watt hours
GXP	Grid Exit Point
H1	Asset Heath Indices rating: end-of-life
H2	Asset Heath Indices rating: material failure risk
H3	Asset Heath Indices rating: increasing failure risk
H4	Asset Heath Indices rating: normal deterioration
H5	Asset Heath Indices rating: as new
HV	High Voltage
HVDC	High Voltage Direct Current
ICP	Installation Control Point
IDs	Information Disclosures (as per the Commerce Commission Determination)
IED	Intelligent Electronic Device
IMs	Input Methodologies (as per the Commerce Commission Determination)
IT	Information Technology
KP	Karl Pfister joint
kV	kilo Volt
kVA	kilo Volt Ampere
LBS	Load Break Switch

LCI	Labour Cost Index
LiDAR	Light Detection and Ranging technology
LV	Low Voltage
MED	Timaru Municipal Electricity Department
MEP	Metering Equipment Providers
MSA	Master Service Agreement
MVA	Mega Volt Ampere
MW	Mega Watt
N	Reliability measure: if the network cannot deliver electricity after the failure of one line, cable or transformer
N-1	Reliability measure: where the network can still deliver electricity after the failure of one line, cable or transformer
NDP	Network Development Plans
OCB	Oil Circuit Breakers
ODID	Outdoor to Indoor conversion
ODV	Optimised Deprival Valuation
OMS	Outage Management System
OPEX	Operating Expenditure
OT	Operating Technology
PG	Parallel groove
PILC	Paper Insulated Lead Cable
PPE	Personal Protective Equipment
PPI	Producer Price Index
PSMS	Public Safety Management System
PV	Photovoltaic (solar)
PVC	Polyvinyl chloride
RMU	Ring Main Unit
RSE	Reliability, Safety and Environment
RTU	Remote Terminal Unit
SaaS	Software-as-a-service

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCEPB	South Canterbury Electric Power Board
SCI	Statement of Corporate Intent
SF6	Sulphur Hexafluoride gas
SG	System Growth
SiD	Safety in design
SIE	System Interruptions and Emergencies
SNA	Significant Natural Area (as per District Plans)
SoS	Security of Supply
SoSS	Security of Supply Standard
SPS	Special Protection Scheme
STU	Studholme Grid Exit Point
Sub	Substation
SWER	Single-wire Earth Return
T1	TechnologyOne (Enterprise Resource Planning solution)
TDHL	Timaru District Holdings Limited
TIM	Timaru Grid Exit Point
TKA	Tekapō Grid Exit Point
TMK	Temuka Grid Exit Point
TWZ	Twizel Grid Exit Point
V	Volts
VCB	Vacuum Circuit Breaker
VLF	Very low frequency
VSD	Variable Speed Drives
WPC	Works Programme Committee
XLPE	Cross-linked Polyethylene Cable

Appendix B: AMP information disclosure compliance

INFORMATION DISCLOSURE DETERMINATION REQUIREMENT

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
1	**Core: The core elements of asset management–**	
1.1	A focus on measuring network performance, and managing the assets to achieve service targets;	Section 12
1.2	Monitoring and continuously improving asset management practices;	Section 5
1.3	Close alignment with corporate vision and strategy;	Section 5
1.4	That asset management is driven by clearly defined strategies, business objectives and service level targets;	Section 5
1.5	That responsibilities and accountabilities for asset management are clearly assigned;	Section 5
1.6	An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets;	Section 8
1.7	An emphasis on optimising asset utilisation and performance;	Section 8
1.8	That a total life cycle approach should be taken to asset management;	Section 5
1.9	That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	Section 9
2	**Requirements: The disclosure requirements are designed to produce AMPs that–**	
2.1	Are based on, but are not limited to, the core elements of asset management identified in clause 1 above;	Section 12
2.2	Are clearly documented and made available to all stakeholders;	Section 3
2.3	Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets;	Section 1
2.4	Specifically support the achievement of disclosed service level targets;	Section 12
2.5	Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment;	Section 8, 9
2.6	Consider the mechanics of delivery including resourcing;	Section 12
2.7	Consider the organisational structure and capability necessary to deliver the AMP;	Section 5
2.8	Consider the organisational and contractor competencies and any training requirements;	Section 5
2.9	Consider the systems, integration and information management necessary to deliver the plans;	Section 9
2.10	To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs;	Section 8
2.11	Promote continual improvements to asset management practices.	Section 5

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
3	**Contents of the AMP:**	
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Section 1
3.2	Details of the background and objectives of the EDB's asset management and planning processes;	Section 5
3.3	A purpose statement	Section 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;	Section 1
3.5	The date that it was approved by the directors;	Section 1
3.6	A description of stakeholder interests (owners, consumers etc)	Section 4
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including governance, executive and field operations -	Section 5
3.8	All significant assumptions:	Section 3
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;	Section 3
3.10	An overview of asset management strategy and delivery;	Section 5 and 12
3.11	An overview of systems and information management data;	Section 5 and 9
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;	Section 9
3.13.	A description of the processes used within the EDB for-	
3.13.1	Managing routine asset inspections and network maintenance;	Section 8
3.13.2	Planning and implementing network development projects; and	Sections 7 and 12
3.13.3	Measuring network performance;	Section 12x
3.14	An overview of asset management documentation, controls and review processes.	Section 5 and 12
3.15	An overview of communication and participation processes;	Section 4
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Schedules 11(a)&(b)
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	Compliant
	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-	Section 7
4.1.1	The region(s) covered;	Section 7
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 7
4.1.3	Description of the load characteristics for different parts of the network;	Section 7
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 7

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
4.2	A description of the network configuration, including-	Section 7
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;	Section 7
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;	Section 7
4.2.3	A description of the distribution system, including the extent to which it is underground;	Section 6
4.2.4	A brief description of the network's distribution substation arrangements;	Section 7
4.2.5	A description of the low voltage network including the extent to which it is underground; and	Section 8
4.2.6	An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Section 8
4.3	If sub-networks exist, the network configuration information referred to in sub clause 4.2 above must be disclosed for each sub-network.	N/A
4.4	The AMP must describe the network assets by providing the following information for each asset category-	Section 8
4.4.1	Voltage levels;	Section 8
4.4.2	Description and quantity of assets;	Section 8
4.4.3	Age profiles; and	Section 8
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.	Section 8
4.5.	The asset categories discussed in clause 4.4 should include at least the following-	Section 8
4.5.1.	The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	Section 8
4.5.2.	Assets owned by the EDB but installed at bulk electricity supply points owned by others;	NA
4.5.3.	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 8
4.5.4.	Other generation plant owned by the EDB.	NA
	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.	Section 12
6	Performance indicators for which targets have been defined in clause 5 above must include SAIDI values and SAIFI values for the next 5 disclosure years.	Section 12
7	Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1	Customer oriented indicators that preferably differentiate between different customer types;	Section 4

	CONTENTS OF THE AMP CLAUSE	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.	
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 customer 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.	Section 7
9	Targets should be compared to historic values where available to provide context and scale to the reader.	Section 7
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	Sections 7, 8
	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;	Section 6
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;	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;	Section 5, 6
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	Section 8
11.4.1	The categories of assets and designs that are standardised;	Section 5, 8
11.4.2	The approach used to identify standard designs.	Section 5, 8
11.5	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	Section 5
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.	Section 6
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.	Section 6
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;	Section 7
11.8.1	Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 6
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;	Section 7
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 7
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.	Section 7
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-	Section 7

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
11.9.1	The reasons for choosing a selected option for projects where decisions have been made;	Section 7
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;	
11.9.3	Consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	Section 8
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-	Section 5
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 8
11.10.2	A summary description of the programmes and projects planned for the following four years (where known); and	Section 7
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	Section 7
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.	Section 3
11.12	A description of the EDB's policies on non-network solutions, including-	Section 9
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	Section 6, 9
11.12.2	The potential for non-network solutions to address network problems or constraints.	Section 8, 9
	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;	Section 8
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-	Section 8
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;	Section 8
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Section 8
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period.	Section 8
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-	Section 8
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;	Section 8
12.3.2	A description of innovations made that have deferred asset replacement;	Section 8
12.3.3	A description of the projects currently underway or planned for the next 12 months;	Section 8
12.3.4	A summary of the projects planned for the following four years (where known); and	Section 8
12.3.5	An overview of other work being considered for the remainder of the AMP planning period.	Section 7

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
12.4	The asset categories discussed in subclasses 12.2 and 12.3 above should include at least the categories in sub clause 4.5 above.	Section 8
12.5	Identification of the approach used for developing capital expenditure projects for lifecycle asset management, including an explanation of	Section 8
12.5.1	Approach used to inform capital expenditure projections for lifecycle asset management	Section 8
12.5.2	The rationale for using the approach for each asset category	Section 8
12.6	Identification of vegetation management related maintenance, including an explanation of the approach and assumptions used to inform vegetation management related maintenance	Section 8
12.7	Consideration of non-network solutions to inform capital and operational expenditure projections for lifecycle asset management, including an explanation of the approach and assumptions used to inform these expenditure projections	Section 8
	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;	Section 9
13.2	Development, maintenance and renewal policies that cover them;	Section 5
13.3	A description of material capital expenditure projects (where known) planned for the next five years;	Section 7
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	Section 8
	Risk management:	
14	AMPs must provide details of risk policies, assessment, and mitigation, including–	
14.1	Methods, details and conclusions of risk analysis;	Section 3, 10
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;	Section 3, 10
14.3	A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2;	Section 10
14.4	Details of emergency response and contingency plans.	Section 10
	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;	Section 11, 12
15.2	An evaluation and comparison of actual service level performance against targeted performance;	Section 12
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.	Section 5
15.4	An analysis of gaps identified in subclasses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 5

	CONTENTS OF THE AMP CLAUSE	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;	Section 12
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section 12
	Narrative:	
17	Requirements to provide qualitative information in narrative form: AMPs must include the following qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
17.1	Notice of planned and unplanned interruption. A description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any plans for changing the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	Section 4
17.2	**Voltage quality.** A description of the EDB's practices for monitoring voltage including:	Section 6
17.2.1	The EDB's practices for monitoring voltage quality on its low voltage network	Section 3, 6
17.2.2	Work the EDB is doing on its low voltage network to address any known non-compliance with applicable voltage requirements of the Electricity (Safety) Regulations 2010	Section 5
17.2.3	How the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder	Section 4
17.2.4	How the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network	Section 4, 6
17.3	**Customer service practices.** A description of the EDB's customer services practices including:	Section 4
17.3.1	The EDB's customer engagement protocols and customer service measures including customer satisfaction with the EBD's supply of electricity distribution services	Section 4
17.3.2	The EDB's approach to planning and managing customer complaint resolution	Section 4
17.4	Practices for connecting new consumers and altering existing connections	Section 4
17.4.1	A description of the EDB's practices for connecting consumers, including the EDB's approach to planning and management of:	Section 4
17.4.1(a)	Connecting new consumers, and overcoming commonly encountered issues	Section 4
17.4.1(b)	Alterations to existing connections	Section 4
17.4.2	How the EDB is seeking to minimse the cost to consumers of new or altered connections	Section 4
17..4.3	The EDB's approach to planning and managing communication with consumers about new or altered connections	Section 4
17.4.4	Commonly encountered delays and potential timeframes for different connections	Section 4
17.5	A description of the following:	Section 4
17.5.1	How the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including:	Section 6
17.5.1(a)	How the EDB measures the scale and impact of new demand, generation, or storage capacity	Section 6
17.5.1(b)	How the EDB takes the timing and uncertainty of new demand generation, or storage capacity into account	Section 6
17.5.1(c)	How the EDB takes other factors into account, eg, the network location	Section 6

	CONTENTS OF THE AMP CLAUSE	AMP SECTION
17.5.2	How the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity	Section 6, 7
17.6	**Innovation practices.** A description of the following:	Section 9
17.6.1	Any innovation practices the EDB has planned or undertaken since the last AMP was publicly disclosed, including case studies and trials	Section 9
17.6.2	The EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers	Section 9
17.6.3	How the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides weather to commence, commercially adopt or discontinue these practices	Section 12
17.6.4	How the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions	Section 12
17.6.5	The types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	Section 9
17.7	For the purpose of the information required under clauses 17.6.1-17.6.4 above, AMPs do not need to include commercially sensitive or confidential information.	NA

Appendix C: Region schematic diagrams

This appendix contains the schematic Single Line Diagrams for each region.

Albury region network configuration

The Albury GXP is fed of the TIM–TKA 110 kV line and has a single 110/11 kV transformer connected to an 11 kV switchboard. The transformer was upgraded in 2017 from 6 to 20 MVA. These are Transpower assets.

The Albury GXP can connect the Transpower mobile substation (110 kV to 11/22/33 kV) to allow maintenance at the Albury GXP and Albury zone substation.

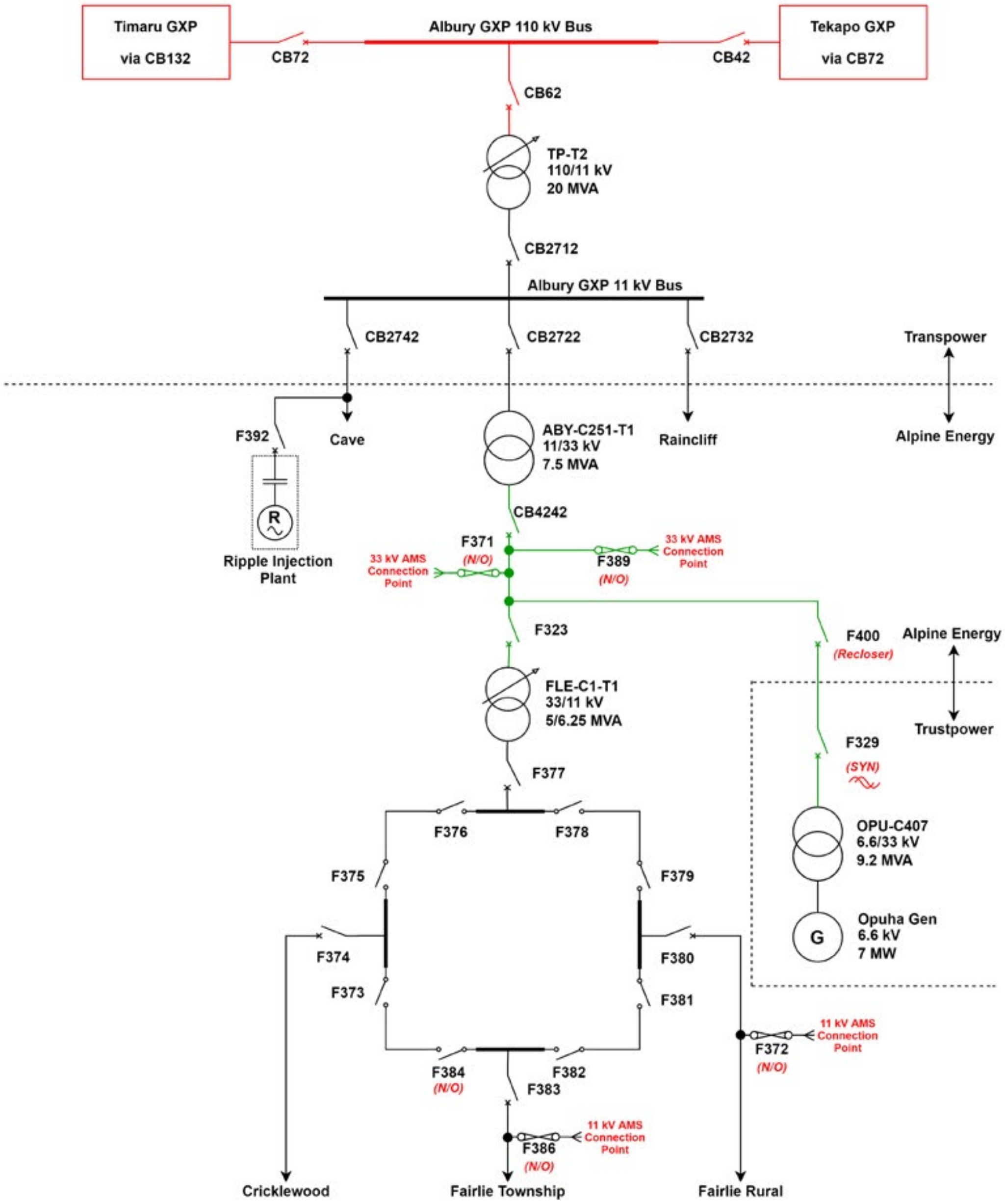
We take supply from three feeder CBs, two of which supply the 11 kV distributions feeders around Albury. The remaining circuit breaker feed into an 11/33 kV, 7.5 MVA step-up transformer for the supply to Fairlie, using a single 33 kV sub-transmission feeder (overhead). This same 33 kV feeder connects to the Opuha power station[1] (7 MW) beyond Fairlie.

There is an 11 kV ripple injection plant located at the Albury zone substation.

The Fairlie zone station has a 5/6.25 MVA transformer feeding three 11 kV distribution feeders for the Fairlie township and surround rural area. There are connections available for our mobile substation (33/11 kV, 9 MVA) and mobile generator (11 kV, 1.5 MVA).

[1] www.opuhawater.co.nz

Albury Region Network Overview



Bells Pond region network configuration

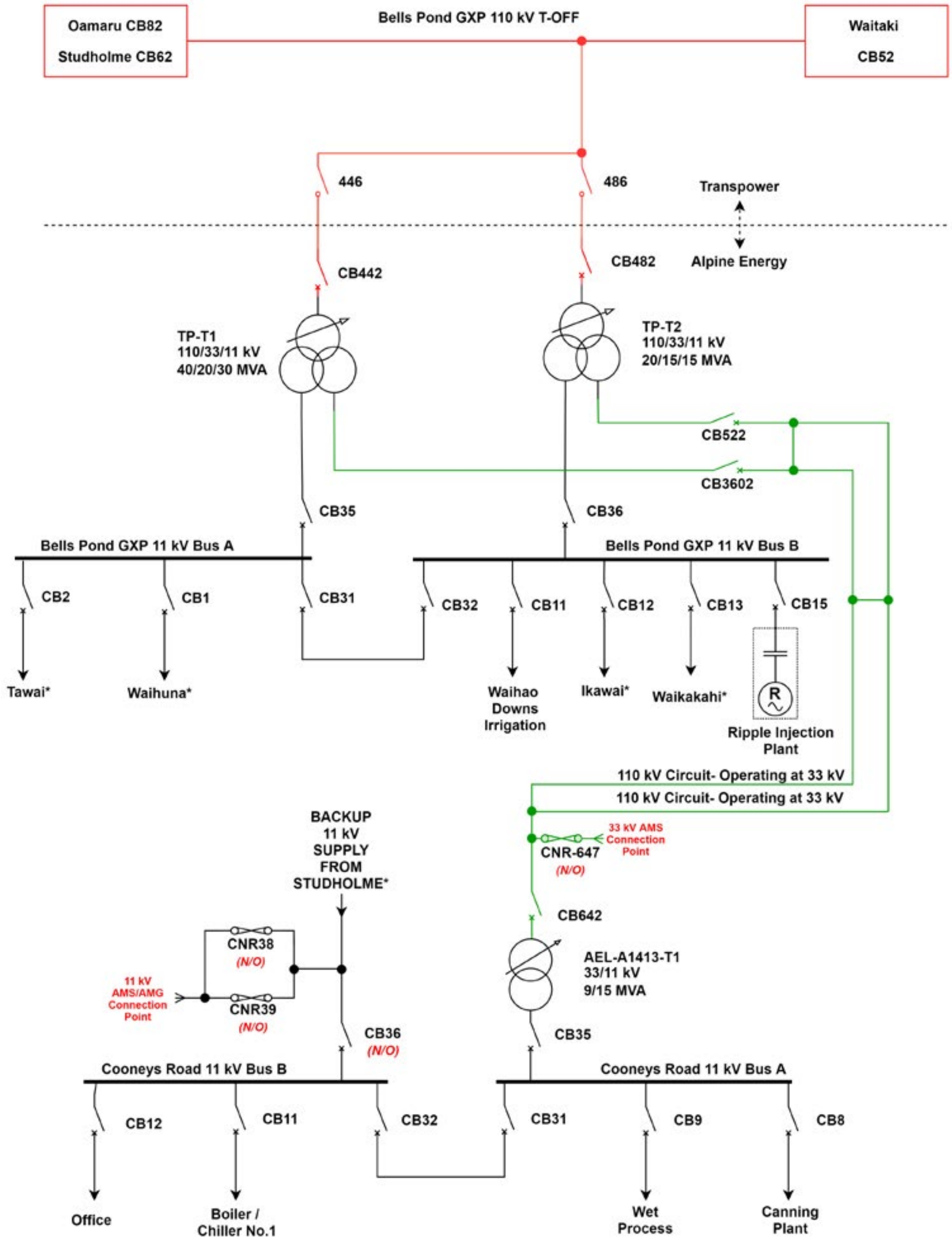
Bells Pond GXP is a single tee of the STU–OAM–WTK2 110 kV Transpower transmission circuit. The GXP is essentially a 110 kV metering point with us owning and operating the 110/33/11 kV zone substation. The Bells Pond Zone Substation has two 110/33/11 kV power transformers, 20/15/15 MVA and 40/20/30 MVA each feeding into two 11 kV switchboards with a bus coupler. There are five 11 kV distribution feeders supplying the area around Bells Pond, with one dedicated to the Waihao Downs irrigation pump station.

There is an 11 kV ripple injection plant located at the Bells Pond Zone Substation.

A sub-transmission line (dual paralleled circuit on a single pole line) constructed at 110 kV but operated at 33 kV supplies the Cooneys Road zone substation. This zone substation is located immediately adjacent to the Oceania Dairy Limited. The 11 kV from the power transformers at Bells Pond supply the local rural feeders.

The Cooneys Road zone substation has a single 33/11 kV, 9/15 MVA transformer feeding a single 11 kV switchboard. Four 11 kV feeders are dedicated to Oceania Dairy Limited, with one distribution feeder connected to an adjacent feeder from the Studholme zone substation (to provide back supply up to 1 MW).

Bells Pond Region Network Overview



* Marked feeders interconnect with STU for backup supply

Studholme (Waimate) region network configuration

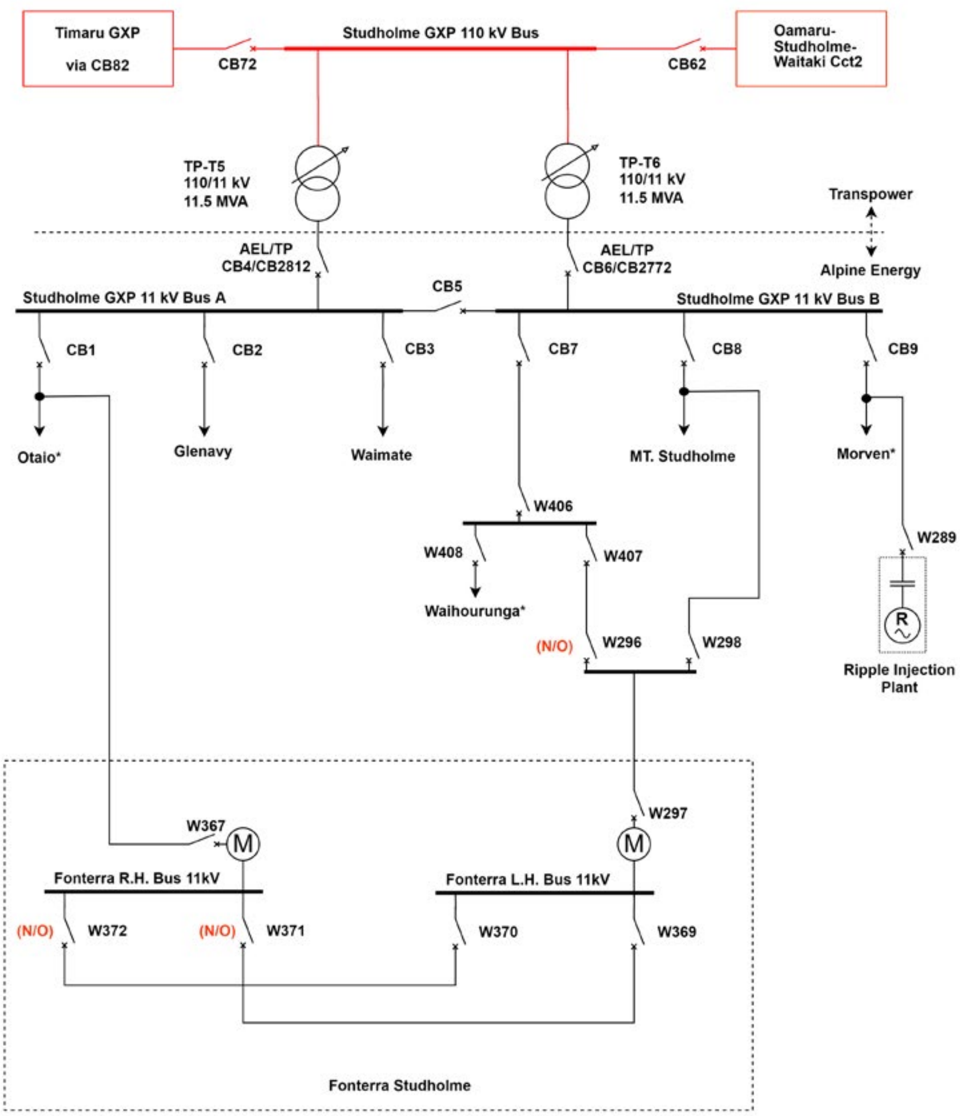
The Studholme GXP is supplied from the 110 kV transmission from Timaru and from Waitaki. The 110 kV system is permanently split on a manually operated switch (STU DS66). This means the Studholme GXP is supplied from TImaru on N security. There are two 110/11 kV, 10/12/12 MVA transformers banks (single phase units) owned and operated by Transpower.

We take supply from Transpower at 11 kV. The 11 kV indoor switchgear has two incoming supplies, and six feeders supplying the nearby Fonterra Studholme dairy factory, the Waimate township, and the surrounding rural area. The 11 kV switchboard and building is located on Transpower land.

The Fonterra Studholme dairy factory is supplied from three 11 kV distributions feeders (not dedicated) through a switching station (adjacent to the factory) comprising ring main units.

The ripple injection plant is connected to the Morven 11 kV distribution feeder.

Studholme Region



* Marked feeders interconnect with BPD and CNR for backup supply

(M) - Metering Point

Tekapō region network configuration

Transpower operates an 11 kV switchboard that connects to the Genesis Energy Tekapō power station. There are two step-up transformers; one 110/11 kV, 35 MVA transformer connected to the 110 kV Tekapō Albury Timaru transmission line and one 33/11 kV, 10 MVA transformer from which we take supply.

Genesis Energy can make its generator (28 MW) available to supply our Tekapō load when the Albury Tekapō 110 kV circuit is out of service, and the Tekapō and Albury load when the Albury Timaru 110 kV circuit is out of service.

Black start of the Tekapō generation and supplying the Tekapō load was successfully tested in November 2017 and used successfully in 2019 and 2020.

The Tekapō GXP can connect the Transpower mobile substation (110 kV to 11/22/33 kV) to allow maintenance at the Tekapō GXP. From the Tekapō GXP, we have a single 33 kV sub-transmission circuit to our 33/11 kV Tekapō zone substation (9/15 MVA transformer). From Tekapō zone substation we have a 33 kV sub-transmission line to Glentanner and Unwin Hut substations.

At Glentanner there are 33/0.4 kV distribution transformers supplying consumers.

Unwin Hut is a small 33/11 kV zone substation which supplies the Mt Cook Village via a 1.5 MVA transformer and two 11 kV underground distribution feeders.

A 33 kV ripple plant is located at the Tekapō zone substation and connected via a tap-off connection on to the 33 kV sub-transmission circuit.

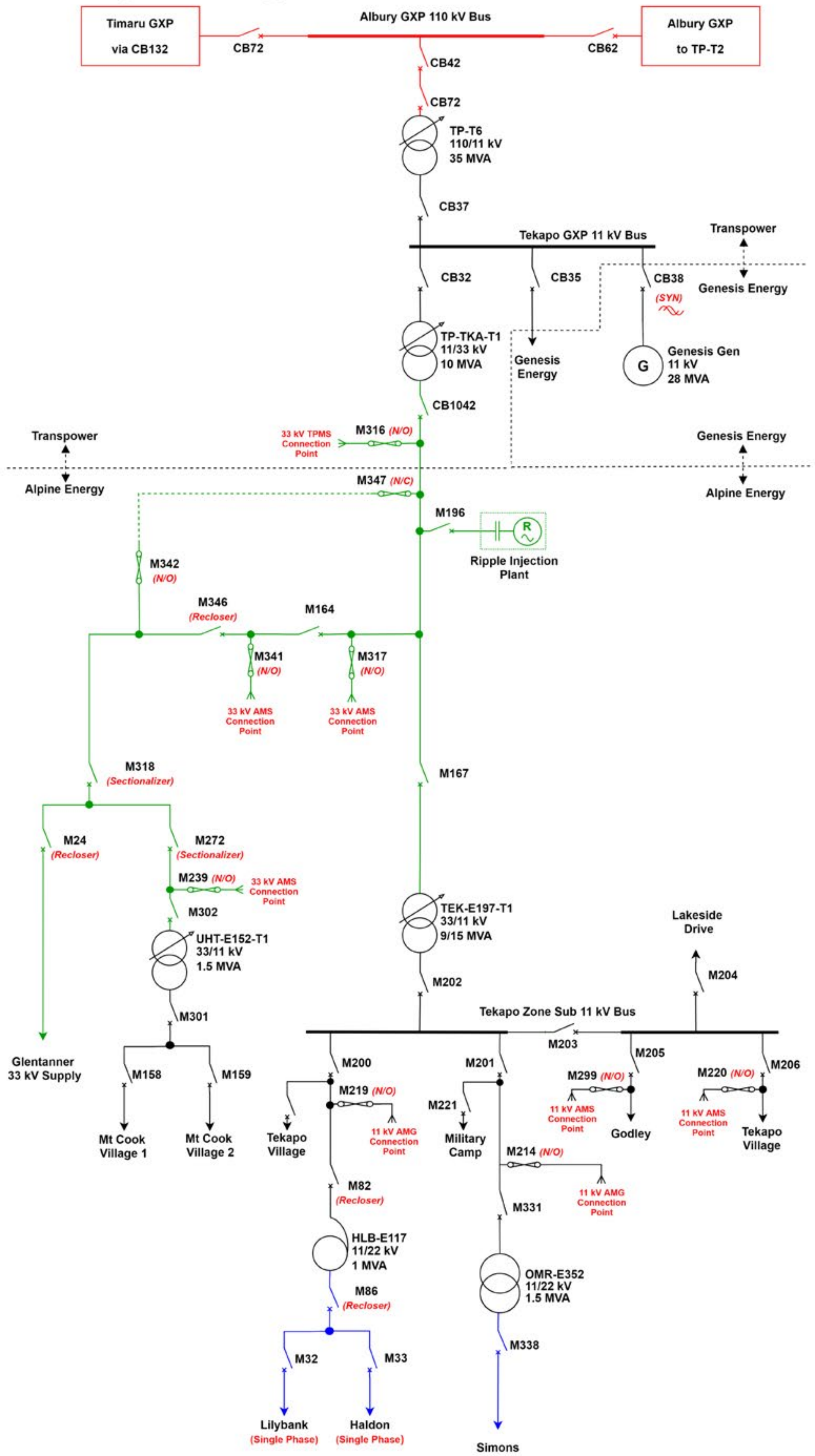
Connections for the mobile substation and standby/emergency diesel generation are available at the Tekapō zone substation.

The Tekapō zone substation supplies the Tekapō township and surrounding rural areas with five 11 kV feeders.

Old Man Range (OMR – 1.5 MVA autotransformer) and Haldon–Lilybank (HLB – 1 MVA Auto transformer) are two zone substations fed off Tekapō which act as step-up transformers 22/11 kV into the remote Haldon, Lilybank, and Simons Pass areas. The 22 kV distribution past the Haldon Lilybank zone substation is single phase.

There is a 33 kV Alpine mobile substation connection at Unwin Hut zone substation and an 11 kV Alpine Mobile Generator connection at Haldon Lilybank.

Tekapo Region Network Overview



Temuka Region network configuration

The Temuka GXP is supplied by two 110 kV transmission lines from the Transpower Timaru substation.

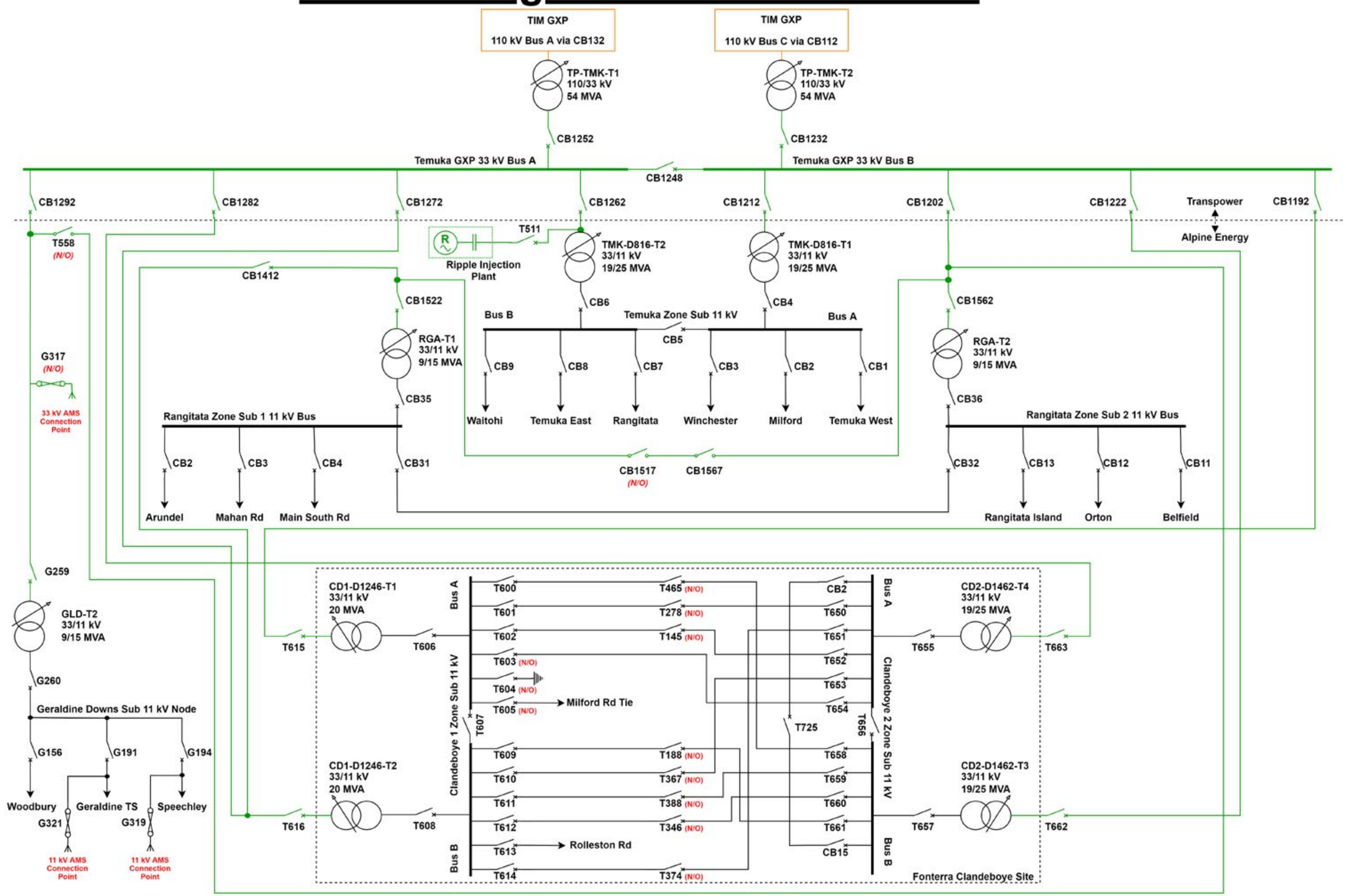
At the GXP, there are two 110/33 kV, 54 MVA power transformers which supply into a double switchboard. These transformers have a Special Protection Scheme (SPS) applied to mitigate against a total supply loss in the unlikely event of a transformer, or 110 kV line trip, while the load is more than 54 MVA. This will provide some security while the GXP constraint is being addressed.

There are eight feeders from the 33 kV bus that supplies our network as follows:

- Four sub-transmission feeders to Fonterra's Clandeboye dairy factory
  - Two double circuit lines and two cable circuits running through different routes for security
  - They supply two 33/11 kV zone substations at the factory site
  - Clandeboye 1 and Clandeboye 2 zone substations consists of two 20 MVA and two 19/25 MVA transformers, respectively
  - Clandeboye 1 and Clandeboye 2 zone substations consists of eleven and nine feeders, respectively, interconnected together for SoS
  - 33/11 kV Rangitata 1 zone substation is supplied from a tap off one of the overhead lines
- Two feeders supply our local 33/11 kV Temuka zone substation
  - Consists of two 19/25 MVA transformers with six 11 kV distribution feeders
- One sub-transmission feeder feeds the 33/11 kV Rangitata 2 zone substation
  - Consists of a two 9/15 MVA transformer with six 11 kV distribution feeders (11 kV bus tie is normally closed)
- One sub-transmission feeder feeds the 33/11 kV Geraldine zone substation
  - Consists of a single 7 MVA transformer with three 11 kV distribution feeders

A 33 kV ripple injection plant is connected to the 33 kV sub-transmission feeders that supply our Temuka zone substation.

Temuka Region Network Overview



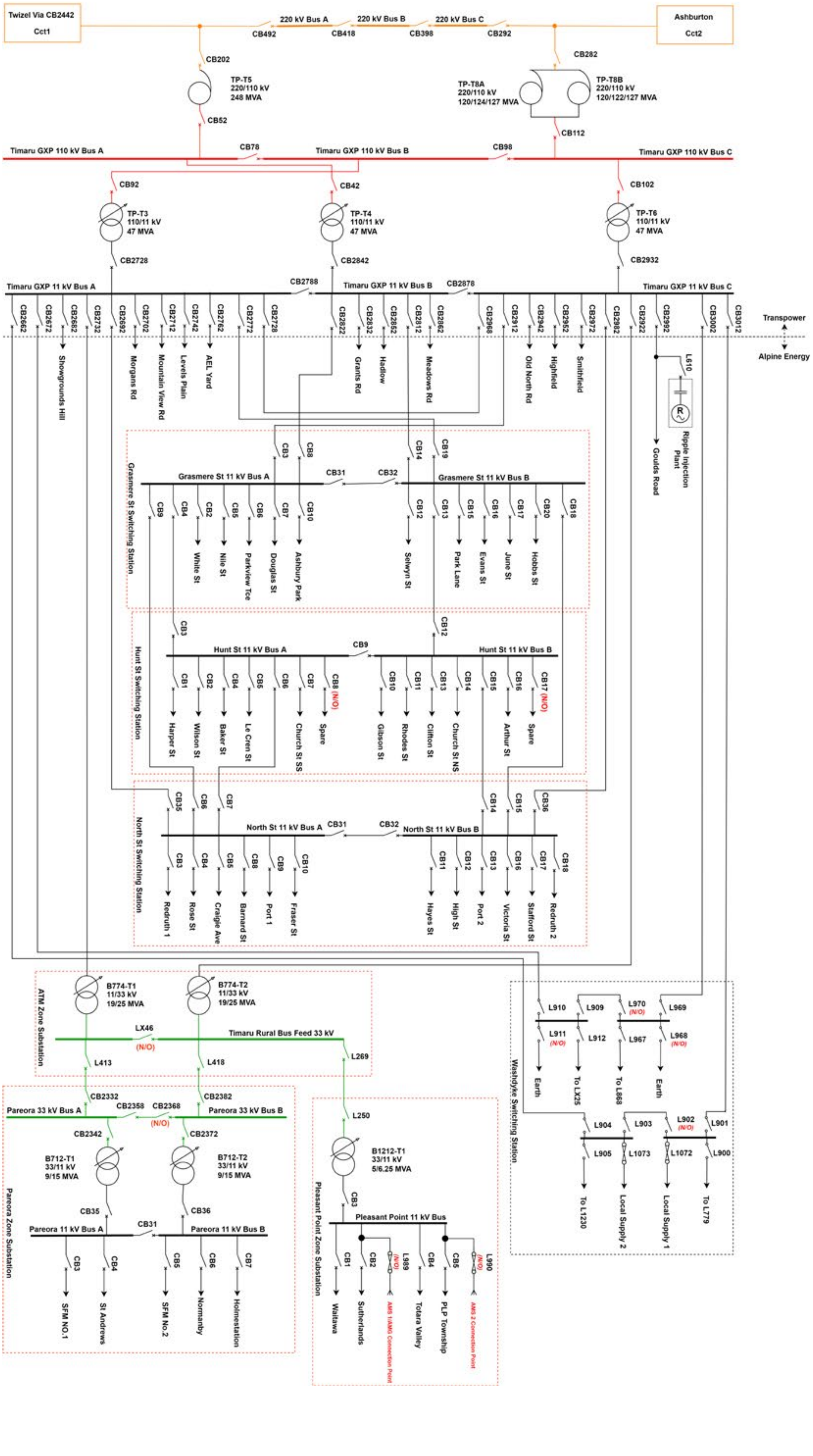
Timaru region network configuration

The Timaru GXP is our largest supply point connecting two 220/110 kV interconnectors to provide a 110 kV bus, which acts as a transmission hub (owned and operated by Transpower) for Albury, Tekapō, Temuka, and Bells Pond/Studholme. The 110 kV is stepped down through three transformer banks to supply the Timaru GXP 11 kV switchboard (owned by Transpower). The Timaru 110/11 kV 47 MVA transformers are operated with two in service and one on hot standby.

There are 24 feeders from the 11 kV switchboard which are split across three buses as follows:

- The ripple injection plant is connected to the 11 kV switchboard (bus C).
- Twelve of the feeders supply the western residential areas, the northern residential and industrial areas of Washdyke, and the meat-works at Smithfield.
- Two 11 kV feeders connect to two 11/33 kV step-up transformers at Timaru, supplying one 33 kV sub-transmission feeder to Pleasant Point zone substation and two 33 kV sub-transmission feeders to the Pareora zone substation.
  - Pareora zone substation has five 11 kV distribution feeders supplying meat works and rural load at the south of Timaru.
  - Pleasant Point zone substation has four 11 kV distribution feeders supplying Pleasant Point township and outlying rural.
- There are four 11 kV sub-transmission feeders to Grasmere switching station, which then split into a double circuit ring configuration to Hunt Street and North Street switch stations.
  - Grasmere switching station has 10 11 kV distribution feeders.
  - Two sub-transmission feeders to Hunt Street switching station and North Street switching station respectively.
- The Hunt Street switching station has 10 11 kV distribution feeders.
  - Two sub-transmission feeders to North Street switching station.
- Two 11 kV sub-transmission feeders connect directly to North Street switching station (cables rated at 33 kV).
  - The North Street switching station has twelve 11 kV distribution feeders. While North Street is presently a switching station, there is space to fit 33/11 kV transformers when load requires the substation to be converted to a zone substation.
- There are four 11 kV sub-transmission feeders supplying the Washdyke switching station (cables rated at 33 kV). There is space to convert Washdyke switching station to a 33/11 kV zone substation in the future.
  - Washdyke switching station (four RMUs), has four 11 kV distribution feeders supplying the Washdyke/Seadown commercial and rural area north of Timaru.

Timaru Region Network Overview



Twizel region network configuration

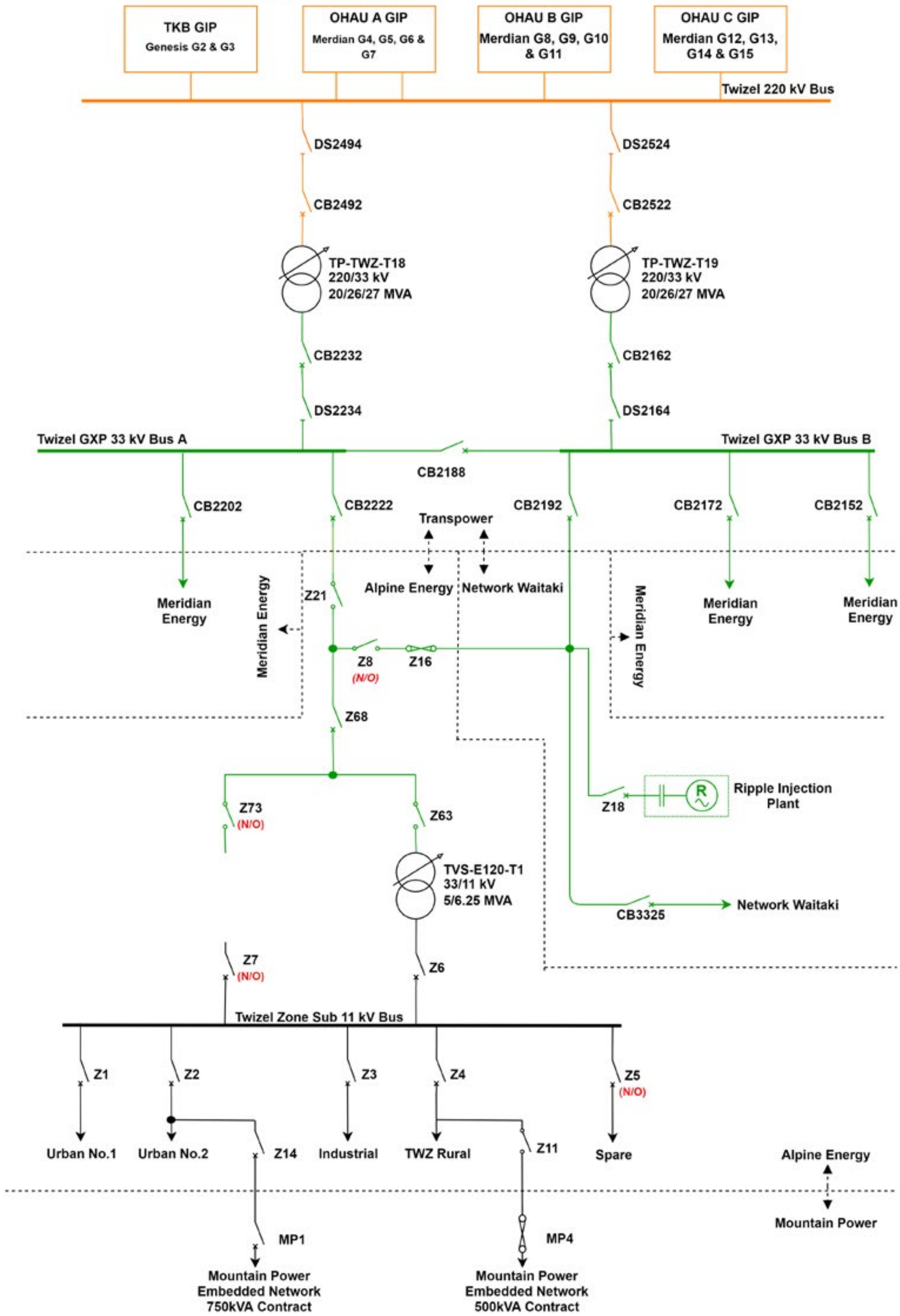
The Twizel GXP is supplied off the 220 kV Twizel bus and supplies us, Network Waitaki and Meridian Energy at 33 kV. The 220/33 kV step down transformers (2 off) are owned and operated by Transpower and feed in to a double 33 kV bus. We take supply from the 33 kV bus A. There is space in the switch board building to add another circuit breaker to allow us to take a second supply from the GXP (to improve SoS).

There is a ripple injection plant at the Twizel GXP, but is dedicated to Network Waitaki, due to the 33 kV switching configuration.

A single 33 kV sub-transmission line supplies our 33/11 kV Twizel township zone substation. At the substation, we have one 33/11 kV 5/6/5 MVA power transformer.

There is an indoor 11 kV switchboard with two distribution feeders supplying the Twizel township, two distribution feeders supplying the surrounding rural areas and one spare circuit breaker. We have an embedded network in the Twizel township supplying new developments in this area. The embedded network is supplied from two connection points at Manuka Terrace and Mackenzie Park.

Twizel Region Network Overview



Schedule 11a. Report on forecast capital expenditure

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

7 8	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	CY+6 31 Mar 29	CY+7 31 Mar 30	CY+8 31 Mar 31	CY+9 31 Mar 32	CY+10 31 Mar 33
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	6,340	5,500	5,165	5,289	5,934	6,053	6,174	6,297	6,423	6,552	6,683
11	System growth	3,638	4,555	5,692	5,871	3,140	7,825	6,185	6,996	3,749	2,394	2,928
12	Asset replacement and renewal	13,279	17,282	14,421	16,808	21,039	18,742	16,142	16,969	16,899	19,441	18,007
13	Asset relocations	130	400	465	476	486	495	505	515	526	536	547
14	Reliability, safety and environment:											
15	Quality of supply	-	150	155	793	162	165	168	172	175	179	182
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	665	1,635	1,999	1,312	1,338	1,365	1,347	1,259	1,238	1,263	1,288
18	**Total reliability, safety and environment**	**665**	**1,785**	**2,154**	**2,105**	**1,500**	**1,530**	**1,515**	**1,431**	**1,413**	**1,442**	**1,470**
19	**Expenditure on network assets**	**24,052**	**29,522**	**27,897**	**30,549**	**32,099**	**34,645**	**30,521**	**32,208**	**29,010**	**30,365**	**29,635**
20	Expenditure on non-network assets	984	4,776	4,642	4,265	4,324	2,059	1,857	2,259	2,394	2,301	2,418
21	**Expenditure on assets**	**25,036**	**34,298**	**32,539**	**34,814**	**36,423**	**36,704**	**32,378**	**34,467**	**31,404**	**32,666**	**32,053**
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	7,200	5,000	5,648	4,760	5,395	5,503	5,613	5,726	5,840	5,957	6,076
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	**17,836**	**29,298**	**26,891**	**30,054**	**31,028**	**31,201**	**26,765**	**28,741**	**25,564**	**26,709**	**25,977**
29	Assets commissioned	18,000	38,301	28,069	30,054	31,028	31,251	26,766	28,742	25,565	26,709	25,978
32		**$000 (in constant prices)**										
33	Consumer connection	4,400	5,500	5,000	5,000	5,500	5,500	5,500	5,500	5,500	5,500	5,500
34	System growth	2,870	4,555	5,510	5,550	2,910	7,110	5,510	6,110	3,210	2,010	2,410
35	Asset replacement and renewal	12,855	17,282	13,960	15,890	19,500	17,030	14,380	14,820	14,470	16,320	14,820
36	Asset relocations	1,400	400	450	450	450	450	450	450	450	450	450
37	Reliability, safety and environment:											
38	Quality of supply	-	150	150	750	150	150	150	150	150	150	150
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	980	1,635	1,935	1,240	1,240	1,240	1,200	1,100	1,060	1,060	1,060
41	**Total reliability, safety and environment**	**980**	**1,785**	**2,085**	**1,990**	**1,390**	**1,390**	**1,350**	**1,250**	**1,210**	**1,210**	**1,210**
42	**Expenditure on network assets**	**22,505**	**29,522**	**27,005**	**28,880**	**29,750**	**31,480**	**27,190**	**28,130**	**24,840**	**25,490**	**24,390**
43	Expenditure on non-network assets	2,777	4,776	4,493	4,032	4,008	1,871	1,260	1,560	1,560	1,560	1,560
44	**Expenditure on assets**	**25,282**	**34,298**	**31,498**	**32,912**	**33,758**	**33,351**	**28,450**	**29,690**	**26,400**	**27,050**	**25,950**

Schedule 11a. Report on forecast capital expenditure continued

46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	250	250	250	250	250	250	250	250	250	250
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
50	Cybersecurity (Commission only)	-	465	-	-	-	-	-	-	-	-	-
52 53	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**	**CY+6 31 Mar 29**	**CY+7 31 Mar 30**	**CY+8 31 Mar 31**	**CY+9 31 Mar 32**	**CY+10 31 Mar 33**
54	**Difference between nominal and constant price forecasts**	**$000**										
55	Consumer connection	1,940	-	165	289	434	553	674	797	923	1,052	1,183
56	System growth	768	-	182	321	230	715	675	886	539	384	518
57	Asset replacement and renewal	424	-	461	918	1,539	1,712	1,762	2,149	2,429	3,121	3,187
58	Asset relocations	(1,270)	-	15	26	36	45	55	65	76	86	97
59	Reliability, safety and environment:											
60	Quality of supply	-	-	5	43	12	15	18	22	25	29	32
61	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
62	Other reliability, safety and environment	(315)	-	64	72	98	125	147	159	178	203	228
63	**Total reliability, safety and environment**	**(315)**	**-**	**69**	**115**	**110**	**140**	**165**	**181**	**203**	**232**	**260**
64	**Expenditure on network assets**	**1,547**	**-**	**892**	**1,669**	**2,349**	**3,165**	**3,331**	**4,078**	**4,170**	**4,875**	**5,245**
65	Expenditure on non-network assets	(1,793)	-	149	233	316	188	597	699	834	741	858
66	**Expenditure on assets**	**(246)**	**-**	**1,041**	**1,902**	**2,665**	**3,353**	**3,928**	**4,777**	**5,004**	**5,616**	**6,103**

Schedule 11a. Report on forecast capital expenditure continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

72	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
73	**11a(ii): Consumer Connection**						
74	*Consumer types defined by EDB**	**$000 (in constant prices)**					
75	Low user charge	220	275	250	250	275	275
76	15	616	770	700	700	770	770
77	360	528	660	600	600	660	660
78	Assessed	1,012	1,265	1,150	1,150	1,265	1,265
79	TOU 400 V	2,024	2,530	2,300	2,300	2,530	2,530
80	**include additional rows if needed*						
81	**Consumer connection expenditure**	**4,400**	**5,500**	**5,000**	**5,000**	**5,500**	**5,500**
82	*less* Capital contributions funding consumer connection	3,600	5,000	4,500	4,500	5,000	5,000
83	**Consumer connection less capital contributions**	**800**	**500**	**500**	**500**	**500**	**500**
84	**11a(iii): System Growth**						
85	Subtransmission	-	285	550	550	150	450
86	Zone substations	-	3,700	3,000	3,000	500	4,400
87	Distribution and LV lines	450	-	-	-	-	-
88	Distribution and LV cables	2,420	540	1,960	2,000	2,260	2,260
89	Distribution substations and transformers	-	-	-	-	-	-
90	Distribution switchgear	-	-	-	-	-	-
91	Other network assets	-	30	-	-	-	-
92	System growth expenditure	**2,870**	**4,555**	**5,510**	**5,550**	**2,910**	**7,110**
93	less Capital contributions funding system growth	-	-	-	-	-	-
94	System growth less capital contributions	**2,870**	**4,555**	**5,510**	**5,550**	**2,910**	**7,110**
95							
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
99	Subtransmission	-	7,914	7,940	9,320	10,300	7,900
100	Zone substations	1,480	4,144	210	710	3,610	3,110
101	Distribution and LV lines	7,910	-	-	-	-	-
102	Distribution and LV cables	-	1,580	1,460	1,260	860	960
103	Distribution substations and transformers	1,490	2,874	2,970	3,230	3,400	3,750
104	Distribution switchgear	1,110	390	940	940	940	920
105	Other network assets	865	380	440	430	390	390
106	**Asset replacement and renewal expenditure**	**12,855**	**17,282**	**13,960**	**15,890**	**19,500**	**17,030**
107	*less* Capital contributions funding asset replacement and renewal	200	-	968	-	-	-
108	**Asset replacement and renewal less capital contributions**	**12,655**	**17,282**	**12,992**	**15,890**	**19,500**	**17,030**

Schedule 11a. Report on forecast capital expenditure continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

110		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
111	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
112	**11a(v): Asset Relocations**	**$000 (in constant prices)**					
113	*Project or programme**						
114	Overhead to Underground conversions	1,400	250	250	250	250	250
115	B1508 Transformer replacement (High Risk)	-	150	-	-	-	-
116	Relocate transformers located at hazardous areas.	-	-	200	200	200	200
117		-	-	-	-	-	-
118		-	-	-	-	-	-
119	**include additional rows if needed*						
120	All other project or programmes - asset relocations	-	-	-	-	-	-
121	**Asset relocations expenditure**	**1,400**	**400**	**450**	**450**	**450**	**450**
122	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
123	**Asset relocations less capital contributions**	**1,400**	**400**	**450**	**450**	**450**	**450**
127	**11a(vi): Quality of Supply**						
128	*Project or programme**	**$000 (in constant prices)**					
129	Voltage regulator for Load and Voltage Control	-	150	150	150	150	150
130	New Timaru 33kV ripple plant.	-	-	-	600	-	-
131		-	-	-	-	-	-
132		-	-	-	-	-	-
133		-	-	-	-	-	-
134	**include additional rows if needed*						
135	All other projects or programmes - quality of supply	-	-	-	-	-	-
136	**Quality of supply expenditure**	**-**	**150**	**150**	**750**	**150**	**150**
137	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
138	**Quality of supply less capital contributions**	**-**	**150**	**150**	**750**	**150**	**150**
142	**11a(vii): Legislative and Regulatory**						
143	*Project or programme**	**$000 (in constant prices)**					
144	N/A	-	-	-	-	-	-
145		-	-	-	-	-	-
146		-	-	-	-	-	-
147		-	-	-	-	-	-
148		-	-	-	-	-	-
149	**include additional rows if needed*						
150	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
151	**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
153	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Schedule 11a. Report on forecast capital expenditure continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
154	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
155							
156	**11a(viii): Other Reliability, Safety and Environment**						
157	*Project or programme**	**$000 (in constant prices)**					
158	SCADA and Comms	410	465	195	90	90	90
159	Softwood pole replacement	160	200	200	200	200	200
160	Reclosers, automation & RMUs	260	450	460	190	190	330
161	AMG Circuit Breaker	150	-	150	-	-	-
160	Lucy Box Replacements	-	521	480	550	550	410
161	Substation Security Video Monitoring	-	-	240	-	-	-
162	Asbestos	-	-	210	210	210	210
163	**include additional rows if needed*						
164	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
165	**Other reliability, safety and environment expenditure**	**980**	**1,636**	**1,935**	**1,240**	**1,240**	**1,240**
166	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
167	**Other reliability, safety and environment less capital contributions**	**980**	**1,636**	**1,935**	**1,240**	**1,240**	**1,240**

Schedule 11a. Report on forecast capital expenditure continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

169 170	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
171	**11a(ix): Non-Network Assets**						
172	**Routine expenditure**						
173	*Project or programme**	**$000 (in constant prices)**					
174	Automation & remote control of network	-	100	100	100	200	200
175	Site Security	-	60	60	60	60	60
176	ADMS (Non-Network CAPEX)	-	200	200	2,000	2,000	200
176	Lidar	-	-	500	-	250	250
175	Future State ERP	-	250	1,000	200	200	200
176	Future State Architecture	-	250	500	100	100	100
177	Data Strategy Implementation	1,077	250	500	100	100	100
177	Value Chain Redesign	-	250	250	250	150	150
178	Vehicles	350	-	-	-	-	-
	Digital	-	1,570	1,087	1,061	809	566
	Other	350	446	96	161	139	45
179	**include additional rows if needed*						
180	All other projects or programmes - routine expenditure	-	-	-	-	-	-
181	**Routine expenditure**	**1,777**	**3,376**	**4,293**	**4,032**	**4,008**	**1,871**
182	**Atypical expenditure**						
183	*Project or programme**						
184	Transformer load visibility	-	200	-	-	-	-
185	Enterprise Content Management	-	200	200	-	-	-
186	Property	1,000	1,000	-	-	-	-
187	Digital	-	465	-	-	-	-
188		-	-	-	-	-	-
189	**include additional rows if needed*						
190	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
191	**Atypical expenditure**	**1,000**	**1,865**	**200**	**-**	**-**	**-**
193	**Expenditure on non-network assets**	**2,777**	**5,241**	**4,493**	**4,032**	**4,008**	**1,871**

Schedule 11b. Report on forecast operational expenditure

7 8	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	CY+6 31 Mar 29	CY+7 31 Mar 30	CY+8 31 Mar 31	CY+9 31 Mar 32	CY+10 31 Mar 33
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,104	2,100	2,169	2,221	2,266	2,311	2,357	2,404	2,453	2,502	2,552
11	Vegetation management	721	1,050	1,085	1,375	1,403	1,431	1,459	1,488	1,518	1,549	1,580
12	Routine and corrective maintenance and inspection	3,221	3,400	3,512	3,596	3,668	3,742	3,704	3,778	3,737	3,812	3,888
13	Asset replacement and renewal	165	342	353	362	369	376	384	392	399	407	416
14	**Network Opex**	**6,211**	**6,892**	**7,119**	**7,554**	**7,706**	**7,860**	**7,904**	**8,062**	**8,107**	**8,270**	**8,436**
15	System operations and network support	8,853	9,691	10,720	10,777	10,978	11,229	11,383	11,607	11,872	12,143	12,343
16	Business support	9,417	10,969	13,747	13,575	13,693	13,958	14,182	14,436	14,746	15,080	15,319
17	**Non-network opex**	**18,270**	**20,660**	**24,467**	**24,352**	**24,671**	**25,187**	**25,565**	**26,043**	**26,618**	**27,223**	**27,662**
18	**Operational expenditure**	**24,481**	**27,552**	**31,586**	**31,906**	**32,377**	**33,047**	**33,469**	**34,105**	**34,725**	**35,493**	**36,098**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,045	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
23	Vegetation management	820	1,050	1,050	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
24	Routine and corrective maintenance and inspection	3,300	3,400	3,400	3,400	3,400	3,400	3,300	3,300	3,200	3,200	3,200
25	Asset replacement and renewal	290	342	342	342	342	342	342	342	342	342	342
26	**Network Opex**	**6,455**	**6,892**	**6,892**	**7,142**	**7,142**	**7,142**	**7,042**	**7,042**	**6,942**	**6,942**	**6,942**
27	System operations and network support	6,060	9,691	10,377	10,188	10,175	10,204	10,141	10,137	10,165	10,194	10,159
28	Business support	15,482	10,969	13,308	12,834	12,691	12,683	12,634	12,608	12,626	12,659	12,607
29	**Non-network opex**	**21,542**	**20,660**	**23,685**	**23,022**	**22,866**	**22,887**	**22,775**	**22,745**	**22,791**	**22,853**	**22,766**
30	**Operational expenditure**	**27,997**	**27,552**	**30,577**	**30,164**	**30,008**	**30,029**	**29,817**	**29,787**	**29,733**	**29,795**	**29,708**
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)*											
33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	277	346	346	346	346	346	346	346	346	346	346
37	Cybersecurity (Commission only)	88	100	310	320	320	320	320	320	320	320	320
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	59	-	69	121	166	211	257	304	353	402	452
44	Vegetation management	(99)	-	35	75	103	131	159	188	218	249	280
45	Routine and corrective maintenance and inspection	(79)	-	112	196	268	342	404	478	537	612	688
46	Asset replacement and renewal	(125)	-	11	20	27	34	42	50	57	65	74
47	**Network Opex**	**(244)**	**-**	**227**	**412**	**564**	**718**	**862**	**1,020**	**1,165**	**1,328**	**1,494**
48	System operations and network support	2,793	-	343	589	803	1,025	1,242	1,470	1,707	1,949	2,184
49	Business support	(6,065)	-	439	741	1,002	1,275	1,548	1,828	2,120	2,421	2,712
50	**Non-network opex**	**(3,272)**	**-**	**782**	**1,330**	**1,805**	**2,300**	**2,790**	**3,298**	**3,827**	**4,370**	**4,896**
51	**Operational expenditure**	**(3,516)**	**-**	**1,009**	**1,742**	**2,369**	**3,018**	**3,652**	**4,318**	**4,992**	**5,698**	**6,390**

Schedule 12a: Report on asset condition

7	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%	30.24%	34.38%	35.38%		3	0.50%
11	All	Overhead Line	Wood poles	No.	2.76%	13.71%	40.57%	17.21%	25.75%		3	3.00%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.06%	8.84%	24.45%	32.03%	34.63%		3	
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	0.29%	3.64%	96.07%		4	
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.	-	-	16.00%	32.00%	52.00%		3	
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.	5.26%	5.26%	26.32%	15.79%	47.37%		4	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	24.24%	12.12%	16.67%	-	46.97%		3	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	19.75%	12.35%	18.52%	1.23%	48.15%		3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.					100.00%		3	
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.	-	-	-	17.65%	82.35%		3	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	33.33%	-	66.67%		3	
35												

Schedule 12a: Report on asset condition continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

36	Asset condition at start of planning period (percentage of units by grade)											
37												
38	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
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	14.29%	14.29%	71.43%		3	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.72%	38.00%	20.22%	14.15%	26.91%		3	2.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	100.00%	-	-	-		3	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.27%	0.35%	0.58%	11.89%	86.91%		3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	2.16%	11.19%	28.99%	55.83%	1.83%		3	
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.	-	-	9.68%	37.10%	53.23%		3	
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	4.85%	-	14.55%	16.36%	64.24%		3	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	14.79%	5.65%	4.94%	22.70%	51.91%		3	5.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	30.61%	12.24%	-	-	57.14%		3	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.32%	15.49%	25.44%	12.39%	43.36%		3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.06%	30.34%	25.91%	25.05%	17.64%		3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.46%	16.12%	20.77%	34.61%	28.05%		3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	57.35%	42.65%		4	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	20.89%	13.40%	47.12%	14.98%	3.61%		3	2.00%
56	LV	LV Cable	LV UG Cable	km	1.19%	5.58%	19.41%	42.34%	31.49%		3	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km							N/A	
58	LV	Connections	OH/UG consumer service connections	No.							N/A	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2.01%	0.45%	11.19%	64.65%	21.70%		3	2.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2.38%	-	21.43%	47.62%	28.57%		3	5.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	22.22%	-	29.63%	48.15%		3	
62	All	Load Control	Centralised plant	Lot	1.19%	16.67%	10.71%	23.81%	47.62%		3	16.00%
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Schedule 12b: Report on forecast capacity

7	**12b(i): System Growth - Zone Substations**									
8	**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**
9	Albury (ABY)	3.71	-	N		-	-	-	No constraint within +5 years	Meets Alpine security standard
10	Old Man Range (OMR)	0.38	-	N		-	-	-	No constraint within +5 years	Balmoral substation decommissioned in 2019
11	Bells Pond (BPD)	13.22	20.00	N-1		66%	20.00	91%	Transpower	T1 installed FY18/19, T2 to be upgraded to provide N-1 security of supply
12	Clandeboye 1 (CD1)	13.89	20.00	N-1		69%	30.00	63%	Transformer	Upgrade transformers to restore N-1 security of supply
13	Clandeboye 2 (CD2)	19.79	25.00	N-1		79%	25.00	100%	No constraint within +5 years	Meets Alpine security standard due to sufficient 11 kV backup
14	Cooneys Road (CNR)	4.60	-	N	1.8/0.8/0.6	-	-	-	No constraint within +5 years	Meets Alpine security standard
15	Fairlie (FLE)	2.77	-	N		-	-	-	No constraint within +5 years	Meets Alpine security standard
16	Geraldine (GLD)	7.00	-	N		-	-	-	No constraint within +5 years	Transformer was replaced with a 15/9 MVA in 2021 due to end of life consideration
17	Haldon Lilybank (HLB)	0.68	-	N		-	-	-	No constraint within +5 years	Meets Alpine security standard
18	Pareora (PAR)	9.12	15.00	N-1		61%	15.00	66%	No constraint within +5 years	Meets Alpine security standard
19	Pleasant Point (PLP)	4.48	-	N		-	-	-	No constraint within +5 years	Meets Alpine security standard
20	Rangitata (RGA)	9.99	10.00	N-1		100%	10.00	108%	Subtransmission circuit	Line capacity constraint, sufficient 11 kV backup in place
21	Studholme (STU)	13.33	10.00	N-1		133%	40.00	44%	Transpower	Transpower replacing existing transformers with 2x 40MVA 110/11 Kv transformers in 2024
22	Tekapō Village (TEK)	4.25	-	N		-	15.00	65%	Transformer	Upgrade of transformer and the TEK substation option of constructing a twin substation to provide N-1 security of supply
23	Temuka (TMK)	12.58	25.00	N-1		50%	25.00	57%	No constraint within +5 years	Meets Alpine Security standard
24	Timaru 11/33 kV (TIM)	15.06	-	N		-	-	-	No constraint within +5 years	Meets Alpine Security standard
25	Twizel Village (TVS)	3.67	-	N		-	6.25	64%	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
26	Unwin Hut (UHT)	0.95	-	N		-	-	-	No constraint within +5 years	Meets Alpine security standard
27	Washdyke Zone Substation (WSS)		-			-	40	75%	No constraint within +5 years	Commissioning due in 2025
28						-				
29										

Schedule 12c: Report on forecast network demand

7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*	**Number of connections**					
9 10	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**
11	*Consumer types defined by EDB**						
12	Low Charge	13,247	13,560	13,660	13,760	13,860	13,960
13	Low Uncontrolled	58	58	59	60	61	62
14	015	17,010	16,967	17,092	17,217	17,342	17,467
15	015 Uncontrolled	75	74	74	74	74	74
	360	1,271	1,288	1,302	1,316	1,330	1,344
	360 Uncontrolled	29	29	29	29	29	29
	Assessed	1,702	1,733	1,748	1,763	1,778	1,793
	TOU 400V	135	135	135	135	135	135
	TOU 11kV	8	8	8	8	8	8
16	IND	12	12	12	12	12	12
17	**Connections total**	**33,547**	**33,864**	**34,119**	**34,374**	**34,629**	**34,884**
18	**include additional rows if needed*						
22	Distributed generation	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	416	426	449	472	495	518
24	Capacity of distributed generation installed in year (MVA)	3	29	4	4	4	4
25	**12c(ii) System Demand**						
27	**Maximum coincident system demand (MW)**						
28	GXP demand	138	148	149	149	150	151
29	*plus* Distributed generation output at HV and above	-	-	-	-	-	-
30	**Maximum coincident system demand**	**138**	**148**	**149**	**149**	**150**	**151**
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	**138**	**148**	**149**	**149**	**150**	**151**
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	829	877	882	885	888	891
35	*less* Electricity exports to GXPs	15	16	16	16	17	17
36	*plus* Electricity supplied from distributed generation	30	30	31	32	32	33
37	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38	**Electricity entering system for supply to ICPs**	**845**	**892**	**896**	**900**	**903**	**907**
39	*less* Total energy delivered to ICPs	809	843	847	850	854	857
40	**Losses**	**35**	**49**	**49**	**50**	**50**	**50**
41							
42	**Load factor**	**69%**	**69%**	**69%**	**69%**	**69%**	**69%**
43	**Loss ratio**	**5.5%**	**5.5%**	**5.5%**	**5.5%**	**5.5%**	**5.5%**

Schedule 12d: Report forecast interruptions and duration

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2023 – 31 March 2033

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
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)	55.0	55.0	55.0	55.0	55.0	55.0
12	Class C (unplanned interruptions on the network)	91.9	91.9	91.9	91.9	91.9	91.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	1.20	1.20	1.20	1.20	1.20	1.20

Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.5	Views vary on how widely the actual AM Policy has been circulated and understood, but most interviewees are aware of the general principles in the AM Policy.	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?	1.5	The AM Strategy is well stated, and links well with other documents such as the AM Policy and the AMP, but similar to Q3 it appears that verbal communication and reinforcement of the AM Strategy varies. Again, similar to Q3, there is a general awareness of the principles contained in the AM Strategy.	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?	2	The AM Strategy and the Asset Fleet Plans clearly recognise individual asset lifecycles, however it appears that the importance of asset condition data for driving lifecycle decisions is not well understood. There is great work in progress in this area.	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	The Asset Fleet Plans document individual lifecycle asset plans well enough, but the actual day-to-day work is messy and disjointed.	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).

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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?	1.5	There appears to be very little formal communication of key asset management themes that the wider business and contractors need to understand for training, recruitment, equipment purchasing etc. The current level of communication is either individual jobs or an annual budget, but not explanation of wider themes.	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?	2.5	Responsibilities for delivering work are very well documented, but views vary on how work delivery occurs in practice with views ranging from well enough to quite disjoint.	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	Financial forecasting and projections are done well. A People & Culture Strategy has been compiled, but detailed aspects such as skill mix forecasts and competency matrices are yet to occur.	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?	2	A wide range of contingency plans have been compiled, however updating those plans has lapsed as only one person was responsible for those plans and has left Alpine. One significant identified gap is the returning of fault information from NETcon.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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)?	2.5	Organisational structure and authorities are well documented, but views vary on how well workflow and communication occurs in practice.	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?	1.5	Whilst the need for cash is both well understand and well managed through a 10-year forecast, the concepts in the People & Culture Strategy have not yet cascaded down to detailed competency identification and recruitment plans.	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	Reporting formats and structures are well documented, suggesting that Alpine understand the need for good reporting. In practice, however, it seems that reporting is sparse and aggregated (i.e.. difficult to see the cause of variances).	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?	2.5	Alpine has documented a wide and appropriate range of both leading and lagging controls to ensure outsourced work meets standards, including such measures as NETcon only stocking Alpine-approved materials and all new contractors having their first three jobs inspected in detail. In practice, however, there are variances from material standards and work procedures.	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 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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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	Whilst there is a sound People & Culture Strategy, it has not yet cascaded down to the level of forecasting work volumes and skill mixes either within Alpine or to NETcon.	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?	1.5	Whilst competency and safety training is well done for network staff and contractors, similar systems are not yet in place for wider occupational classes.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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?	1.5	Alpine has structured training and competency matrices for network competencies, but is yet to develop similar matricies for other asset management competencies.	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.
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?	1.5	Interview comments indicate that communication of significant asset information (e.g. a change in an asset fleet's condition has been revealed) tends to be reactive and hurried.	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	Whilst Alpine has documented its asset management system well (and might therefore merit scoring a 3), the interviews note gaps. These gaps include people compiling their own data records because the official data is too hard to access, and doubtful data quality.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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	Alpine has a good conceptual understanding of its information requirements, which the Asset Data Strategy plans to build upon. In practice, there are deficiencies including doubtful data accuracy and completeness for some asset classes.	"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	The requirements for accurate data are well understood, and work is progressing on ensuring that asset condition data is both relevant and accurate.	"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.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.5	Alpine has a clear understanding of what its AMIS needs to provide, and work is progressing well in places.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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?	1.5	Whole-of-life asset risk particularly investment risk is not well documented, and seems ad-hoc.	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?	1.5	Although the Risk Management Policy sets out the requirement for specific actions, it is not clear that this has yet extended to training and competency. It is noted that there is great work happening to link asset condition and lifecycle risks to other activities such as inspections.	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	Alpine uses a range of sources to ensure that its obligations are correctly identified, and places actions on individual managers to ensure amendments are made.	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
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?	1.5	Alpine has an array of documented standards and policies for controlling all stages of the asset lifecycles that look good, but may lack robust lifecycle methodologies. In practice, however, there are variances ranging from possible occasional departures from design and material specifications through to more major concerns such as workflows being haphazard.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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?	2.5	Although strongly aligned documents are in place, Alpine has acknowledged that the use of Project Briefs to clearly define what Planning will provide to Engineering has lapsed due to busyness.	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?	1.5	Procedures for monitoring performance and condition are well documented, however the robustness of those procedures varies in practice. It is noted that great work is occurring to link inspection plans to condition data.	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 contractors 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?	2	Whilst the AMP documents how faults are investigated, it appears that communication paths within Alpine prevent clear and consistent communication of faults and defects to those who could drive corrective actions.	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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Some aspects of the asset management function are either regularly audited (due to statutory requirements such as financial audits, or the PSMS audit), whilst other audits and reviews may be ad-hoc.	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.

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Score	Evidence–Summary	Why	Who	Record/documented Information
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?	1.5	Leading mitigation of risks through comprehensive technical standards, policies and contracts is well done on paper, however it is widely acknowledged that day-to-day practices vary for a number of reasons including the interest of single individuals, roles remaining vacant and general business.	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	At a high level, various processes and practices are driving continuous improvement, but a common theme from the interviews is that the end-to-end process alignment and efficiency of work is poor. It is noted that work quality appears very good.	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.
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?	3	Although a wide range of sources for new technologies and practices (ranging from on-line searches to conferences) are used, it seems a bit ad-hoc rather than structured.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation 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.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13: Report on asset management maturity continued

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."
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."

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."
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."

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

Schedule 13: Report on asset management maturity continued

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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."
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."

Schedule 13: Report on asset management maturity continued

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."

Appendix E: Mandatory explanatory notes on forecast information

Schedule 14a

Company name: Alpine Energy Limited

For Year Ended 31 March 2023

Schedule 14a - Mandatory Explanatory Notes of Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015))

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.6.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

The nominal dollars capital expenditure forecast for 31 March 2023 represent the forecast actual capital expenditure the year ending 31 March 2023. The constant price for 31 March 2023 represents the forecast values as per the prior year AMP.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts (using 2024 real dollars) were inflated by 3.3% for 2025, 2.4% for 2026, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the 10-year forecast, 3.3% for 2025, 2.4% for 2026, and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 3.3% in 2025, 2.4% in 2026, and 2.0% in the other years.

Commentary on difference between nominal and constant prise operational expenditure forecasts (Schedule 11b).

The nominal dollars operational expenditure forecast for 31 March 2023 represent the forecast actual operational expenditure the year ending 31 March 2023. The constant price for 31 March 2023 represents the forecast values as per the prior year AMP.

To derive the operational expenditure in nominal dollar terms, the constant price forecasts (using 2024 real dollars) were inflated by 3.3% for 2025, 2.4% for 2026, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the 10-year forecast, 3.3% for 2025, 2.4% for 2026, and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 3.3% in 2025, 2.4% in 2026, and 2.0% in the other years.

Appendix F: Schedule 17 certification for year-beginning disclosures

We, Warren McNabb and Linda Robertson, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

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

Director	Director
6 April 2023	6 April 2023
Date	Date

24 Elginshire Street, Washdyke, Timaru 7940 **P.** 0800 66 11 77 **www.alpineenergy.co.nz**