# Asset Management Plan

2026 - 2036

Alpine ENERGY

# Contents

# 1. Introduction and Executive Summary

## 1.1. Introduction

The energy sector continues to evolve at pace, shaped by electrification, climate risk, digital transformation, and changing customer expectations. Alpine Energy's purpose remains to deliver safe, reliable electricity across South Canterbury, while building the capability and resilience needed for the future.

Achieving this requires us to respond to shifting demand patterns, support new forms of energy use, and manage the growing complexity of our network. We face rising expectations for affordability, performance, and transparency, alongside calls for greater sector collaboration and innovation. Our Asset Management Plan (AMP) sets out how we will meet these challenges through disciplined investment, structured planning, and continuous improvement.

### About the AMP

This section describes the purpose and structure of our Asset Management Plan (AMP).

### 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 maintaining and developing our electricity distribution network and supporting systems across South Canterbury. It outlines the asset management practices we use to deliver safe, reliable, and cost-effective services, and explains how our network and service delivery support our long-term strategy and strategic outcomes.

The AMP describes how we respond to the strategic drivers shaping our region, such as climate impacts, economic transformation, customer expectations, and regulatory reform. It outlines how we prioritise investment to meet future demand, manage risk, and maintain affordability. Our approach aligns with ISO 55000 Asset Management principles to maximise long-term value for our customers.

The scope of this AMP is limited to our regulated electricity distribution network. It does not extend to assets owned by subsidiaries or other business units.

We recognise that electricity distribution is complex and highly technical. This AMP makes a concerted effort to present our strategies, decisions, and activities in ways that are accessible to stakeholders, customers, and our people. Appendix A provides a glossary of terms.

This AMP is structured to meet the requirements of the Electricity Distribution Information Disclosure Determination (amendments related to IM review 2023) Amendment Determination 2024. Appendix B provides a cross-reference table showing how our AMP meets these requirements.

## AMP planning period

This AMP covers a 10-year planning period, from 1 April 2026 to 31 March 2036. 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, along with events and our own understanding of the condition of assets.

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 26 March 2026. The Directors' Certification is included in Appendix F.

## Navigating our AMP

**1. Introduction and Executive Summary**

Welcome from our Chief Executive and setting the scene for our AMP

**2. About Alpine Energy**

Overview of who we are and what we do

**3. Customer and stakeholder experience**

Our customers and stakeholders, their interests and how we engage with them

**4. Strategic Asset Management Plan**

Sets the direction for our Asset Management Plan.

**5. Asset management approach**

Insight into our asset management framework and practices

**6. Developing our future network**

Our network planning processes and an introduction to our energy roadmap

**7. Strengthening our network**

Our network growth projects in response to constraints and customer insights

**8. Supporting our network**

Our approach to the lifecycle management of our assets

**9. Risk and resilience**

Our risk context and our approach to risk management and building resilience

**10. What we need to spend on our network**

Our expenditure forecast and our top CAPEX and OPEX projects

**11. How we will deliver our AMP**

Our plans for successful AMP delivery and how we measure our success

**12. Appendices**

Additional supporting information and regulatory information disclosure schedules

## 1.2. Executive summary

This section provides an overview of our Asset Management Plan, structured around its key components.

### We develop, operate and maintain critical infrastructure that underpins South Canterbury's growth, safety and transition to a low-carbon future.

Our region is experiencing new patterns of growth, electrification, and climate risk, while our network is evolving to meet rising expectations for reliability, resilience, and customer choice. This section outlines the regional context in which our business operates and the characteristics of our network that shape how we plan, invest, and deliver.

### About South Canterbury

As a region, South Canterbury is diverse and complex in its electricity needs. This diversity is evident in the following key aspects:

- **Land use and economic activities:** Dairy, sheep and beef, and crop farming, food processing and other industrial operations, and tourism activity in the Mackenzie District.
- **Energy demand:** Significant industrial process heat requirements combined with seasonal demand driven by irrigation.
- **Geography and climate:** Stretching from the alpine village of Aoraki/Mount Cook to the temperate coast bordered by the Waitaki and Rangitata Rivers.
- **Population spread:** One significant urban centre (Timaru) and many smaller towns and villages throughout the region as well as remote rural connections.
- **Seven Grid Exit Points (GXPs):** A widely distributed set of supply points each serving distinct communities and industries. This configuration creates both resilience and complexity, with limited ability to balance load across GXPs and differing growth pressures at each location.

Our region's future is uncertain. We face critical uncertainties around climate risk, economic competitiveness, and customer behaviour. For example, we do not yet know how climate change will affect land use, water availability, or energy demand in the future. Communities are responding with solar, batteries, and microgrids to improve resilience. These trends are reshaping where and how people live, and how they expect to access electricity. Our strategy recognises these uncertainties and positions our business to adapt in step with and ahead of change.

## About our network

We own and operate the electricity distribution network that supplies over 34,000 homes and businesses across South Canterbury. Our network connects to the national grid at seven GXPs and includes sub-transmission, distribution, and low-voltage assets operating at voltages from 110kV down to 230V. It is a mix of overhead and underground infrastructure, spanning urban centres, rural communities, and remote alpine areas.

Our network is shaped by decisions made in the 1950s and 1960s. As we replace ageing infrastructure and upgrade core systems, we are laying the foundation for the next 50 years. We are modernising our network to meet future demands, support customer choice, and enable a low-carbon transition.

More than physical infrastructure, our network is a lifeline service that underpins South Canterbury's growth, safety, and transition to a low-carbon future. We are committed to maintaining reliability, enabling choice, and building the capability needed to meet the challenges ahead.

## We are reshaping how we engage with customers and stakeholders by building deeper, more genuine partnerships.

Our Customer Shift programme, launched in 2024, is driving organisation-wide improvements in service quality, transparency, and responsiveness. We are embedding a stronger service mindset across the business, supported by better systems and clearer processes.

Two-way engagement is now central to how we plan, invest, and deliver. We consult directly with commercial and industrial customers, run annual satisfaction and connection surveys, and host forums on energy wellbeing, flexibility, and equitable access. Our outreach includes regional safety campaigns, school programmes, and tailored communications for major projects. We also collaborate nationally through sector forums and peer Electricity Distribution Business (EDB) workshops.

Digital tools are improving how we engage. We've upgraded our Customer Relationship Management (CRM) system and are overhauling our website to support self-service and clearer communication. Our call centre model is evolving to provide 24/7 support, including fault dispatch and social media engagement.

Customer satisfaction is improving, with value for money and reputation driving gains. However, awareness and communication remain areas for improvement. We are responding by strengthening feedback loops, enhancing outage communications, and tailoring service options to meet diverse needs.

Looking ahead, we will continue to lift our engagement capability, supporting customer choice, enabling demand flexibility, and building trust through transparency and responsiveness. This is essential to delivering a network that reflects the needs and aspirations of the communities we serve.

We discuss more about customer and stakeholder experience in section 3.

## We have a clear strategy to deliver on our purpose in an evolving environment

Our strategy reflects the changing expectations of our customers and communities. It is anchored in our purpose, strategic outcomes, and the shifts we are making to respond to an evolving energy landscape. These shifts are shaped by the driving forces impacting South Canterbury's energy future, and guide the priorities and investments outlined in this AMP.

This framework – displayed in Figure 1 below – sets out our long-term direction and the changes we are making to stay aligned with what matters most to our customers, communities, and stakeholders.

*Figure 1 | Our purpose, strategic outcomes and big shifts*

## Our purpose

### Empowering our vibrant and thriving communities now and for the future

| Strategic outcomes | | Indicators |
|---|---|---|
| **Thriving communities** | **Our people and communities are healthy, safe, and thriving** | • Health & safety of workplace<br>• Public safety of the network<br>• Health of the environment |
| **Electricity for all** | **All electricity users can access and use electricity they need** | • Network accessibility<br>• Affordability<br>• Customer service |
| **Resilient and reliable electricity** | **Our electricity supply is resilient and adaptive in the face of climate change** | • Network reliability & resilience<br>• Planning, operations & delivery efficiency |
| **Financial sustainability** | **We have the capital and infrastructure to invest and deliver our strategy** | • Capital availability<br>• Dividends |

### Big shifts

- **Proactive collaborator:** from passive engagement to deliberate regional and industry partnerships
- **Customer choice:** from inflexible options to meeting broad range of customer needs
- **Smart infrastructure:** from manual and legacy processes to digitalised, integrated, and efficient systems
- **Financial resilience:** from dependence on few customers to broader mix of customers, pricing structures, and funding arrangements

## Driving forces impacting our customers and business

Our strategy responds to ten driving forces that are reshaping South Canterbury's energy future. These forces span economic, environmental, consumer, technology, and energy sector domains, and together they shape the assumptions and priorities in this AMP. Each driving force is described in Table 1 following.

*Table 1 | Our driving forces*

| | |
|---|---|
| **Economic drivers** | |
| **Structural economic change** | The region's future depends on New Zealand's approach to managing its future economic structure, such as land use, labour markets, and trade agreements. These flow through to how energy is used in the region. |
| **Demand for South Island food products** | South Canterbury's food sector is energy-intensive and exposed to global market preferences for sustainable products. Electrification of industrial processes is accelerating to meet these expectations, with implications for network capacity and resilience. |
| **Environmental drivers** | |
| **Climate impacts on South Canterbury** | Extreme weather events, storms, floods, fires, and high winds, are increasing in frequency and severity. These events are already disrupting supply and damaging assets. Communities are responding with decentralised energy solutions. |
| **Consumer drivers** | |
| **Consumer preferences** | Customers expect more autonomy, transparency, and reliability. They are investing in solar, batteries, and off-grid options, and expect flexible services and tailored engagement. |
| **Consumer energy resources (CER)** | Uptake of rooftop solar, batteries, and smart EV charging is rising slowly. These technologies require smarter network management to accommodate two-way flows and variable demand. |
| **Technological drivers** | |
| **AI and automation** | Intelligent systems are transforming how we maintain assets, forecast outages, and manage operations. |
| **Cybersecurity** | As we digitise our network, cyber threats are increasing in sophistication and frequency. |
| **Energy sector drivers** | |
| **Regulation** | Government and regulatory expectations are evolving, with greater focus on affordability, collaboration, efficiency, climate resilience, customer equity, and transparency. |
| **Workforce and skills** | Attracting and retaining skilled people is critical. As we digitise and expand our capital programme, workforce constraints remain a strategic risk. |
| **Network drivers** | |
| **Asset health** | Ageing assets and declining condition are raising failure risk. Asset condition data shows a need for accelerated, risk-based renewals to maintain reliability and manage maintenance costs. |

Together, these driving forces shape our strategic direction and ensure our AMP remains responsive, resilient, and aligned with the needs of our region.

See section 4.2. for more detail on our strategy and how it connects to our AMP.

## Our AMP responds to the driving forces shaping South Canterbury's energy future with clear priorities

Our AMP is grounded in clear assumptions and priorities that reflect our view of how the forces shaping South Canterbury's energy future will unfold over the next decade. These assumptions inform our AMP priorities and guide how we respond to risk, opportunity, and uncertainty across the network through targeted investment and delivery across three horizons to maintain reliability, enable transformation, and build future-ready capability. We outline below our AMP assumptions and priorities.

### Our AMP assumptions

Our AMP is informed by six assumptions about the driving forces shaping South Canterbury's energy future:

1. Electricity demand will grow steadily, driven by industrial decarbonisation and growth, with increasing contributions from electrification and distributed generation.
2. South Canterbury will experience increasing climate impacts and extreme weather events, with measurable effects on our assets and operations.
3. Our customers will increasingly require greater autonomy, resilience, choice and transparency, including participation in community energy resilience.
4. Artificial intelligence and automation will present significant opportunities to enhance network operations, productivity, customer service, and resilience.
5. Cyber threats to our networks and operations will continue to increase in sophistication and frequency.
6. Ongoing regulatory reform will increase focus on affordability, efficiency, collaboration, and resilience.

### Our AMP priorities

In response, our AMP sets out six priorities that guide how we plan, invest, and operate over the next decade. These priorities reflect the shifts we must make to meet changing customer needs, regulatory expectations, and environmental conditions. They are structured across three horizons – Horizon 1 (immediate uplift), Horizon 2 (transitional enablement), and Horizon 3 (long-term transformation). Our AMP priorities are:

- **Mature asset management and network operations:** We are strengthening our asset management maturity and operational capability. This means embedding lifecycle stewardship, improving data quality, and lifting planning discipline to ensure our day-to-day operations are reliable, efficient, and ready for future transformation.
- **Renew for reliability and service quality:** We are prioritising timely renewal of ageing assets to maintain service levels and meet regulatory standards. This ensures our network remains safe, resilient, and fit-for-purpose as climate impacts intensify and customer expectations evolve.
- **Secure capacity for growing demand:** We are expanding network capacity to support industrial electrification, housing growth and EV uptake. Our planning reflects confirmed step loads and incorporates flexibility to respond to emerging demand.
- **Strengthen climate and weather resilience:** We are embedding resilience into our planning and design standards to address increasing hazard exposure. This includes adapting asset strategies and uplifted renewals to ensure the network can withstand future climate conditions.
- **Meet evolving customer needs for flexibility and participation:** We are enabling customer-led energy use through flexible services, DER integration, and tailored planning. This supports fairness, autonomy, and resilience, particularly in rural and high-growth areas.

- **Lay the foundations for a digital, flexible future:** We are investing in digital systems, automation, and cybersecurity to support smarter operations and long-term adaptability. This prepares our business for future service models and positions us to respond to technological change.

These priorities ensure our AMP delivers on our strategic outcomes while remaining responsive to the region's changing energy landscape.

For more detail on our AMP assumptions and priorities, see section 4.3.

## We are delivering on our AMP priorities through three investment themes:

We structure our programme around three investment themes outlined below. We embed affordability into our investment planning by phasing delivery based on need, prioritising projects that deliver clear customer value, and validating key assumptions through independent assurance. We also create flexibility through non-network options and sector collaboration, ensuring investments remain efficient, sustainable, and responsive to community needs. Our three investment themes are:

### Investment theme 1: growth and enablement – developing our future network

We are developing our network to respond to rising demand, electrification, and changing customer needs across South Canterbury. Our network planning approach combines long-term scenario modelling, regional development plans, and real-time data to ensure we deliver capacity where and when it's needed. This work is guided by our Energy Roadmap, which helps us anticipate future load growth, test assumptions, and make informed decisions about infrastructure timing and scale.

We plan and optimise our network through a structured process that includes demand forecasting, options analysis, and regional Network Development Plans (NDPs). These NDPs are developed for each of our seven GXP regions and reflect local land use, economic activity, and customer growth. They ensure our network can meet both current and future demand while maintaining security of supply and power quality.

Managing the low-voltage (LV) network is a growing priority. Much of our LV infrastructure is ageing and was not designed for two-way power flows or emerging technologies like EVs and rooftop solar. We are improving visibility and control through smart meter data analytics platform, which uses smart meter data to monitor voltage, phase balance, and load patterns. This enables proactive management, better forecasting, and targeted deployment of both network and non-network solutions.

We will deliver this investment theme through a portfolio of projects, detailed in section 6. These projects are supported by broader planning and operational enhancements that together ensure our network remains capable, flexible, and ready for future growth.

### Investment theme 2: renewal and resilience - Investment to strengthen our network

We are strengthening our network to deliver safe, reliable and future-ready electricity services. Our approach involves targeted investment in the assets and systems that underpin our operations. This theme aligns network development with our long-term goals of resilience, efficiency, and customer service, and responds to emerging challenges such as climate change, decentralised energy, and evolving customer expectations.

We manage our network across the full asset lifecycle, operate, maintain, refurbish, and dispose. This is supported by real-time control, fault response, and proactive maintenance. Our network management approach includes automation, mobile field access, and advanced inspection technologies to improve safety, responsiveness, and decision-making.

Our fleet strategies guide investment in renewal and replacement across key asset classes: overhead structures, underground cables, zone substations, distribution transformers, distribution switchgear, and SCADA and communication systems. These strategies ensure consistent standards, prioritise risk-based interventions, and support long-term performance and cost efficiency.

We will deliver this theme through **nine material projects**, detailed in section 7. These projects are complemented by broader maintenance, vegetation management, and system improvements that together strengthen reliability, safety, and resilience across the network.

**Investment theme 3: Support and transformation – Investment for safe, efficient and responsive operations**

Our non-network investment program is a key enabler of safe, efficient, and responsive operations, with a strong focus on digital, fleet, and property assets. Digital investment is anchored in our digital strategy, which aligns with our driving forces and the broader industry transformation. Our ambition is to become digitally enabled, appropriately embedding digital in every aspect of our organisation, fostering continual digital reinvention, and actively collaborating across the industry.

We have made significant progress since launching our digital investment programme in the 2023 AMP, including consolidating our ERP and EAM implementation programme, automating workflows, deploying digital twins, advancing analytics, and strengthening cyber security. These achievements are modernising our architecture and have positioned us to conduct the next phase of transformation. Looking ahead, our focus for 2026-2028 is on completing the Target Architecture roadmap and building core digital and data capabilities. Our 2025 Horizon 1 Business Plan details the remaining investments needed to drive technological transformation and digitalisation, enabling effective asset and network management while laying the groundwork for future operating models and industry directions.

Beyond the next two years, we will accelerate investment in future technologies, targeting initiatives within three core strategic Accelerators (AI Driven, Future Technology Led, and Data & Information Ecosystem), supported by key enablers. These efforts will prepare our business for Horizons 2 and 3, driving industry collaboration, data interoperability, and positioning us at the forefront of a flexible, data-driven, and customer-centric energy system.

We will deliver this investment theme through a portfolio of material projects, detailed in section 8.

## Managing risk and resilience is central to how we deliver safe, reliable, and affordable electricity in a changing and uncertain environment

Our approach integrates risk management, asset lifecycle planning, emergency preparedness, and business continuity to ensure we can sustain operations under pressure and adapt to evolving threats.

We apply a structured risk management framework aligned with ISO 31000. This includes identifying and assessing risks, selecting treatments, and monitoring effectiveness across strategic and operational domains. Our governance model embeds accountability at all levels – from Board oversight to frontline delivery – and ensures risk is considered in every major decision. We prioritise risks that affect safety, service performance, regulatory compliance, and long-term network resilience.

We focus on high-impact, low-probability risks such as major earthquakes, severe weather, cyber intrusion, and supply chain disruption. We mitigate these through scenario planning, resilient design, critical spares, and coordinated emergency response. Our emergency management responsibilities are structured around the Four Rs (Reduction, Readiness, Response, and Recovery) and supported by strong partnerships with lifeline utilities and emergency services.

We use resilience intelligence and data-driven risk modelling to guide investment and operational decisions. Tools like Condition Based Asset Risk Management (CBARM) help us assess asset criticality and target interventions. We also invest in workforce capability, scenario-based training, and continuous improvement to ensure our people are ready to respond. During this AMP period, we will continue to embed risk awareness, strengthen climate adaptation, and support regional lifelines to improve resilience across our network.

For more detail on how we manage risk and resilience, see section 9.

## Our investment forecasts

### Independent review of our capital investment forecasts

To provide independent assurance over our capital expenditure forecasts we commissioned CutlerMerz[1] to review our ten-year asset investment portfolio. The review was undertaken to support potential engagement with the Commerce Commission for additional funding and assessed the robustness of our forecasts, the strength of our portfolio modelling and risk framework, and how our practices compare with more mature networks operating under similar regulatory expectations. The review found that our asset investment portfolio reflects a network facing increasing renewal, system growth and customer driven demands, and that many of our forecasting processes are appropriate for a business of our size, proportionate to available data, and supported by tools that provide strong locational risk insights. The review also concluded that our existing approach does not yet fully justify a sharp early uplift in Asset Replacement and Renewal expenditure and that targeted refinements are required to strengthen the transparency and consistency of our methods and to support confident engagement with the Commerce Commission.

The review identified proportionate improvements across the main network capital categories.

- For Asset Replacement and Renewal they recommended development of a structured historical cost database and standard unit rates, refinement of defect and likelihood assessments and the use of simple economic tools such as Expected Unserved Energy to support more consistent and defensible forecasts.
- For Reliability, Safety and Environment it recommended adopting trend-based approaches for recurring quality of supply issues and smoothing the currently front-loaded profile to better align timing with underlying needs and delivery capacity.
- For Consumer Connections it advised creating structured datasets and simple standardised models for unquoted and early-stage connections, alongside probability weighting for large spot loads, to reduce reliance on subjective judgement.
- For System Growth it recommended the incremental adoption of probability weighted spot loads, streamlined economic assessments that incorporate unserved energy and comparison of outcomes with and without investment to strengthen the justification for capacity and redundancy projects.

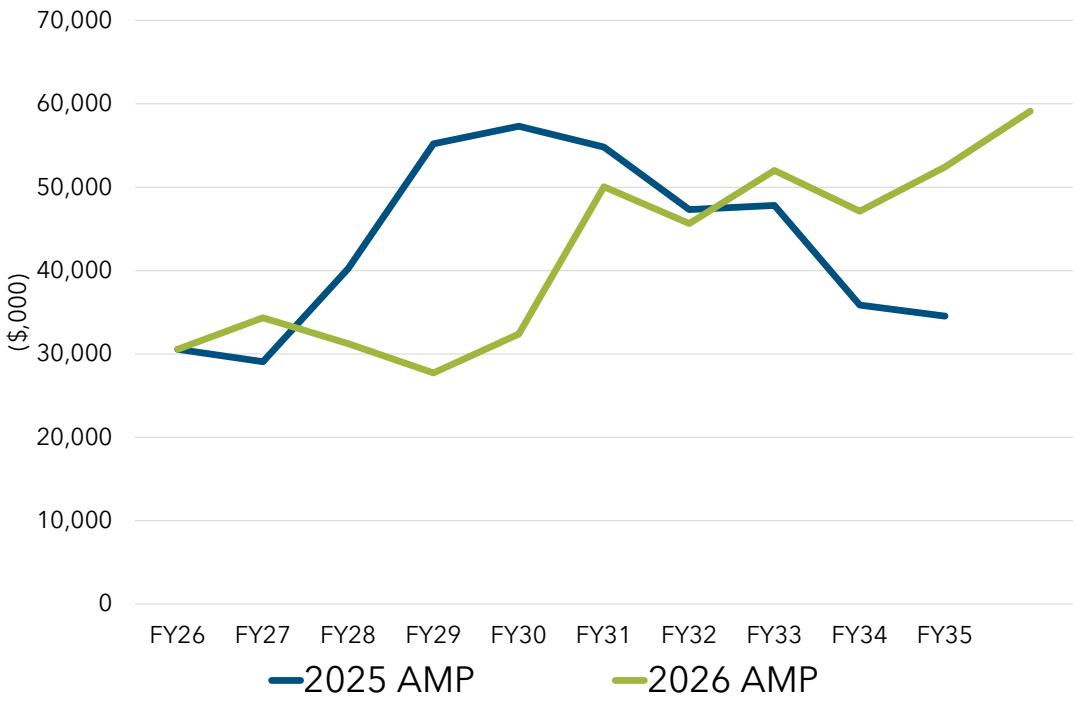
In response, we are reshaping our investment approach while preserving the overall scale and direction of the portfolio that the review validated. We propose to validate the Asset Replacement and Renewal profile through the middle of the decade while carefully managing any associated risk, and to draw on available regulatory tools. We are establishing an Asset Mastery Programme that will deliver a structured capability uplift and a consolidated and transparent prioritisation framework integrated with our ERP and enterprise asset management systems as part of Horizon 1. Taken together, these steps will lift our asset management maturity, improve the transparency and economic grounding of our capital forecasts, and provide a stronger basis for dialogue with the Commerce Commission on the prudency and efficiency of our long-term investment plans.

1 CutlerMerz is a specialist management, economic and engineering consulting firm that provides advisory services to the power and energy sector, with a focus on policy, regulation, networks, major projects and power system analysis.

## Capital expenditure

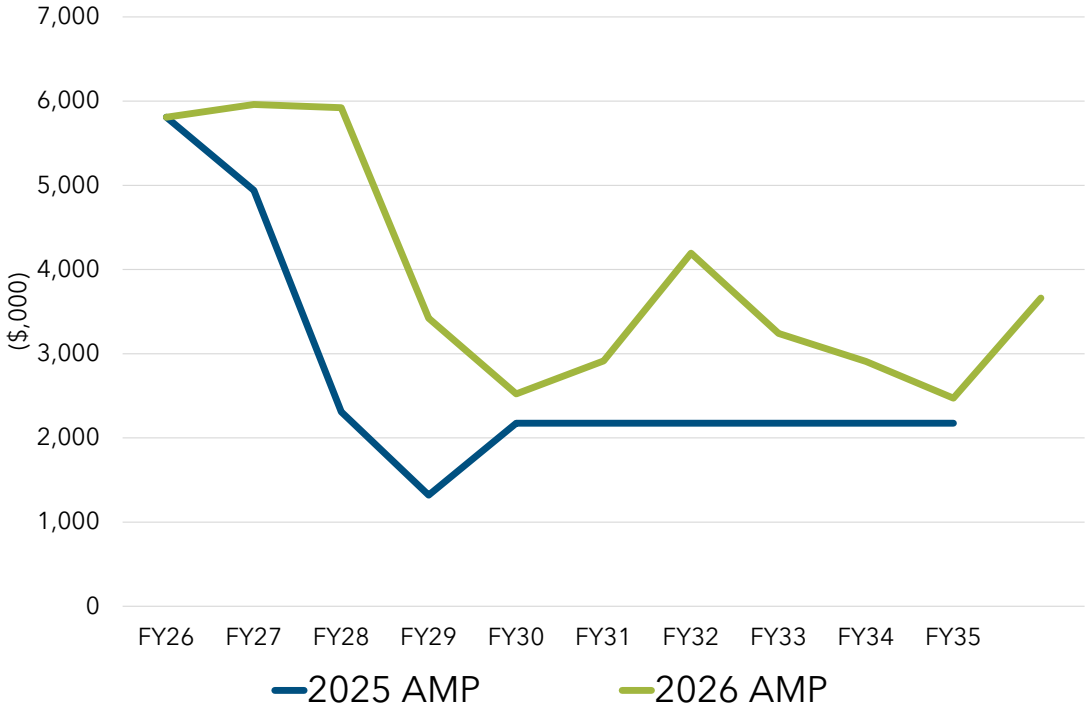
Over the next 10 years we are forecasting total network capital expenditure (CAPEX) of $432 million. In FY27, the planned expenditure rises above the previous AMP as critical renewal projects require investment. From FY28 to FY32, the 2026 AMP remains lower than the 2025 AMP, reflecting delayed demand growth expectations, more accurate condition information, and a focus on delivering the most critical renewal and resilience projects first. From FY32 onward, the trend reverses. This 2026 AMP rises above the 2025 AMP as major system growth projects begin to emerge. This uplift is necessary to ensure the network is prepared for future industrial electrification, potential step loads, and the long-term capacity requirements foreseen for Timaru. The smoother profile across the mid period also reduces the risk of over investment during uncertain years while maintaining our commitment to remain connection ready for new customers.

*Figure 2 | Network CAPEX - 2026-36 versus 2025-35 AMP*




Our total forecast non-network CAPEX is $37 million over the planning period. This represents an increase of $10 million from our previous AMP. This change reflects a shift from broad allowances to detailed and fully costed lifecycle planning of our plant, equipment and vehicles fleets.

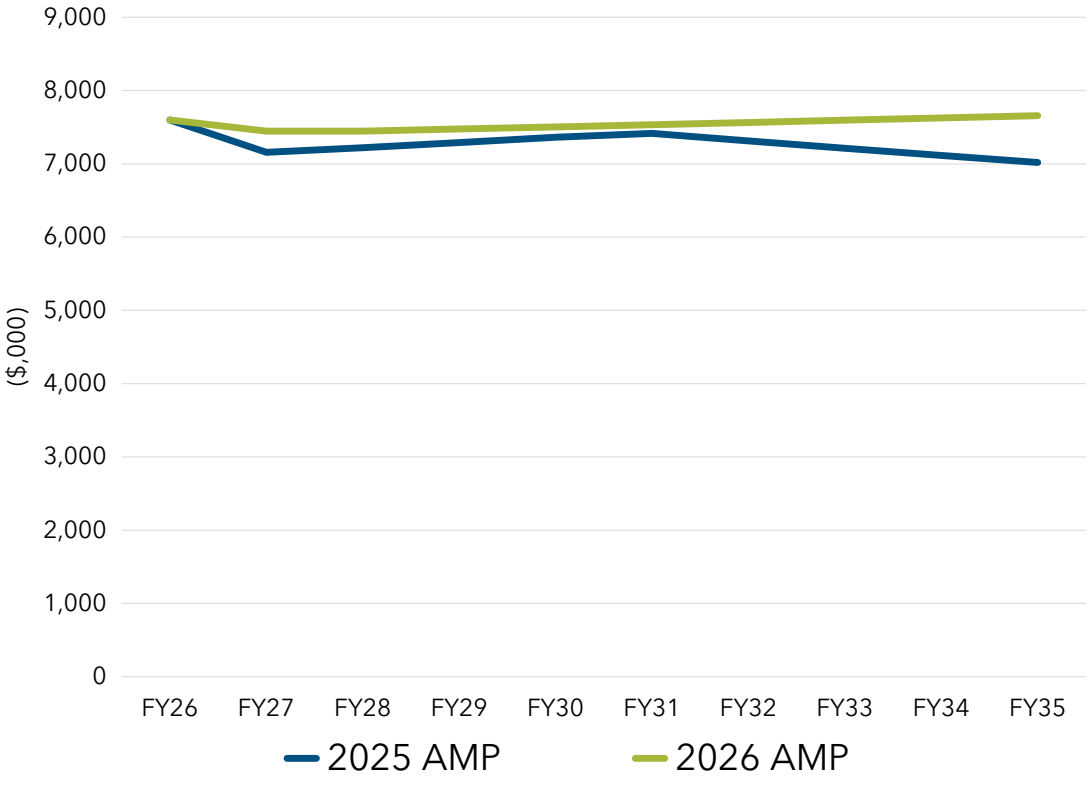
*Figure 3 | Non-network CAPEX - 2026-36 AMP vs 2025-35 AMP*




## Operating expenditure

Our network operating expenditure (OPEX) has increased to $76 million over the 10 years. This represents an increase of $3 million from our previous AMP for the overlapping 9-year period. This change reflects a higher forecast expenditure on vegetation management, and targeted adjustments to the routine maintenance of overhead lines.

*Figure 4 | Network OPEX - 2026-36 AMP vs 2025-35 AMP*



Our non-network operating expenditure has increased by $9 million across the ten-year forecast, rising from $284 million in last year's AMP to $291 million in this AMP.

Our non-network operating expenditure increases at the start of the forecast period as we deliver the transformation work required to modernise our core systems and improve the way we operate. The increase relative to the 2026 AMP occurs in FY27 and FY28, reflecting the step increase required to implement our transformation programme in the early years. Over the 10-year period, our forecast non-network OPEX has reduced from $272 million in the 2026 AMP to $262 million in this AMP. Around 75% of this expenditure relates to Business Support, with the remainder relating to System Operations and Network Support activities.

From FY29 onward our non-network operating expenditure reduces as transformation activity winds down and the benefits of more efficient systems and processes begin to flow through. This updated forecast reflects a moderated view of future cost pressures and a clearer understanding of the drivers behind these activities, indicating that the long term cost base can be sustained at a lower level without increasing operational risk or compromising service quality.

## We will deliver our AMP by strengthening our delivery approach, lifting productivity and collaborating across the sector

Delivering our AMP requires more than investment. It depends on the systems, capabilities, and partnerships that enable us to execute safely, efficiently, and transparently. Our delivery strategy reflects the scale and complexity of our planned works and the evolving expectations of customers, regulators, and stakeholders.

We focus on three core dimensions: strengthening our delivery model, lifting productivity across network delivery and operations, and collaborating for sector efficiency and innovation.

For more detail on how we will deliver our AMP, see section 11.

## Collaborating for customer outcomes

We are deliberately deepening collaboration as a core operating choice, consistent with the Minister's recent letter to the sector calling for EDBs to pursue greater efficiency, scale, and affordability through collaboration and integration. This is a conscious decision to change how we operate in order to deliver better outcomes for customers and communities.

A central part of this approach is the formal Heads of Agreement with Aurora Energy to progress a shared operating model. The two businesses are at complementary points in their strategic journeys, creating a strong foundation to combine strengths and learn from each other.

This collaboration creates a practical opportunity to build scale without losing local accountability. By working together, we can reduce duplication in systems, processes, and specialist roles, while retaining a strong regional presence and decision making close to customers. This is particularly important as both networks respond to growth, increased electrification, resilience pressures, and rising customer and regulatory expectations.

For customers, this approach is about better outcomes, not structural change for its own sake. Shared operating capability enables more consistent service, faster delivery of complex connections, improved outage response, and better coordination during major events. Over time, it also supports affordability by lowering long-term costs through shared investment in systems, tools, and specialist capability rather than each business funding these independently.

Alongside the Aurora agreement, we are continuing to strengthen collaboration with other EDBs, councils, lifeline utilities, and industry bodies. This includes shared delivery and assurance frameworks, joint procurement, coordinated planning of road and infrastructure corridors, and shared approaches to workforce development. These actions improve safety, reduce disruption for communities, and make better use of constrained skills across the sector.

Collaboration is also a deliberate lever for innovation and future readiness. By pooling data, insight, and investment, we can move faster on distributed energy resource integration, outage and control room capability, and more efficient customer connection processes. These are areas where scale directly improves customer experience and system performance.

Taken together, this represents a clear shift in how our business operates. We are moving from working largely on our own to operating as an active partner within a wider electricity system. This approach is aligned with Government expectations, builds on Aurora's experience, leverages our strengths, and positions both businesses to deliver more reliable, affordable, and resilient services for customers over the long term.

## Evolving our delivery model

We are evolving our delivery model to meet the scale and complexity of our 2026–2036 programme. We now operate an integrated field delivery model that brings together planning, engineering, and field services under one accountable structure. This enables us to directly manage a greater share of our works programme, improving responsiveness and execution.

We are also transitioning to a preferred supplier model for externally delivered work. This will improve cost certainty, delivery speed, and consistency of outcomes. Our delivery model supports safe, timely, and cost-effective execution of capital, maintenance, and customer-initiated works, while enabling continuous improvement and alignment with our strategic outcomes.

## Lifting our productivity

Productivity is a priority. We are digitising workflows, standardising designs and materials, and streamlining scheduling and supply chain processes. These changes will reduce duplication, improve cost visibility, and enable smarter decision-making.

We are also lifting productivity in network operations. This includes accelerating automation (e.g. remote switching), advancing our Outage Management and Advanced Distribution Management Systems (OMS/ADMS) roadmap, and deploying analytics to improve outage response and asset performance. We are embedding internal metrics to track efficiency and performance across delivery and operations, and investing in systems like AdaptiveWork, ERP, and GIS to support end-to-end visibility.

# 2. 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.

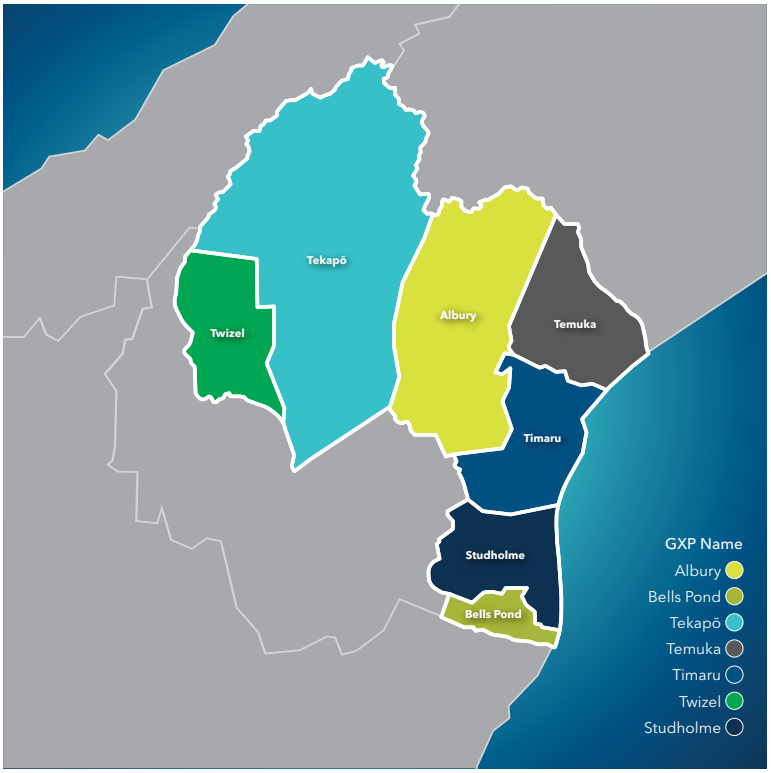
## 2.1. Our network

We are a non-exempt EDB and must comply with the Commerce Commission's Default Price-Quality Path (DPP) Determination. We proudly own, maintain, and operate the electricity distribution network that delivers electricity to over 34,000 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 5.

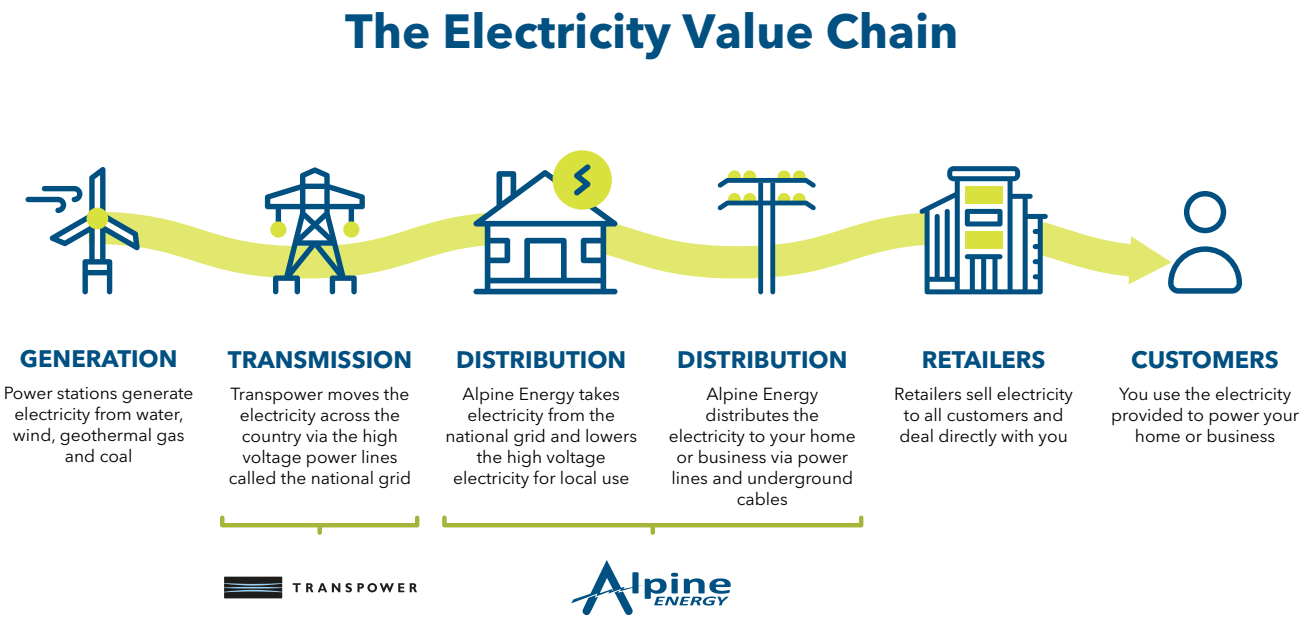
We have seven GXPs on our network as shown in Figure 5 below. The full overview and network configurations and schematic diagram for each GXP is included in Appendix C.

*Figure 5 | Our region*



## Our role in the electricity value chain

*Figure 6 | 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 multi-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 stakeholders to meet their energy needs and expectations

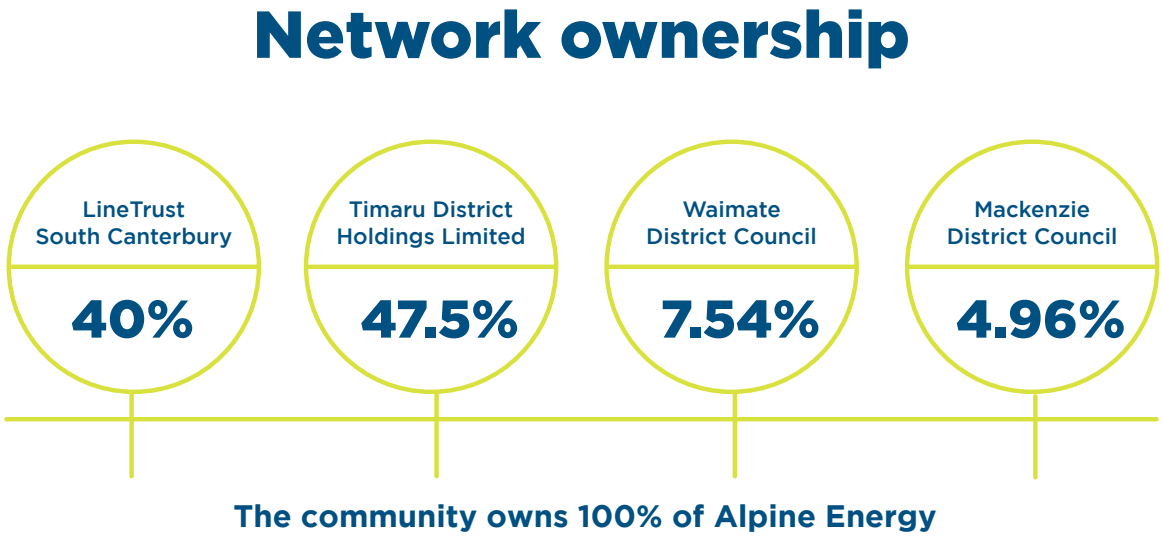
While we embrace the prospects, demands, and challenges of the future, we are conscious that we must also continue to provide long-term benefits to our customers through robust asset management planning, and service delivery at a quality that reflects the needs of our customers.

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.

*Figure 7 | Our network ownership*



# 3. Customer and stakeholder experience

Our customers and stakeholders expect clear information, timely communication, and genuine involvement in decisions that affect them. To meet these expectations, we are shifting from a traditional, asset-focused approach to one that puts people and communities at the centre of how we plan, invest, and deliver services.

Customer Shift, launched in 2024, is our organisation-wide programme to improve the quality, consistency, and transparency of every interaction. The focus is simple: better systems, clearer processes, and a stronger service mindset so it's easier for people to work with us, and us with them.

We are also taking a more structured and intentional approach to engagement. Two-way engagement is now a core part of how we shape our investment plans, service options, and long-term network strategy. This helps us understand changing needs early, manage options and trade-offs transparently, and build the trust customers and communities expect from their local lines company.

Effective engagement is not just a requirement, it is how we make sure our network remains safe, reliable, and ready for the future, while staying aligned with what matters most to the people we serve.

### Approach to new connections

For new customers, Alpine Energy follows a structured process from engagement to livening, including:

- Application and Assessment: Consumers submit a connection request via our online forms through our customer connections team. We have in place a CRM system to monitor customer enquiries and communications.
- Technical Review and Design: our engineering team assesses capacity, safety, and compliance with network standards. We then provide a detailed design and cost estimate, including where practicable considering optimal solutions to share customer costs.
- Construction and Commissioning: Work is scheduled based on resource availability by our Works Delivery and Field Services teams and completed to meet safety, technical and regulatory standards.

Indicative connection timeframes are:

- Simple: 4–6 weeks.
- Standard low-voltage: 4–16 weeks.
- Large commercial or subdivision projects: Vary depending on complexity.

Factors that can affect the connection cost and timing are addressed through early engagement and transparent communication. Common factors are capacity constraints, easement requirements, third-party consents (e.g., local council approvals) and equipment lead times for transformers or switchgear.

For customers altering their existing connection, our business applies similar steps, ensuring minimal disruption and compliance with safety and reliability standards.

### Minimising consumer costs

Our business seeks to reduce costs by:

- Offering standard connection packages for common simple and standard scenarios.
- Providing 'budget estimate' pricing where scope is clearly defined.
- Assessing the extent of any shared network infrastructure costs.
- Providing early advice on design options to avoid unnecessary works.
- Continuous improvement of process to reduce project delays.

### Customer communication

We maintain clear communication through:

- A dedicated customer connections team supported by a Customer Relationship Management system.
- Using dedicated Project Managers for complex projects.
- Supporting updates via email and phone during each stage.
- Online resources, including guides and FAQs, to assist consumers in understanding requirements.

### Sharing information on network constraints

Our business provides transparency on network capacity through:

- A Network Capacity Request available on our website and actioned by a customer connections and network planning teams.
- Network data shared upon request.

This ensures potential consumers can make informed decisions before committing to projects.

## 3.1. Identifying our stakeholders and their interests

| Stakeholder interests | |
|---|---|
| **Alpine Energy team** | Commitment to a safe and healthy work environment, as well as job satisfaction, diversity and inclusion, and opportunities to participate. Clear governance and management direction, responsibilities, accountability and productivity are essential. |
| **Civil Defence and Emergency Management (CDEM)** | Engagement and responsiveness in emergency management readiness, resilience, response and recovery. |
| **Communities and community groups** | Security of supply, safety, reliability, community partnerships, sponsorships, amenity, project impacts, energy efficiency education, climate change, and pricing. |
| **Contractors and service providers** | Fair access, steady workflows and timely information to support efficient resource planning and support, consistent terms with clear specifications and project diversity. |
| **Customers** | Urban Residential \| Rural Residential \| Urban Commercial \| Rural Commercial \| Large Customers \| Developers<br>Reliable electricity supply that is value for money - ensuring efficient fault restoration with good communication during events, ensuring availability of supply for customer and development needs. |
| **Distributed generation providers** | Reliable connection and communication. Pricing and value key to business. |
| **Financial institutions** | Prudent management and planning, especially regarding debt management and forecasting assumptions, timely and accurate information increasingly focused on our approach to sustainability. |
| **Government agencies – Commerce Commission, Electricity Authority, Work Safe** | Effective engagement on regulatory compliance, charges, consumer protection, environmental performance, safety and emergency management and response. |
| **Lifeline utilities** | Partnership and engagement in ensuring readiness, resilience, response and recovery. |
| **Local government** | Reliable, safe electricity supply for communities, alignment with spatial planning and growth, support for economic development and community wellbeing, engagement and responsiveness in emergency management readiness, resilience, response and recovery. |
| **Mana whenua** | Equity and energy affordability, regional development, and responsible stewardship of the natural environment. |
| **Retailers** | Reliable service and effective engagement to ensure ease of doing business. Cost and value key to business. |
| **Shareholders** | A fair return on investment, efficiency, long-term value, sustainability, prudent financial management, cost effective delivery, and security of supply for the communities our shareholders represent. |
| **Transpower** | Reliable load forecasting, swift communication of technical connection issues and details of new connection and investment planning. Security of supply is a shared interest with Transpower. |

### Resolving conflicting interests

We recognise that different stakeholders have different priorities – reliability, safety, affordability, and excellent customer service all matter. Sometimes, these interests conflict. To manage this, we:

- Always prioritise the safety of people and community.
- Align our asset planning with our strategic objectives and long-term vision.
- Balance affordability with service quality.
- Meet our legal and regulatory obligations.
- Use risk-based decision making.
- Offer flexible options to customers, not a one-size-fits-all.
- Engage regularly with different stakeholder groups.
- Be open about our reasoning – we clearly communicate risks, trade-offs, and opportunities.
- When conflicts arise, we always strive for consistency, transparency, and fairness.

## 3.2. How we engage

We use a mix of channels and methods to support two-way engagement with customers, communities, and other stakeholders, and act on what we learn:

- **Direct consultation:** We meet with commercial and industrial customers to understand their plans and energy needs, helping shape our demand forecasts and capacity planning.
- **Customer satisfaction surveys:** We conduct an annual satisfaction survey through independent researchers and, in 2025, introduced a Customer Connections Survey to improve new or expanding connections.
- **Community outreach and safety:** We participate in regional events, from A&P Shows to Think Smart Brain Days in local schools, focused on safety around our network and building community trust. Our 2024 farm safety campaign continues, alongside the expansion of our school safety programme. In 2025 we developed a library of seven repeatable safety campaigns covering topics such as reducing fire risk near assets, preparing for outages, safe DIY practices, and vehicle vs pole safety.
- **Stakeholder forums:** We engage through forums and initiatives that bring together communities to discuss energy wellbeing, demand flexibility, and equitable access to services. Examples include regional wellbeing and safety forums, collaborative workshops with councils and industry partners, and customer-focused sessions exploring energy use and network planning.
- **Sector-wide collaboration:** Across the customer and electricity distribution sector, we participate in initiatives such as the Community Energy Forum (CEF), Future Networks Forum (FNF), and peer EDB workshops. These forums allow us to share insights, adopt best practice, and drive innovation at a national level.
- **Major project engagement:** For significant infrastructure works, our service delivery and communications teams collaborate to provide targeted, tailored communications and one-on-one support to affected landowners and communities. Project-level engagement has grown in recent years, including hosting community hubs that bring together staff and residents to celebrate projects, thank the community, or provide support during prolonged outages. We also run multi-channel campaigns ahead of major works, highlighting project rationale, customer investment, and targeted safety messages such as traffic management.
- **Digital engagement tools:** In 2026, we are upgrading our website to improve customer experience, make information easier to find, strengthen our main communications channel, support our refreshed brand, and overhaul content for clarity and usability. Our CRM system, introduced in 2024, continues to improve how we track, manage, and respond to customer needs.

- **Public campaigns:** We run seasonal and topical campaigns across radio, print, digital, and social media, focusing on safety, efficiency, and reliability. Campaigns are tailored to different audiences and coordinated across the business, including proactive messages during planned outages, emergency response situations, and PIM-led communications during events.
- **Call centre and online experience:** We're continuing to lift the quality, consistency, and responsiveness of customer service across all channels (phone, email, and online). As part of this, we are progressing a move to a new call centre model. This includes outsourcing the management of all incoming customer calls on a 24/7 basis, covering out-of-hours faults dispatch and all social media enquiries and includes a new KPI framework and performance targets.
- **Media:** We share timely, accurate information through different media channels, covering planned and unplanned outages, business strategy and future planning, environmental protection initiatives, cost and price updates, issues management, and our contributions to local communities.
- **Local government and regulators:** We coordinate with local councils on infrastructure, consenting, and emergency planning. We also regularly engage with regulators (like the Commerce Commission) and industry groups (ENA, EEA) on standards, risk, and long-term planning.

## Customer feedback and complaints

We treat complaints as opportunities to improve. Our approach:

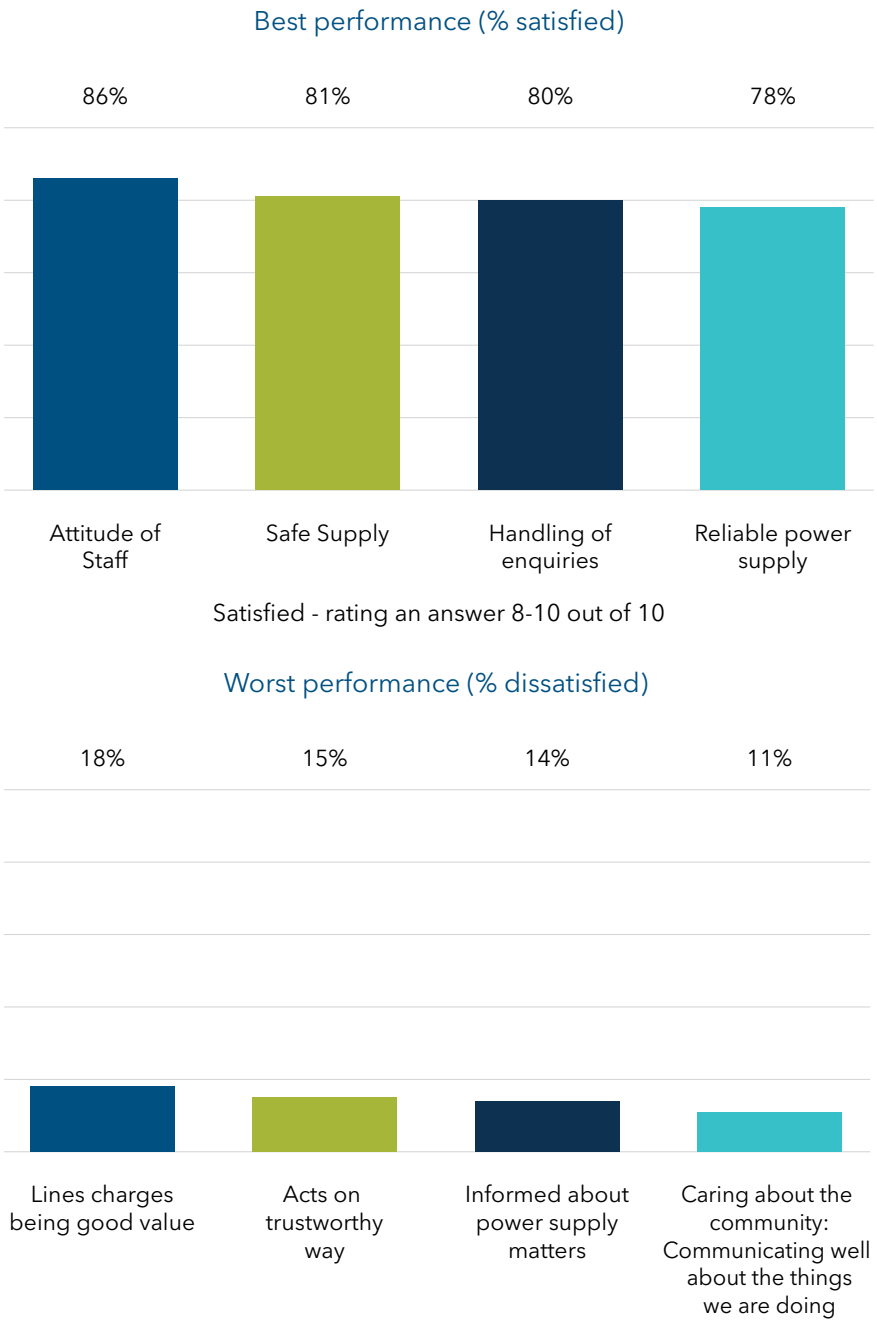
- Streamlined and transparent complaints process.
- Dedicated resources to manage and resolve complaints promptly.
- Workflow maps to ensure consistent resolution.
- Customers are informed of their right to escalate to Utilities Disputes Ltd (Electricity Industry Participation Code).
- High-resolution rates and strong feedback for our personal, open approach.

## 3.3. Customer satisfaction and insights

Our Customer Satisfaction Survey (CSS) offers key insights into customer views of our service, areas of improvement and customer trends.

In 2025, our CSS captured feedback from 400 customers across residential and commercial, urban and rural segments Satisfaction is at a four-year high, rising from 50% last year to 55% this year.

*Figure 8 | 2025 CSS feedback*




Overall satisfaction improvement largely driven by the increase in satisfaction with **value for money** and **image & reputation**, the strongest driver of overall performance.

**Reliability 70%** – top performance area (+6pts delivering safe power supply, +6pts providing a reliable power supply).

**Communication 53%** – steady, need more proactive updates

**Value for money 37%** – (+4pts), lowest performance, biggest improvement driver

**Awareness: 64%** (-10pts) – fewer customers recognise us

**Satisfaction improvement** led by Residential Urban. Rural & Commercial segments remain steady but cautious, especially around cost, value, and communication.

**Pricing preference** – 56% prefer fixed charges; 31% usage-based

**Technology adoption** – the likelihood of installing or purchasing new technologies remains low across all customer groups. However, the likelihood of installing solar PV panels has increased significantly, from 4% in 2024 to 9% in 2025. 73% use LED lighting (+9pts), 9% plan to go solar in 2–5 years, 10% were interested in EVs (trending down) with a lower willingness for Alpine control, and nearly 60% of rural/business customers have no backup supply.

### Key priorities for improvement

- Lift awareness of our role & purpose
- Improve value perception – transparency & community benefit
- Strengthen communication – timely, relevant, accessible, especially outages and project updates
- Enhance image and reputation – need to demonstrate community care, being progressive and being efficient which will strongly influence satisfaction
- Protect and promote strengths – reliability, safety & helpful staff

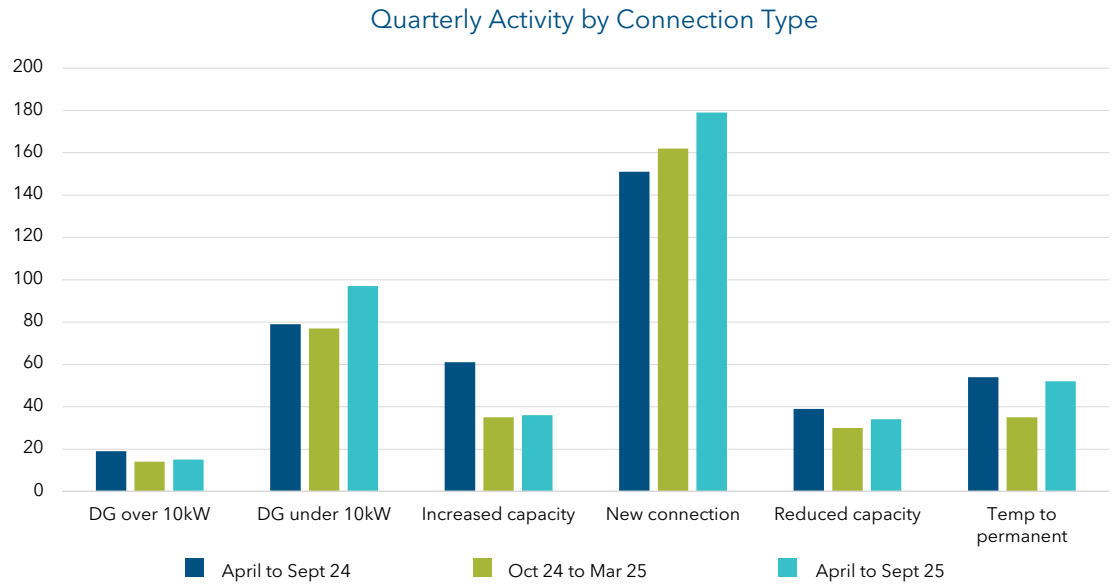
We will continue to build on these insights as we evolve our engagement approach to meet changing customer expectations and regulatory requirements.

## Customer connections activity

Our CRM and ARC (Registry Management) systems have been in place for 12 months and continue to improve how we capture and manage customer activity on our network. This has strengthened our understanding of customer needs and data. We are also using these insights to better inform our works programmes across the business.

Figure 9 below illustrates a selection of customer activity where levels have increased. In general, activity is consistent or increasing from historical levels. Connection enquiries and small scale distributed generation (DG) connections have increased by over 20% compared to a year earlier.

*Figure 9 | Overview of customer activity levels*



## 3.4. Customer shift programme

Our customer connection processes remain highly manual and no longer meet evolving commercial or regulatory expectations. To address this, we are implementing the Customer Shift Programme, which builds on recent system enhancements (CRM and ARC) to redesign the end-to-end connection journey. By incorporating customer and industry insights and modern process design, the programme will strengthen customer experience, improve operational efficiency, and ensure alignment with sector standards and regulatory requirements.

Delivery will span FY26–FY27, beginning with scoping activities and quick-win improvements, followed by detailed programme design, communications planning, and impact assessments. Implementation will include updates to online channels, improved CRM–ARC integration, the development of PowerBI reporting, and updates to policy and guidance documents.

### EECA initiatives

Over the past 12 months, we have begun two major programmes of work with EECA that support decarbonisation and smarter use of our existing network. Both initiatives strengthen our understanding of industrial energy use and help us collaborate with customers on reducing emissions, increasing efficiency, and managing demand.

**1. Alpine Energy–EECA Energy Professional Programme**

This programme accelerates decarbonisation in South Canterbury by identifying and supporting industrial sites that can transition from coal and diesel boilers to electric alternatives. The initiative began with a detailed data analysis, mapping commercial and industrial customers against emissions information from Environment Canterbury to identify high-impact sectors and sites.

From 6,867 customers, 1,179 potential emitters were identified, with 34 priority sites shortlisted for electrification readiness assessments. The programme also explores opportunities for energy efficiency, fuel switching, and demand flexibility, supporting regional energy strategy development and scalable long-term emissions reduction.

Beyond electrification, the programme addresses broader challenges such as:

- Grid capacity constraints
- Regulatory and technical barriers
- Stakeholder readiness and cost considerations

Engagement with EECA is now underway, with up to 20 sites as determined. Tailored engagement plans will be developed to support decarbonisation options that align with both customer needs and network capability.

**2. Alpine Energy–EECA Distributed Flexibility Pilot**

This pilot explores industrial demand flexibility as a strategic response to network constraints in two high-growth areas, the Timaru Port and Washdyke, which together represent 16% of annual energy consumption but only 1% of customers.

The programme focuses on opportunities for customers to shift or reduce energy use during peak periods to defer costly upgrades and improve network resilience. This aligns directly with our asset management objectives of optimising existing infrastructure, reducing long-term investment pressure, and improving security of supply.

The pilot will:

- Identify suitable industrial partners
- Assess flexibility potential and technical feasibility
- Evaluate impacts on network performance
- Inform future flexibility products and commercial arrangements

Both EECA initiatives support our long-term strategy by combining data, customer insights, and sector partnerships to deliver practical pathways toward decarbonisation and smarter network use.

## How customer needs inform our programme

Our investment planning reflects what we hear from customers and stakeholders. Through surveys, complaints insights, direct conversations with commercial and industrial customers, community engagement, and feedback during outages and project work, we build a clearer picture of what people value most. Common themes include reliability, safety, clear communication, and support during planned and unplanned events.

We use these insights to help shape our long-term network strategy, guide prioritisation of projects, and ensure our plans reflect changing expectations. While our customer insight tools are still maturing, incorporating customer needs into decision-making ensures we are balancing affordability, service quality, and future resilience in a way that aligns with what matters to our communities.

## Looking ahead

Customer Shift marks a major step forward in how we serve customers. As energy use becomes more complex and decentralised, we are moving from basic service provision to offering flexible, transparent, and customer-led options, from connection arrangements to communication channels and support for emergency preparedness.

Over the next AMP period, our cross-organisation programme will focus on improving experience across all touchpoints. Key priorities include:

- Easier customer engagement, for customers and for us.
- Clearer communication during outages, works, and new connections.
- Smarter digital tools that reduce effort and improve satisfaction.
- Stronger feedback loops that lead to real improvements.
- Greater trust and transparency with all stakeholders.

## Insights driving this shift

- Our digital channels do not support modern expectations for self-service or two-way engagement.
- Communications remain largely reactive, especially during outages and planned work.
- Customer satisfaction sits below industry averages.
- Regulatory expectations continue to rise, requiring meaningful engagement on service options, cost trade-offs, and long-term plans.

## Our commitment

We are committed to becoming a responsive, future-ready distribution business that puts customers and communities at the centre. This includes stronger engagement with industrial customers to understand their needs, offering demand-flexibility solutions that support smarter investment, and updating our pricing and connection processes to meet new industry standards. We are also strengthening our customer connection processes, digital capability, and demand-flexibility partnerships to support smarter planning and better service delivery.

As the energy transition accelerates, we will continue to build on our progress, listening, adapting, and partnering with our communities, while further lifting our digital capability and customer experience. While we have made significant strides in engagement over the past few years, we remain focused on improvement, because meaningful engagement is essential to building trust and shaping a better energy future for our region and across New Zealand.

# 4. Strategic Asset Management Plan

## 4.1. Purpose and overview of the Strategic Asset Management Plan

The Strategic AMP sets the direction for the rest of our Asset Management Plan. It acts as a strategic foundation, linking our long-term strategy and strategic context to the detailed planning, investment, and delivery components of the AMP.

Our strategy responds to the **driving forces** reshaping South Canterbury's energy future. Our vision for our role in that energy future is reflected in the four **big shifts** at the core of our strategy, which capture how we are thinking about our role, our investments and the capabilities we need to build in the next 10 years and beyond.

These driving forces and big shifts guide our AMP assumptions and shape our investment priorities across three horizons.

The Strategic AMP has three main components:

- **AMP assumptions** that articulate our expectations for the future across key strategic outcomes and that shape our asset management priorities
- **AMP priorities** structured across the three strategic horizons; and
- **Investment themes** and the material projects under each theme that deliver on the AMP priorities.

Figure 10 following illustrates how these elements connect to our long-term strategy, supported by strong foundations in asset management, risk management, and delivery.

*Figure 10 | Overview of our Strategic Asset Management Plan*

## Our purpose

**Empowering our vibrant and thriving communities now and for the future**

## Our strategic outcomes

**Thriving communities** | **Electricity for all** | **Resilient and reliable electricity** | **Financial sustainability**

## Our driving forces

Ten **driving forces** impact our customers and business:

- **Structural economic change**
- **Customer preferences**
- **Cybersecurity**
- **Demand for South Island food products**
- **Consumer energy resources**
- **Regulation**
- **Asset health**
- **Climate impacts on South Canterbury**
- **AI and automation**
- **Workforce and skills**

## Our ambition

In response, we have set a clear **ambition for Alpine in 2035, shaped by four shifts:**

**Proactive collaboration** | **Customer choice** | **Smart infrastructure** | **Financial resilience**

## 2026-35 AMP priorities

Our AMP is informed by six **assumptions** on our driving forces:

1. Electricity demand will grow steadily, driven primarily by industrial activity
2. Climate impacts and extreme weather events will increase
3. Customers will require greater autonomy, resilience, choice and transparency
4. AI and automation will present opportunities to enhance operations and service
5. Cyber threats will increase
6. Regulatory reform will increase focus on affordability, efficiency, collaboration and resilience

... these define six **priorities** for our 2026-35 investments and actions:

1. Mature asset management and network operations
2. Renew for reliable and service quality
3. Secure capacity for growing demand
4. Build climate and weather resilience
5. Meet evolving customer needs for flexibility and participation
6. Lay the foundations for a digital, flexible future

... that we will deliver through three **investment themes:**

**1. Renewal and resilience** | **2. Growth and enablement** | **3. Support and transformation**

## AMP foundations

... and continue to strengthen **three foundations** for the effective delivery of the AMP:

**Asset and network management** | **Risk management and resilience** | **Delivery, productivity and collaboration**

## 4.2. Our strategy

Our strategy provides the foundation for the Strategic AMP, ensuring that our investment decisions and operational priorities are aligned with our long-term vision. This section sets out the core elements of our strategy: the **strategic outcomes** we are working towards, the **driving forces** shaping our region and business, and the **big shifts** we are making to respond to these challenges and opportunities. Together, these elements guide the priorities and investments that underpin the Strategic AMP and position our business to deliver reliable, sustainable, and future-ready electricity services for South Canterbury.

### Our purpose and strategic outcomes

Alpine Energy operates in a period of profound change across the electricity distribution system. Electrification, digitalisation, and shifting customer expectations are transforming how distribution businesses plan, invest, and deliver services. Our purpose is to deliver an essential lifeline service that supports and enables South Canterbury's economic growth and New Zealand's transition to a low-carbon economy.

Over the past three years, we have repositioned ourselves as a safer, more customer-focused business. We are building our digital and asset management foundations from the ground up, strengthened leadership and governance, and lifted organisational capability. We now deliver higher levels of capital programmes at more than twice historic levels and are better placed to meet future demands while supporting community needs through strategic partnerships.

Our long-term strategy sets out how we will navigate this environment and deliver four strategic outcomes:

- **Thriving communities:** our people and communities are healthy, safe, and thriving for the long term.
- **Electricity for all:** all electricity users can access and use electricity they need.
- **Resilient and reliable electricity:** our electricity supply is resilient and adaptive in the face of climate change.
- **Financial sustainability:** we have the capital and infrastructure to invest and deliver our strategy.

### Driving forces for our region, customers and business

Our operating environment is shaped by a set of ten strategic **driving forces**. These are the major external factors that will influence our customers' needs and our business decisions over the next decade, spanning economic, environmental, consumer, technology, and energy sector domains. We define each driving force below and explain why it matters for South Canterbury and our business. These forces inform investment prioritisation and the assumptions set out in this AMP.

## Economic driving forces

### Structural economic change

Structural economic change refers to how New Zealand's economy might evolve in its foundational makeup, whether the government takes a "hands-off" approach to managing its future economic structure or deliberately invests in change. The structure of the economy determines the demand for energy and the resilience of our customer base.

South Canterbury's economy today is heavily driven by agriculture, food processing, and related manufacturing. These sectors are energy-intensive and form the backbone of our network's commercial and industrial load. However, our region's future prosperity depends on how successfully it adapts to broader economic shifts.

Deliberate diversification into advanced agribusiness and other industries could introduce new large-scale energy users and broaden the sectors we serve. This would necessitate growth investment and create opportunities for strategic investment in capacity, connections, and service innovation. Conversely, if traditional industries decline without replacement, the region risks population loss, reduced network utilisation, and greater affordability pressures.

### Demand for South Island food products

Global demand for South Island food products reflects how New Zealand's trading partners value low-carbon, high-quality agricultural exports. This includes formal mechanisms like carbon border adjustment measures (CBAMs) and informal market preferences for sustainably produced goods. For South Canterbury, where dairy, meat and food processing dominate the regional economy, this driver is critical. The competitiveness of our producers in global markets directly influences the growth of our commercial and industrial customer base and their demand for clean energy supply.

South Canterbury's food sector is energy-intensive and forms a large share of our network load. As international buyers increasingly favour low-emissions products, local processors are electrifying operations to remain competitive. Fonterra's conversion of coal boilers to biomass is a clear signal of this shift. If our region continues to meet global expectations for sustainable food production, we will see stable or growing demand from large customers, enabling investment in capacity and resilience. If demand falters due to emissions constraints or shifting trade dynamics, industrial closures could follow, reducing load and impacting affordability as fixed costs are spread across fewer users. Our exposure to this driver is high, and we will continue to monitor trade policy, decarbonisation trends, and the strategic choices of our largest food sector customers.

## Environmental driving forces

### Climate impacts on South Canterbury

Climate impacts refer to extreme weather events – storms, floods, fires, and high winds – that affect South Canterbury's communities and infrastructure. These events are intensifying and are already disrupting electricity supply, damaging assets, and influencing where and how people live.

South Canterbury has experienced multiple severe events in recent years, including high wind events across the Mackenzie District, flooding in Canterbury rivers, and snowstorms that have stressed assets and disrupted supply. The Canterbury Climate Change Risk Assessment predicts that the frequency of extreme weather events is likely to increase, with drought and sea level increases also expected. In 2021, extreme rainfall events that caused flooding in Canterbury were 10–15 percent more intense than historic events because of climate change. In October 2025, wild winds exceeding 155 km/h affected the South Island, including Canterbury, leaving thousands without power and prompting a declaration of a state of emergency in Canterbury.

These impacts are already influencing customer behaviour. Some communities are relocating due to insurance retreat, while others are investing in solar and batteries to improve resilience. For us, this means higher restoration costs, more complex investment decisions, and a need to build resilience into every aspect of our planning. Climate impacts are not a future risk, they are a present reality, and they will shape our network, our customers, and our role in the region.

## Customer-related driving forces

### Consumer preferences

Consumer preferences are shifting toward greater autonomy, resilience, and choice in how energy is sourced and used. Customers increasingly expect personalised services, transparent pricing, and the ability to participate in energy decisions. This includes interest in non-network solutions such as solar, batteries, and home energy management systems, as well as preferences for sustainable energy and reliable supply during disruptions. These expectations are reshaping the relationship between our business and our customers, from passive consumption to active engagement.

In South Canterbury, we are seeing growing interest in energy independence and resilience, particularly following recent storms and outages. Households and businesses are investing in solar and battery systems to maintain supply during emergencies. Remote tourism operators and high-country properties are exploring off-grid options. Larger customers are demanding higher security of supply, including N-1 connection arrangements. If we do not respond with flexible connection options, tailored service models, and transparent engagement, we risk losing trust and relevance. Our strategy recognises this shift and positions us to meet evolving customer needs through smarter infrastructure, proactive collaboration, and customer-centric service design.

### Consumer energy resources

Consumer energy resources (CER) are technologies that allow customers to generate, store, and manage their own electricity, such as rooftop solar, batteries, smart electric vehicle (EV) charging, and home energy management systems.

In South Canterbury, CER adoption is increasing, particularly among higher-income households and commercial customers. These technologies are rapidly advancing in technical maturity while technology cost is declining, driving growing uptake among consumers seeking resilience and cost savings. As CER uptake grows, our network must accommodate more two-way flows, variable demand, and new connection types. This creates both challenges and opportunities. Poorly integrated CER can strain voltage and asset performance, while well-managed CER can defer investment and improve reliability.

## Technological driving forces

### AI and automation

AI and automation refer to the growing use of intelligent systems and digital tools to improve decision-making, streamline operations, and reduce manual intervention. These technologies are advancing rapidly and are increasingly relevant to EDBs. For our business, this driver is about how we use data and automation to manage a more complex, decentralised network and deliver better outcomes for customers.

AI can transform how we achieve operational efficiency and resilience. It enables predictive maintenance, outage forecasting, and asset condition assessment, replacing expensive methods like LiDAR with lower-cost image recognition and large language model (LLM) analysis. Automation supports faster restoration, smarter crew dispatch, and more efficient business processes. We expect to move quickly toward probabilistic modelling and scenario planning, reducing overhead and manual effort.

AI and automation also underpin broader trends shaping our future network capability, including:

- Smart grids and advanced network management
- Data analytics, AI, and digital twins

- Automation and IoT in grid operations
- Customer digital engagement and prosumer participation
- Industry collaboration for shared platforms and innovation.

These trends will reshape how we plan, invest, and deliver services over the next decade.

### Cybersecurity

As our network becomes more digital and interconnected, the risk of cyber threats increases. These threats range from ransomware targeting corporate systems to more sophisticated attempts to compromise control systems and critical infrastructure. AI is fundamentally reshaping the nature, ease, and volume of these threats, enabling attackers to automate exploits, craft highly targeted phishing campaigns, and scale attacks at unprecedented speed and complexity.

Our exposure to cyber risk is growing as we embed smart infrastructure, automate operations, and expand data-driven services. A successful attack could disrupt electricity supply, compromise customer data, and damage public trust. The energy sector globally has seen a surge in ransomware and targeted attacks, and New Zealand's regulators are increasing expectations around cyber resilience. In response, Electricity Distribution Businesses (EDBs) are actively collaborating to establish common cybersecurity standards and strengthen collective response capabilities, ensuring sector-wide resilience against evolving threats.

For our business, this means investing in robust protections, training staff, and ensuring we can respond to and recover from cyber events. It also means preparing for tighter compliance requirements and reputational scrutiny.

## Energy sector-related driving forces

### Regulation

Our regulatory environment is the legislative and policy frameworks that govern how electricity distribution businesses operate, invest, and recover costs. This includes the Commerce Commission's price-quality regulation under Part 4 of the Commerce Act, as well as broader government expectations around collaboration, scale efficiency, transparency and customer outcomes.

Over 90% of our revenue is regulated. Any changes to how price paths are set, how performance is measured, or how investment is incentivised will directly affect our ability to deliver reliable, affordable services. The government has signalled concern about fragmentation in the sector and is encouraging greater collaboration and efficiency. We are actively responding by leading collaborative initiatives with the sector across the South Island to reduce duplication, build capability, and deliver more efficient outcomes. We also anticipate increased scrutiny on climate resilience, customer equity, and innovation.

### Workforce and skills

We require workforce capacity and capability to deliver our strategy and operate a modern electricity distribution business. This includes technical roles such as line mechanics, engineers, and planners, as well as emerging digital and data-focused roles. National settings, such as immigration policy, education funding, and industry training, shape the pipeline of talent available to our business and the wider sector.

Our ability to attract and retain skilled people is critical to delivering safe, reliable, and affordable services. South Canterbury competes with larger centres for talent, and our workforce needs are evolving as we digitise operations and expand our capital programme. Workforce constraints remain a strategic risk. If we cannot access the skills we need, delivery slows, costs rise, and safety and quality may be compromised.

### Our 2035 ambition and strategic shifts

By 2035, we aim to be a trusted, adaptive, and community-focused energy partner for South Canterbury. We will deliver resilient and affordable services, enable customer choice, and use data and technology to create lasting regional value. We will be known for empowering our communities, earning trust through transparent engagement, and being a preferred employer with a strong culture and purpose. Our network will be reliable, flexible, and climate-resilient. Our services will support customer autonomy and integrate modern energy solutions such as batteries, microgrids, and community-based generation. We will embed data and technology into planning and operations, and maintain readiness for regulatory and market change.

To achieve this ambition, our strategy is anchored in four **big shifts**:

- **Proactive collaborator:** We are moving from passive engagement to deliberate regional and industry partnerships. We are leading joint planning, shared workforce models, and co-investment in resilience and sustainability. This shift strengthens our role in shaping South Canterbury's energy future.
- **Customer choice:** We are transitioning from inflexible service models to meeting a broad range of customer needs. We are tailoring connection options, improving communication, and co-designing solutions with customers. This shift builds trust and ensures our services remain relevant and inclusive.
- **Smart infrastructure:** We are replacing manual and legacy processes with digitalised, integrated, and efficient systems. We are developing Distribution System Operator (DSO) capability, using analytics to uplift network resilience and reliability, and improving safety and visibility, and optimise investment.
- **Financial resilience:** We are shifting from reliance on a few large customers to a broader mix of customers, pricing structures, and funding arrangements. We are strengthening forecasting, exploring new revenue models, and aligning investment with long-term affordability. This shift ensures we can sustain dividends and reinvest in the network under changing conditions.

Together, these shifts position us to respond to uncertainty, deliver on our strategic outcomes, and support a thriving, low-carbon future for South Canterbury.

## Network driving forces

### Asset health

Much of our network was built in the 1950s - 1960s and is now approaching or beyond end-of-life, increasing the risk of asset failure and service disruption. Our asset condition data shows declining performance in key fleets such as LV boxes, overhead lines, and substation equipment.

This challenge is not unique to us. The Office of the Auditor-General's 2025 report on electricity distribution businesses identified that "significant additional investment in critical infrastructure will be required if the sector is to maintain reliable electricity supply". Across New Zealand, public energy companies are planning to increase average annual capital investment by 31% from $550 million (2021–2024) to $730 million (2024–2034) in response to these pressures.[2]

Our asset condition assessments, informed by risk-based modelling using CBARM, are identifying critical assets with elevated failure probability and consequence. We are using this data to prioritise our renewal programme and target investment where it will have the greatest impact on network reliability and customer service.

2 Office of the Auditor-General New Zealand. (2025). Energy companies: 2025 review of financial performance and capability. https://oag.parliament.nz/2025/energy-companies/docs/energy-companies.pdf

## AMP assumptions and priorities

This section sets out our planning **assumptions** and strategic **priorities** for the 2026–2036 period. These assumptions reflect our view on how the driving forces identified in section 4 will materialise over time. They form the basis for our investment decisions, shaping how we respond to risk, opportunity, and uncertainty across the network. Our priorities are structured to align with our three-horizon framework and deliver on the strategic shifts outlined in our long-term strategy.

## Our AMP assumptions for 2026-2035W

**1. Electricity demand will grow steadily, driven by industrial decarbonisation and growth, with increasing contributions from electrification and distributed generation**

The principal driver of network demand over the AMP period will be industrial customers progressing with decarbonisation and electrification projects. Industrial customers in Washdyke and Timaru are progressing major electrification and process heat conversion projects as part of national decarbonisation programmes. This is part of the broader structure economic change in South Canterbury.

### South Canterbury's industrial customers

Industrial customers play a central role in shaping electricity demand in South Canterbury because their operations require large and often seasonal loads. Alpine's network has already absorbed significant growth from dairy processing, irrigation, and other major industries, which has reduced spare capacity and influenced how the network is planned and developed. These customers drive peak demand in warmer months and create concentrated pressure around industrial areas such as Timaru, the Port, Redruth, and Washdyke. Their scale and changing energy needs continue to guide decisions about future investment and the resilience of the regional electricity network.

We also anticipate ongoing growth in distributed generation (DG), as more customers install their own generation. Distributed solar uptake has surged, as of mid-2025 there were over 72,000 solar connections in New Zealand (about 3.1% of all electricity customers, a 58% increase since 2023). The resulting increased two-way energy flow and new connections indicate a generally higher utilisation of our network.

Electric vehicle (EV) uptake will continue to rise, contributing to energy demand growth, although material impacts on peak load are expected later in the period as EV penetration reaches higher levels. The market share of battery electric vehicles in New Zealand continues to rise, up to 5.6% in 2025 from 5.0% in 2024.

**2. South Canterbury will experience increasing climate impacts and extreme weather events, with visible effects on our assets and operations**

The South Canterbury region is expected to experience the physical effects of climate change during the AMP planning period, including increased average temperatures, frequent extreme rainfall events, increased high wind events, coastal erosion and inundation in susceptible areas. We also recognise the risk to our network from high wind events, significant flood events, wildfires and significant snow events. The magnified effects of climate change and frequent natural hazard events across New Zealand means it is prudent to assume our assets and business will be negatively impacted.

## Weathering the storm

Unplanned outages in South Canterbury often strike during rough weather, when strong winds, moving vegetation and flying debris damage overhead lines and equipment. These conditions place pressure on the electricity network and can slow restoration efforts during the worst storms. A changing climate is making this challenge more visible each year, with intense weather events testing the resilience of local infrastructure. As conditions grow more unpredictable, the network must work harder to keep households and businesses connected.

These events demonstrate the extreme weather challenges our network will face with increasing regularity.

**Our customers will increasingly require greater autonomy, resilience, choice and transparency, including participation in community energy resilience.**

Customer preferences and expectations will evolve significantly during the AMP period. Customers will seek greater autonomy over their energy systems, including the ability to generate, store, and trade their own electricity. They will require transparency in pricing, service delivery, and network investment decisions. Resilience will become a priority, both for individual households and at the community level, particularly in rural areas where grid redundancy is limited. Communities are seeking to reduce vulnerability to extended outages and climate impacts by installing local solar, battery storage, and microgrids. In regions like Waimate, customers are exploring localised energy solutions, such as solar and community batteries, to address N-1 security concerns and improve supply resilience. By end of 2025, an estimated 217 community resilience sites across New Zealand will have received solar and battery systems funded through the Community Renewable Energy Fund.

Agricultural customers are also reassessing their energy choices, with electrification and distributed generation becoming viable for irrigation, processing, and on-farm operations.

These shifts will influence demand patterns and connection types, and we will need to support them through flexible planning, tailored service models, and transparent engagement.

**Artificial intelligence and automation will present significant opportunities to enhance network operations, productivity, customer service, and resilience.**

Digital technologies, particularly artificial intelligence (AI) and automation, will enable material improvements in how we operate our network, serve customers, and respond to emerging challenges.

The utilities sector is increasingly adopting AI and automation to enhance network operations and improve productivity. These technologies will enable EDBs to shift from manual, resource-intensive processes to smarter, data-driven systems. Traditional asset inspection methods like LiDAR can be replaced with cheaper AI-powered image recognition and condition assessment. Faster adoption of automated probabilistic modelling will reduce planning effort and improve scenario analysis. AI also automates routine business processes, including billing, customer requests, and crew dispatch, improving operational efficiency and freeing staff for strategic work.

We assume that the selective deployment of these technologies will deliver operational efficiencies, uplift service levels, and support productivity gains across both field and office functions.

**Cyber threats to our networks and operations will continue to increase in sophistication and frequency.**

The threat environment for cybersecurity will intensify during the AMP period. Cyberattacks on electricity distribution networks will become more sophisticated, coordinated, and damaging. We assume that robust cybersecurity investment and capabilities will remain essential to protect our network, customer data, and operational continuity.

Globally, the frequency of cyberattacks on utilities have increased in recent years. Threat actors are deliberately targeting control systems, SCADA environments, and supply-side energy networks, with motivations such as financial gain, disruption and leverage.

**Ongoing regulatory reform will increase focus on affordability, efficiency, collaboration, and resilience.**

The regulatory environment for electricity distribution will continue to evolve, with increasing emphasis on affordability, operational efficiency, climate resilience, and sector collaboration.

The Commerce Commission's DPP4 decision, effective from 1 April 2025, sets total forecast net allowable revenue allowances of $382 million for our business in nominal terms over the five-year period. This represents a substantial increase, intended to support network resilience, asset replacement, and the electrification and decentralisation of the energy system. Despite the increase, the DPP4 revenue allowance does not fully reflect the investment requirements to address the scale of the challenges ahead.

The Electricity Authority is progressing distribution connection pricing reform to improve connection pricing methodologies and processes, so they are more efficient and consistent across distributors. The proposed reforms, anticipated to take effect from 1 April 2026, include requirements for distributors to charge only for the minimum scheme for connections, apply standard rates for network capacity costs, implement pioneer schemes to mitigate first-mover disadvantage, and improve transparency through connection charge reconciliations.

The Minister for Energy expects electricity distribution businesses (EDBs) to improve collaboration and efficiency across the sector to support the scale of investment needed for electrification and climate resilience. EDBs must enable faster, fairer connections for rooftop solar and batteries, allowing at least 10kW export per customer barring safety concerns, to empower consumer participation and support system resilience.

## Our AMP priorities and investment themes

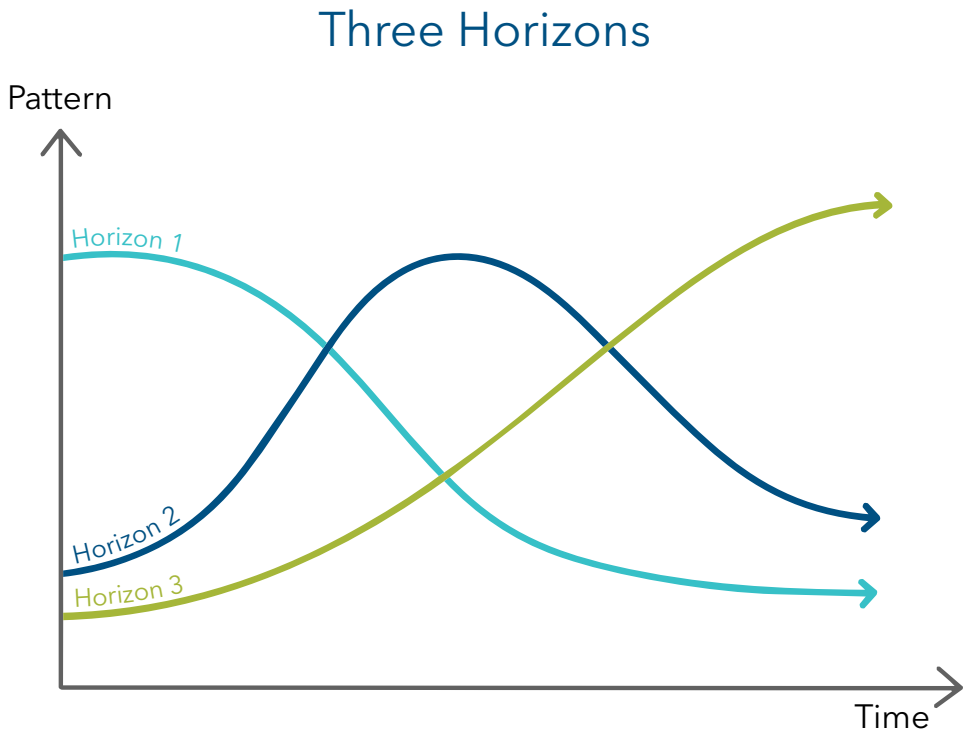
Our AMP priorities are the strategic imperatives that guide our investment decisions over the 10-year planning horizon. These priorities will help us to realise our **big shifts** in section  and are structured to reflect our three-horizon planning framework:

- Horizon 1: Focus on renewing ageing assets, improving service quality and securing supply for growing demand.
- Horizon 2: Expand capacity, enable customer participation and build climate resilience.
- Horizon 3: Lay foundations for a digital, flexible network that supports innovation and adaptive energy use.

The framework maps a shift from the established patterns of Horizon 1 to the emergence of new patterns in Horizon 3, via the transition activity in Horizon 2. We deliver on all three horizons simultaneously but with a varying degree of focus and resources.

Figure 11 below illustrates the degree of focus and level of resources dedicated to each horizon over time.

*Figure 11 | Three Horizons Framework*




Most of the proposed investments in this AMP are focused on Horizons 1 and 2, with a portion allocated to initiatives supporting Horizon 3. We are currently implementing the Horizon 1 Change Plan. The AMP 2026 builds on the Horizon 1 Change Plan and our long-term strategy to ensure our network, systems, and people are ready for this future.

To deliver on these priorities, our investments are organised into three strategic **investment themes**. These themes provide a consistent structure for planning, delivery, and performance tracking across the AMP:

| Theme | Purpose | Expenditure category |
|---|---|---|
| **1. Growth and enablement** | Expand network capacity and enable customer participation and demand flexibility. | Customer connection (CC)<br>System growth (SG) |
| **2. Renewal and resilience** | Maintain and optimise existing assets to ensure reliability, safety, and performance. | Asset replacement and renewal (ARR)<br>Asset relocations (AS)<br>Reliability, safety and environment (RSE)<br>Other reliability, safety, and environment |
| **3. Support and transformation** | Invest in technologies and systems that enable effective asset and network management. | Quality of supply<br>Legislative and regulatory |

Key affordability considerations play a vital role in shaping our investment planning approach. These measures ensure that resources are allocated efficiently and that investments remain financially sustainable and responsive to community needs.

Our affordability measures include:

- **Phased delivery based on scenario triggers:** Our investment programme is structured to respond to demand and risk scenarios, allowing us to phase delivery in line with confirmed customer needs and system constraints. This approach ensures that capital is deployed where and when it delivers the greatest value, while deferring discretionary spend until it is justified by load growth, resilience requirements, or regulatory change.
- **Prioritised investment linked to customer value:** Our investment decisions are guided by a risk-based framework that aligns with the Commerce Commission's expectations for transparency and long-term outcomes. We prioritise projects that maintain service quality, support decarbonisation, and deliver measurable benefits to customers, ensuring that every dollar spent contributes to reliability, resilience, or strategic enablement.
- **Independent assurance to validate our investment assumptions:** To ensure our forecasts are robust and credible, we engage independent assurance to review key assumptions, including demand growth, cost escalations, and delivery feasibility. This process supports confidence in our planning and helps us demonstrate value-for-money to stakeholders, regulators, and shareholders.
- **Flexibility to defer or reshape expenditure:** We are actively working with EECA and other partners to explore non-network options that reduce cost and improve efficiency. This includes trials of demand-side management, distributed energy resources, and flexible services that can defer or avoid capital investment.
- **Collaboration with the sector to share cost and capability:** We are deepening collaboration with other EDBs, Transpower, and industry bodies to co-invest in shared platforms, data tools, and resilience initiatives. These partnerships help reduce duplication, spread costs, and accelerate innovation, contributing to long-term affordability.

Our six AMP priorities are outlined below. For each priority, we describe the rationale, the horizon where action is most needed, and the material projects that will deliver on it. A project is treated as material when its cost is above $500k, when it concerns a critical asset, or when deferring it would introduce an unacceptable risk to customer supply.

## 1. Mature asset management and network operations (Horizon 1)

Robust asset management and operational excellence are the foundation of our long-term success and a key part of our shift towards smart infrastructure. Strengthening our asset management maturity and operational capability is essential. By embedding strong lifecycle stewardship, data quality, and planning discipline, we ensure our business-as-usual operations remain reliable and efficient, while also preparing for future transformation.

This focus on foundational capabilities is central to Horizon 1, where immediate uplift in operational performance supports both current needs and future ambitions.

*Table 2: Investments strengthening asset management maturity within Horizon 1*

| Project | Description | Cost ($'000) | Year |
|---|---|---|---|
| **Grasmere sub transmission upgrade** | The Grasmere sub transmission upgrade forms reflects our need to reinforce supply into this area as demand patterns evolve. The work focuses on strengthening the sub transmission elements that support the site so that capacity, reliability, and operational flexibility are maintained over the long term. | 9,200 | FY27-FY30 |
| **Routine Maintenance Defect Resolution** | Maintenance teams address defects before they escalate and stabilise asset condition. | 900 | Annual |
| **Urgent Overhead Line Response** | Red tagged poles and emergent faults are addressed quickly to protect public safety and avoid sudden outages. | 1020 | Annual |
| **RMUs Attending Sub-Transmission Circuits** | Installing new RMUs on the Grasmere to Hunt Street sub-transmission circuits will address capacity constraints and improve security of supply. | 500 | FY27 |
| **Reducing the Risk posed by Load Break Switch Flashovers** | Replacing high risk Load Break Switches will reduce flashover risk and improve network safety and reliability. | 600 | FY27, FY28 |
| **Facilitate Solar Farms** | Installing HV connections and supporting infrastructure will facilitate solar farm generation and accommodate new export capacity. | 2,750 | FY27 - FY28, FY30 - FY31 |

## 2. Renew for reliability and service quality (Horizon 1)

Maintaining network reliability and service quality is a pressing challenge as our asset fleets age, climate change impacts become more severe, and customer expectations for affordability and performance remain high. Immediate action is required to address declining asset condition and comply with DPP4 quality standards. By prioritising timely renewal and targeted investment, we can prevent service disruptions, uphold regulatory requirements, and ensure the network remains fit-for-purpose as our environment evolves.

This priority is at the heart of Horizon 1, where sustaining reliability is critical to meeting both current and emerging needs.

*Table 3: Investments renewing reliability within Horizon 1*

| Project | Description | Cost ($'000) | Year |
|---|---|---|---|
| **Timaru Pages Road to Centennial Park Connection** | Removing overhead lines and completing undergrounding reduces outage exposure and improves long-term reliability. | 1,500 | FY27, FY28 |
| **Geraldine Feeder Upgrade** | Upgrading the GLD Geraldine 191 feeder conductor resolves forecast breaches and secures long-term supply capacity for the Geraldine area. | 1,200 | FY28 - FY29 |
| **Grants Road Timaru Feeder Capacity Increase** | Replacing the existing backbone cable with a higher rated asset removes a developing constraint and supports reliable service through the decade. | 1,220 | FY30 - FY31 |
| **Hunt Street Timaru Switching Station Rebuild** | Rebuilding the station with modern switchgear strengthens capacity, improves switching performance, and supports ongoing urban expansion. | 6,000 | FY32 - FY33 |

## 3. Secure capacity for growing demand (Horizon 2)

As South Canterbury experiences industrial electrification, population growth, and the rise of distributed energy resources, our network must adapt to new and evolving demand patterns. Addressing capacity constraints and enabling flexible, scalable infrastructure are essential to support industrial projects, housing intensification, and the integration of EVs and DERs.

Security of supply is an increasing concern in parts of our network, particularly where GXP capacity is nearing its limits. In these areas, targeted investment is required to maintain reliability, support industrial growth, and ensure the network can meet future demand without compromising service quality.

This priority sits within Horizon 2, where investment bridges current operations and future requirements, ensuring the network can respond dynamically to growth and change.

*Table 4: Investments securing capacity within Horizon 2*

| Project | Description | Cost ($'000) | Year |
|---|---|---|---|
| **Temuka Feeder Capacity Upgrade** | Replacing constrained underground cables removes overload risk and prevents repeat failures as demand grows. | 600 | FY27 |
| **Timaru GXP Feeder Reconfiguration** | Shifting feeders from 11kV to 33kV removes emerging constraints and increases efficiency at the Timaru GXP. | 2,200 | FY30, FY34 |
| **TMK Temuka Security of Supply Improvements** | Strengthening supply through transformer upgrades or load shifting restores N 1 security and supports future industrial demand at TMK. | 3,500 | FY33–FY36 |
| **Studholme Ripple Plant Upgrade** | Upgrading the STU Ripple Plant will replace end of life equipment and align with Transpower's transformer upgrades. | 1,100 | FY28 |
| **Second Pleasant Point Transformer** | Installing a second power transformer at PLP will improve security of supply and network resilience. | 1,700 | FY31 |
| **Rebuilding Tekapo Zone Substation** | Rebuilding the Tekapo zone substation with new switchgear and overhead connection equipment will improve network capacity and reliability. | 2,500 | FY32 |
| **Replace poor condition transformer** | Replacing the power transformer at Pleasant Point will mitigate its failure risk and reduce the risk of environmental contamination. | 1,500 | FY32 |
| **Replace Fairlie Power Transformer.** | Replacing the Fairlie power transformer will address ageing asset risk and maintain network reliability. | 1,500 | FY32 |
| **Timaru Airport Electrification Cabling** | Installing cabling for airport electrification at Timaru Airport will support the Timaru Airport Project. | 5,000 | FY32 |
| **Upgrade Tekapo GXP** | Upgrading the TKA GXP protection scheme and transformer capacity will remove limiting network constraints. | 3,000 | FY33 |
| **Timaru GXP Feeder Reconfiguration** | Reconfiguring the Timaru GXP feeders from 11 kV to 33 kV | 1,000 | FY34 |
| **Mitigating Tekapo Outages** | Installing a second sub-transmission circuit for Tekapo will improve security of supply and reduce outage risk. | 3,000 | FY36 |

## 4. Strengthen climate and weather resilience (Horizon 2)

Asset deterioration and hazard exposure require us to embed resilience into immediate upgrades and long-term planning. Improved climate resilience also means making informed decisions as to where we locate assets in the future, and deciding whether we even build or rebuild assets at all.

Horizon 2 is where we will strengthen the network's ability to absorb and recover from future climate impacts and embed long-term resilience into network design, planning systems, and asset strategies ensuring the network remains adaptive and reliable under future climate conditions.

*Table 5: Investments strengthen climate resilience*

| Project | Description | Cost ($'000) | Year |
|---|---|---|---|
| **Fairlie LV Undergrounding** | Undergrounding, or rebuilding, low voltage lines removes exposure to wind and snow events while reducing maintenance and outage frequency. | 1,050 | FY27, FY28 |
| **Pukaki Downs Line Renewal** | Renewing this long rural route strengthens weather resilience on a corridor exposed to wind, snow and flooding impacts. | 1,200 | FY31 |
| **Underground Substation Relocation Programme** | Moving the TE1 and TE77 substations above ground improves resilience, access and long-term reliability for critical services. | 5815 | FY27 – FY34 |
| **Timaru GXP Ripple Plant Replacement** | Replacing the ageing ripple plant improves signalling reliability and supports stable operation during climate driven disturbances. | 1,500 | FY31 |
| **TMK Temuka Security of Supply Improvements** | Strengthening N - 1 security improves the network's ability to withstand equipment failure and maintain supply during severe weather events. | 3,500 | FY28–FY31 |
| **Tekapo Bridge Cable Crossing** | Upgrading the Tekapo Bridge cable crossing will improve resilience. | 3,600 | FY29, FY31 - FY32 |

## 5. Meet evolving customer needs for flexibility and participation (Horizons 2 & 3)

Customer expectations are shifting rapidly, with greater demand for visibility, choice, and personalised energy services. The growth of distributed energy resources, flexible energy solutions, and ongoing pricing reform are reshaping how the network must operate. To empower customers and support fairness and sustainability, we need to develop new capabilities and engagement platforms.

This priority aligns with our shift to enable customer choice and is central to Horizon 2, where enabling flexibility and participation ensures the network delivers value now and into the future. It also aligns with Horizon 3, where we build the digital capabilities and service models needed to support customer-led energy use and dynamic participation.

*Table 6: Enabling flexibility, participation, and future energy choices*

| Project | Description | Cost ($'000) | Year |
|---|---|---|---|
| Growth Driven Cable Capacity Upgrade | Increasing cable sizes in developing areas maintains voltage stability during peak periods and ensures the network can absorb steady load growth without constraint. | 5,070 | FY30-FY36 |
| Timaru Port Sub Transmission Ducting | Installing new ducting along key Timaru Port routes prepares the area for higher capacity sub transmission supply and avoids future disruption. | 1,000 | FY34 |
| Washdyke Cable Upgrade Provisions | Strengthening cable capacity and configuration in the Washdyke area supports resilience as the industrial load grows and hazard exposure increases. | 990 | Annual |
| Rebuild Pleasant Point Substation | Rebuilding substation PLP will improve asset condition, capacity, and network reliability. | 7,000 | FY32 – FY33 |
| Convert North Street Substation to 33kV | Converting North Street Substation to 33kV will increase capacity. | 16,000 | FY33 – FY36 |
| Establish a second Tekapo substation | Establishing a second zone substation in Tekapo will improve security from N to N-1. | 7,000 | FY33 - FY34 |
| Twizel Sub N-1 constraint | Upgrading the Twizel substation with two new transformers will address its forecast capacity constraint. | 2,000 | FY33 – FY36 |
| Build new switching substation | Building a new West Washdyke substation will support new loads in North-Washdyke. | 15,000 | FY34 – FY36 |
| Build new Washdyke 33kV Substation | Building a new 33 kV substation at Washdyke will meet future load growth. | 9,500 | FY34 – FY36 |
| New Port Switching Station | Building a new Port Switching Station at Timaru Port will resolve capacity constraints. | 6,000 | FY34 – FY36 |
| Tekapo GXP security. | Increasing security at TKA GXP from the 11kV bus will improve resilience and provide permanent backup supply. | 1,500 | FY34 – FY36 |
| Improving Twizel Substation Security of Supply | Installing a second supply circuit breaker at Twizel Substation will improve security of supply. | 6,000 | FY35 – FY36 |
| Install second sub-transmission circuit cable between to Twizel substation | Installing a second sub-transmission circuit cable from Twizel GXP to its substation will improve capacity. | 3,000 | FY35 – FY36 |
| Install supply cable from North Street Substation and new switching substation. | Installing a cable between North Street Substation and the new switching substation will support the New Switching Substation project. | 1,600 | FY35 – FY36 |
| Port Distribution Feeder Upgrades | Upgrading distribution feeders for the Port Switching Station will improve its security of supply. | 4,200 | FY35 – FY36 |

## 6. Lay the foundations for a digital, flexible future (Horizon 3)

The energy sector is undergoing a digital transformation, with automation, predictive analytics, and smart technologies redefining what's possible. In alignment with our shift towards smart infrastructure and to position us for future operating models, we must invest, largely as operational expenditure, in digital capabilities and cybersecurity, building the systems and culture needed for long-term flexibility and innovation.

This is the focus of Horizon 3, where preparing for a digital future ensures we remains adaptive and resilient as technology and customer needs continue to evolve.

*Table 7: Building the digital capabilities needed for a flexible future*

| Project | Description | Cost ($'000) | Timing |
|---|---|---|---|
| Cyber Security Programme | Risk based uplift that protects critical infrastructure, strengthens resilience and ensures compliance with emerging cyber security obligations. | 700 | Annual |
| ERP EAM implementation and Operating Model transformation | Creates Alpine's digital backbone, modernising processes and enabling a flexible future operating model using Microsoft Dynamics 365 Finance and Operations. | 8,500 | FY27, FY28 |

Table 8 summarises the material projects that support each AMP priority, grouped by our three strategic investment themes. This illustrates how our investment programme is structured to deliver on our strategic outcomes across Horizons 1, 2 and 3.

*Table 8 | Summary of material projects by investment theme*

| Investment Theme | Project | Year | Cost ($'000) |
|---|---|---|---|
| Strengthening Asset Management Maturity | Grasmere sub transmission upgrade | FY27-FY30 | 9,200 |
| | Routine Maintenance Defect Resolution | Annual | 900 |
| | Urgent Overhead Line Response | Annual | 1020 |
| | RMUs Attending Sub-Transmission Circuits | FY27 | 500 |
| | Reducing the Risk posed by Load Break Switch Flashovers | FY27, FY28 | 600 |
| | Facilitate Solar Farms | FY27 - FY28, FY30 - FY31 | 2,750 |
| Renewing Reliability | Timaru Pages Road to Centennial Park Connection | FY27 - FY28 | 1,500 |
| | Temuka East Asset Renewal | FY27 | 855 |
| | Geraldine Feeder Upgrade | FY28 - FY29 | 1,200 |
| | Grants Road Timaru Feeder Capacity Increase | FY30 - FY31 | 1,220 |
| | Hunt Street Timaru Switching Station Rebuild | FY32 - FY33 | 6,000 |
| Securing Capacity | Temuka Feeder Capacity Upgrade | FY27 | 600 |
| | Timaru GXP Feeder Reconfiguration | FY30, FY34 | 2,200 |
| | TMK Temuka Security of Supply Improvements | FY33–FY36 | 3,500 |
| | Studholme Ripple Plant Upgrade | FY28 | 1,100 |
| | Second Pleasant Point Transformer | FY31 | 1,700 |
| | Rebuilding Tekapo Zone Substation | FY32 | 2,500 |
| | Replace poor condition transformer | FY32 | 1,500 |
| | Replace Fairlie Power Transformer. | FY32 | 1,500 |
| | Timaru Airport Electrification Cabling | FY32 | 5,000 |
| | Upgrade Tekapo GXP | FY33 | 3,000 |
| | Timaru GXP Feeder Reconfiguration | FY34 | 1,000 |
| | Mitigating Tekapo Outages | FY36 | 3,000 |

| | | | |
|---|---|---|---|
| Strengthen Climate Resilience | Fairlie LV Undergrounding | FY27, FY28 | 1,050 |
| | Pukaki Downs Line Renewal | FY31 | 1,200 |
| | Underground Substation Relocation Programme | FY27 – FY34 | 5815 |
| | Timaru GXP Ripple Plant Replacement | FY31 | 1,500 |
| | TMK Temuka Security of Supply Improvements | FY28–FY31 | 3,500 |
| | Tekapo Bridge Cable Crossing | FY29, FY31 - FY32 | 3,600 |
| Enabling Participation | Growth Driven Cable Capacity Upgrade | FY30-FY36 | 5,070 |
| | Timaru Port Sub Transmission Ducting | FY34 | 1,000 |
| | Washdyke Cable Upgrade Provisions | Annual | 990 |
| | Rebuild Pleasant Point Substation | FY32 – FY33 | 7,000 |
| | Convert North Street Substation to 33kV | FY33 – FY36 | 16,000 |
| | Establish a second Tekapo substation | FY33 - FY34 | 7,000 |
| | Twizel Sub N-1 constraint | FY33 – FY36 | 2,000 |
| | Build new switching substation | FY34 – FY36 | 15,000 |
| | Build new Washdyke 33kV Substation | FY34 – FY36 | 9,500 |
| | New Port Switching Station | FY34 – FY36 | 6,000 |
| | Tekapo GXP security. | FY34 – FY36 | 1,500 |
| | Improving Twizel Substation Security of Supply | FY35 – FY36 | 6,000 |
| | Install second sub-transmission circuit cable between to Twizel substation | FY35 – FY36 | 3,000 |
| | Install supply cable from North Street Substation and new switching substation. | FY35 – FY36 | 1,600 |
| | Port Distribution Feeder Upgrades | FY35 – FY36 | 4,200 |
| Building Digital Capabilities | Cyber Security Programme | Annual | 700 |
| | ERP EAM implementation and Operating Model transformation | FY27, FY28 | 8,500 |
| | | **Total** | **164,070** |

## 4.3. AMP foundations

Delivering on our AMP priorities requires more than investment alone. It depends on the systems, capabilities, and practices that enable effective asset management and network delivery. These foundations are grouped into three categories:

### Mature asset and network management

#### Lifecycle stewardship

Our internal reviews and fleet strategy development continue to strengthen lifecycle stewardship by ensuring that planning considers each asset from its initial need through to eventual disposal. This reflects a growing shift toward whole of lifecycle thinking across our fleets. While these foundations are in place, adoption remains uneven, with some workflows fragmented and transitions between planning, delivery and operations not yet structured consistently. To support more reliable lifecycle planning and delivery we are introducing a new Asset Management Guide that will clarify governance, strengthen role expectations and provide structured training across teams.

The recent external review by CutlerMerz observed that project documentation and supporting evidence vary in depth and consistency, particularly in the way asset condition, risk and cost information are recorded and applied. They recommended improvements that would strengthen

lifecycle discipline, including the development of a structured historical cost database, clearer and more transparent defect and likelihood assessments, and better differentiation between minor defects and issues that materially influence risk. CutlerMerz also highlighted the need for a clearer line of sight between asset lifecycle requirements and the maintenance or renewal activities that address those risks. These insights reinforce the need to improve traceability across planning assumptions and to embed consistent lifecycle reasoning in our decision making.

In response, we are incorporating these recommendations into a broader Asset Mastery Programme that will sit alongside the Asset Management Guide. This programme will establish a structured historical cost database and standard unit rates, refine defect categorisation and likelihood rules, and define clearer intervention strategies for each fleet so that condition and risk information flow consistently into planning, works prioritisation and delivery. As our new enterprise resource planning and enterprise asset management systems are implemented, these improvements will be integrated into common processes and tools, creating a more transparent and repeatable lifecycle pathway for each asset class. This will strengthen our lifecycle stewardship, support a more stable and defensible works programme and provide a stronger basis for future regulatory engagement on the prudency and efficiency of our investment plans.

### Data driven asset management

Our asset health models, including CBARM, now inform a growing proportion of investment decisions, and early integration of smart meter and SCADA data is beginning to support more evidence-based planning. Data quality and accessibility still vary across fleets, and in some areas, staff maintain parallel records due to limitations in existing systems. Ongoing work to cleanse and consolidate asset data, together with the implementation of a modern ERP and EAM system that will integrate GIS, SCADA and CRM platforms, will provide a stronger foundation for analytics, forecasting and lifecycle management.

CutlerMerz observed that clearer supporting evidence and more consistent cost estimation would strengthen project justification. We are embedding their recommendations within an Asset Mastery Programme that will create a structured historical cost database, standardise cost and quantity assumptions, refine the inputs and outputs of asset health and risk models, and introduce simple economic tools such as Expected Unserved Energy into option assessment. As the new ERP and EAM systems are implemented these improvements will be built into common processes and data models, bringing together operational and customer information and improving confidence in future investment decisions.

### Standardisation and continuous improvement

Technical standards exist for planning, maintenance, and construction, although adherence is inconsistent and documentation maturity remains mixed. Our previous AMMAT score of 1.97 reflected these gaps and emphasised the need for stronger integration and continuous improvement discipline. We are responding through the development of standard network designs, Bills of Materials, enhanced Safety in Design processes, and formalised design governance. These actions aim to improve delivery consistency, reduce cost, and enhance safety outcomes.

The CutlerMerz review reinforced the value of a more standardised and repeatable planning environment. They suggested supplementing our SAIDI based prioritisation with a basic Expected Unserved Energy metric and introducing an automatic adjustment mechanism for provisional renewal allowances as projects change. These recommendations support a more consistent and evidence-based approach to investment planning.

In response, we are embedding these improvements within an Asset Mastery Programme that will align our technical standards, planning tools and digital platforms. As our new enterprise systems are implemented, standard designs, Bills of Materials and governance processes will be built into everyday workflows, with feedback loops to capture lessons from delivery. This will lift our AMMAT performance over time, strengthen continuous improvement discipline and provide a more transparent and repeatable basis for demonstrating the prudency and efficiency of our investment plans.

### Resilience and climate adaptation

Resilience is an increasingly visible part of our planning, supported by hazard information from Earth Science New Zealand and climate risk models that continue to evolve. These inputs have improved our understanding of network vulnerability and exposure. Our score under the Resilience Maturity Model Assessment Tool (RMMAT), which provides a structured assessment of organisational readiness in resilience planning, shows that maturity remains in a developing state and requires deeper integration across planning and investment decisions. Our Resilience Strategy seeks to embed resilience principles throughout the asset lifecycle by informing renewal choices, improving scenario analysis, and guiding the development of design standards that reflect changing hazard conditions.

CutlerMerz considered these resilience drivers within a longer-term planning horizon. They highlighted the importance of recognising the scale of renewal activity that will emerge as the large cohort of assets installed during the expansion period of the 1960s and 1970s approaches the end of its service life. They advised that delivery capability will need to grow in step with this workload to ensure that our renewal and resilience commitments remain achievable. Their review also noted a noticeable increase in renewal and resilience related expenditure and cautioned that some future resilience needs may be understated because they are not yet being assessed through a structured and evidence-based approach. These insights, when read alongside our resilience objectives, reinforce the need for deliberate long-term planning, stronger modelling, and a sustained focus on ensuring that delivery capacity aligns with the scale and timing of future resilience and renewal investment.

In response, we are using the RMMAT tool to shape a long-term renewal and resilience pathway that sequences uplifted renewals, resilience projects, and associated growth works over successive regulatory periods. We are strengthening resilience intelligence by integrating hazard and climate models into our risk and planning tools, and by expanding scenario analysis to test different combinations of renewal timing, extreme weather events, and recovery effort. At the same time, we are building delivery capacity through our Horizon 1 transformation and evolving delivery model so that increased renewal and weather related rebuild activity can be delivered safely and efficiently. As our data, models, and systems mature, we will apply more structured resilience assessments when scoping projects, refine how resilience driven expenditure is prioritised, and ensure that emerging climate and hazard risks are reflected transparently in our long-term works programme and in future engagement with regulators and stakeholders.

## Deliverability, including enhanced productivity and collaboration

### Delivery model

**Current state:** We have strengthened our delivery capability by operating with an integrated field delivery model, a cross-functional team that combines various field operations, engineering, planning, and support disciplines under one structure. This offers several significant benefits. This shift has enabled us to directly deliver a greater share of our works programme, improving responsiveness and accountability across capital, maintenance, and customer-initiated projects.

**Improvement:** As we deliver more of our works programme internally, we are transitioning to a preferred supplier model for externally delivered work types. This will improve cost certainty, delivery speed, and consistency of outcomes. Supported by clearer commercial frameworks and improved procurement coordination, this model ensures flexibility while maintaining high standards of safety and performance.

### Productivity

**Current state:** Our delivery and operational processes have historically been fragmented, with duplicated systems and manual workflows limiting efficiency. We are now focused on lifting productivity across the full network delivery value chain, from planning and design through to execution and performance tracking, and in our network operations.

**Improvement:** We are implementing lean practices and digitising delivery workflows to reduce rework and improve coordination. Key initiatives include standardising designs and materials, streamlining scheduling and supply chain processes, and deploying integrated platforms such as AdaptiveWork, ERP, and GIS. These changes will enable smarter decision-making and measurable efficiency gains across both network delivery and operations.

### Collaborative delivery to enable system change

**Current state:** We recognise that the scale and complexity of the transformation required, driven by electrification, affordability pressures, and workforce constraints which cannot be met by any one EDB in isolation. The Minister for Energy has set expectations for collaboration between EDBs and with the sector. Broader sector collaboration remains at formative stage: there are early signs of progress, but efforts to date have largely been ad hoc, small-scale, or regionally fragmented.

**Improvement:** We are actively shifting from ad hoc coordination to intentional, at-scale collaboration to deliver the system change required. Our approach focuses on formalising partnerships, sharing capability, and creating consistent delivery models across the South Island. This approach supports Government expectations around performance, affordability, and regional investment efficiency and is essential to delivering a resilient, flexible network that can meet future demand.

## Robust risk management

### Risk based decision making

In their review, CutlerMerz noted that our risk based approach is generally proportionate for a network of our size, with support tools providing strong locational insight and supporting renewal decisions. They also observed that while risk concepts appear across planning and governance activities, the underlying methods are applied unevenly, and some asset classes lack consistent documentation. This limits the clarity and traceability of how condition information and likelihood judgements progress to investment decisions.

CutlerMerz recommended a more deliberate and structured connection between asset condition, lifecycle risk, and the activities that manage those risks. This requires clearer documentation of how risks evolve over an asset's life and how inspection findings influence maintenance, renewal, and sequencing decisions. In response, we are strengthening our risk governance so that lifecycle risks are consistently reflected in our inspection programmes, operational practices, and long-term planning.

We are embedding structured risk processes into investment prioritisation and the development of the works programme so that decisions follow a transparent logic that links condition, consequence, and value. CutlerMerz also highlighted the need for stronger organisational capability to support risk informed decision making. We are therefore developing resilience intelligence tools that bring together asset data, scenario modelling, and operational insight. These improvements will support a more consistent application of risk principles across the business and allow our risk processes to mature in a way that strengthens long-term network stewardship.

# 5. Asset management approach

Alpine Energy's asset management approach ensures we deliver safe, reliable, and affordable electricity to South Canterbury while preparing for a future shaped by electrification, climate change, and evolving customer expectations.

This chapter outlines how we manage our assets across their lifecycle, from planning and design through to operation, maintenance, and renewal, guided by customer needs, asset conditions, and long-term strategic priorities. It describes our shift from reactive practices to structured, risk-based asset management, supported by improved data, governance, and delivery capability, and sets out the principles, processes, and systems that will enable growth, resilience, and sustainability.

## Links to our strategy

Our asset management directly supports our long-term strategy. By integrating customer needs, business priorities, and resource availability, we ensure that our asset management activities directly support the delivery of our Asset Management Plan.

This asset management approach enables us to maximise asset value while facilitating a secure, reliable, and sustainable electricity supply. It underpins our ability to provide energy choices that are informed, accessible, and resilient.

Our asset management planning is directly aligned with our strategic pillars: thriving communities, electricity for all, resilient and reliable electricity, and financial sustainability. Through disciplined planning and prioritisation, we ensure that the management of our assets remains future-focused, customer-driven, and grounded in our commitment to sustainability and responsible stewardship.

This section outlines:

- 5.1 A summary of our asset management approach including our asset management framework, governance and organisation responsibilities and asset lifecycle decision-making processes.
- 5.2 Our plans to further mature our asset management approach.

## Current asset management approach

Delivering a safe, reliable, and efficient electricity supply to our community, while adapting to a dynamic operating environment, requires robust asset management systems and practices. Our approach to asset management is built to respond to evolving customer needs, climate pressures, and emerging risks, while ensuring that we continue to deliver value and maintain trust.

We recognise that strong asset management capability enables innovation and provides the foundation for shaping our future. As our environment changes, so too does our approach to managing the lifecycle of our assets, with continuous improvement embedded in our decision-making processes.

An independent review by CutlerMerz has provided further insight into the maturity of our current practices. Their assessment has informed improvements build a disciplined and evidence-based asset management system. CutlerMerz highlighted that several of our asset management practices would benefit from greater structure, clearer documentation, and more consistent application across fleets. Their review noted that some inputs driving risk assessments, particularly likelihood values and defect treatment thresholds, are not always linked to historic failure rates or quantitative evidence, which in turn affects the transparency of our decision making. They also observed that our forecasting and prioritisation processes could be strengthened through more standardised costing, improved treatment of provisional allowances, and clearer integration of emerging risks into medium and long-term planning. These findings reinforce the need to mature our systems, improve the traceability of assumptions, and embed more robust lifecycle and risk governance across our planning processes.

Guided by these insights, we will investigate evidence-based project pathways that support prudency, incorporate economic value modelling, develop a consolidated and transparent prioritisation framework, and explicitly consider the increased risk of outages and future backlog when work is deferred. Together these steps will help ensure that our planning and investment decisions enable communities and customers to continue to benefit from reliable, efficient and compliant infrastructure.

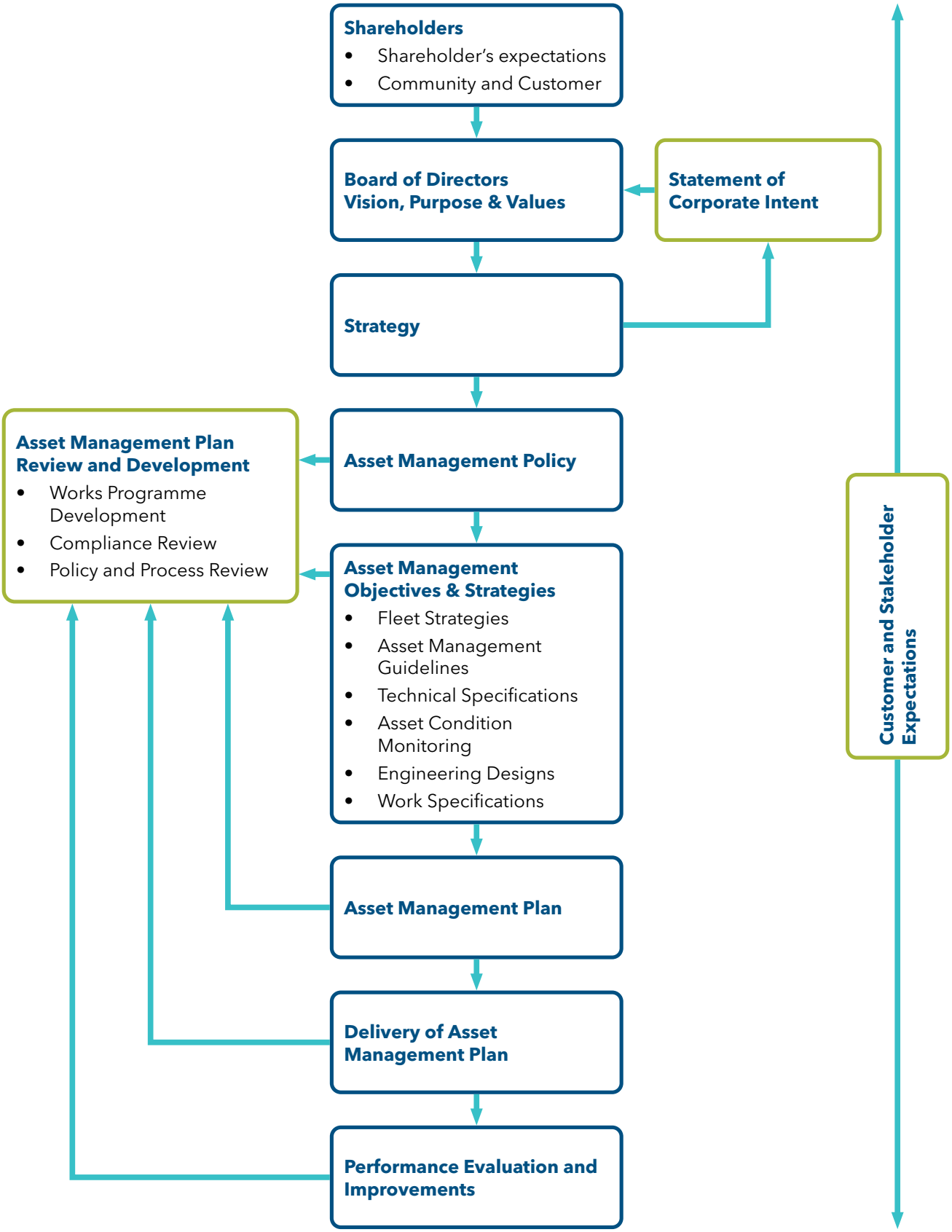
## Asset Management Framework

Our Asset Management Framework (AMF) provides the structure through which we align our asset management practices with international best practice, including ISO 55000, ISO 55001, and ISO 55002. The AMF defines the key layers of governance, strategy, planning, and delivery, and establishes a clear line of sight from shareholder expectations to operational execution.

The framework ensures that each level of activity contributes meaningfully to our strategic direction and asset management objectives. It integrates our vision, values, and strategic goals with the policies, plans, and processes that guide how we manage our assets across their full lifecycle.

The framework also supports continuous improvement by linking performance evaluation and compliance review with future planning cycles. Figure 12 illustrates how these elements interact to form a coherent system that supports effective decision-making and sustainable outcomes.

*Figure 12 | Asset Management Framework*



## Asset Management Policy

Our Asset Management Policy provides the foundation for how we plan, design, operate, and maintain our distribution network to deliver a safe, reliable, and efficient electricity service. It aligns our asset management practices with our vision, purpose, values, and strategic pillars, and affirms our commitment to service delivery that meets the expectations of our customers, stakeholders, and regulators.

- Placing safety first in all asset-related activities, with a strong focus on achieving zero harm for our employees, contractors, and the public.
- Engaging meaningfully with our community and stakeholders on asset matters that impact them.
- Complying fully with all applicable laws, regulations, and codes of practice in our asset management activities.
- Delivering a reliable and efficient distribution network that supports customer expectations, environmental sustainability, and New Zealand's decarbonisation goals.
- Managing network performance to achieve target service levels across safety, reliability, and resilience.
- Evaluating cost and risk to ensure our investments and interventions maximise long-term asset value.
- Making informed and timely decisions across investment, maintenance, operations, and renewals, in line with delegated authority.
- Building capability to integrate non-network alternatives and demand-side solutions into our planning and investment decisions.
- Developing our organisational structure and workforce to ensure the right mix of skills and experience to deliver on our asset management objectives.
- Continuously improving our asset management systems to enable data-driven, value-optimised decisions.

Our Asset Management Policy is enacted through the Asset Management Objectives & Strategies and the Asset Management Plan, which together ensure our approach remains effective, aligned, and forward-looking.

## Asset management objectives & strategies

Our asset management objectives translate the intent of our Asset Management Policy into actionable priorities that guide how we manage our network. These objectives are aligned with our strategic pillars and respond to our operating context, stakeholder expectations, and regulatory obligations. We are committed to:

- Providing a safe electricity delivery service, with health and safety as our foremost priority. This reflects our Statement of Corporate Intent and the foundational importance of 'zero harm' to our people, contractors, and the public.
- Maintaining and improving service levels that reflect customer expectations for security, reliability, and resilience. We aim to deliver service quality that is both acceptable and affordable, while ensuring compliance with regulatory standards. This includes assessing and enhancing our network's ability to withstand the impacts of climate change and extreme weather.
- Delivering cost-effective performance, by managing our capital and operational expenditure within budget while maintaining focus on efficiency and value.
- Supporting economic growth across South Canterbury, through the delivery of infrastructure and services that meet the evolving energy needs of our region. We will continue to actively engage with our communities as we plan, build, and operate our assets.

- Embedding sustainability in decision-making, by integrating Environmental, Social, and Governance (ESG) considerations across all aspects of our asset management practice. This includes reducing our carbon footprint, enabling distributed energy resources, and supporting our stakeholders in their decarbonisation goals.
- Lifting our asset management maturity, by aligning more closely with ISO 55000 and improving our AMMAT scores as reported to the Commerce Commission. We are committed to building capability and embedding best practice across our people, systems, and processes to support long-term strategic outcomes.

Supporting these asset management objectives are key strategies and tools, including fleet strategies, planning processes, and technical specifications. Together, these guide how we assess asset condition, design engineering solutions, specify work standards, and prioritise investment.

Our policies and strategies are listed below in Table 9 with a description on how these interact with our asset management process.

*Table 9 | Policies and strategies*

| Document | How it impacts our asset management |
|---|---|
| **Risk Management Policy** | Guides how we identify, assess, and manage risk across all asset-related activities. It ensures that network and investment risks are evaluated within defined tolerance levels and managed using ISO 31000:2018 principles to support informed, value-based decisions. |
| **Delegation of Authority Policy** | Defines the framework under which authority is delegated to ensure responsible decision-making across asset management. It provides governance for all expenditure and risk-related decisions, ensuring they are made in line with approved delegations. |
| **Health and Safety Policy** | Establishes the safety standards that apply to all asset management activities. It ensures our projects, maintenance, and operations protect the health and safety of staff, contractors, and the public, from design through to delivery. |
| **Lifecycle Strategies** | Operationalise our Asset Management Policy and Strategy by applying lifecycle principles to planning, maintenance, and renewal. These strategies ensure our asset decisions are consistent with long-term performance and value objectives. |
| **Fleet Strategies** | Translate the intent of our Asset Management Policy and Strategy into practical, asset-specific approaches. They define how we manage risk, performance, and lifecycle activities across each asset class, ensuring our decisions reflect the unique condition, criticality, and operational role of each fleet. These strategies provide the foundation for consistent planning, maintenance, and renewal practices across the network. |

Our standards support our Asset Management Framework by ensuring consistent practices across planning, construction, operation, and maintenance, as listed below in Table 10. As we continue to strengthen our alignment with ISO 55000, the application and development of standards remain a key focus area in advancing our asset management maturity.

*Table 10 | Standards*

| Document | How it impacts our asset management |
|---|---|
| **Planning Standards** | Establish a uniform approach to the planning, design, and maintenance of our electrical distribution assets, ensuring operations align with safety, reliability, efficiency, and strategic 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** | Outline design principles and construction practices to ensure new assets are built to required performance and safety standards. |
| **Technical Specifications** | Detail the components, materials, and workmanship standards expected from our service providers in support of consistent asset performance. |
| **AS/NZ Standards** | Establish standards for the electrical industry in Australia and New Zealand, including standards for safety, quality, and performance. |

## Asset Management Plan

This Asset Management Plan (AMP) will be the central mechanism through which we deliver a safe, reliable, and efficient electricity supply that meets the needs of our customers and adapts to the changing environment in which we operate. It supports effective decision-making by integrating our asset management systems with strategic, operational, and financial planning.

The AMP serves as a forward-looking roadmap that combines customer needs, capacity planning, lifecycle management, and risk-based prioritisation. It draws from our Asset Management Policy, Framework, Objectives, and fleet strategies to establish a clear line-of-sight between day-to-day activities and long-term strategic outcomes. The AMP outlines the principles that guide our asset management approach and provides the structure for how we respond to evolving expectations across service delivery, cost efficiency, environmental sustainability, and stakeholder engagement.

By aligning our asset planning with business priorities and regulatory obligations, the AMP ensures we remain focused on continuous improvement while maintaining confidence in our stewardship of critical infrastructure.

## Asset management sustainability framework

Sustainability is a core consideration in our asset management planning and investment decisions. Through this AMP, we are strengthening our focus on the performance of an asset across its lifecycle by embedding sustainable design, procurement, and operational practices into our systems and processes.

As part of our evolving approach, we are exploring opportunities to reduce emissions, limit environmental impacts, and support the decarbonisation objectives of both Alpine and our stakeholders. Where appropriate, we will apply circular economy principles to extend asset value and reduce waste across our network and supply chain. We are committed to:

- Incorporate sustainability principles into infrastructure design to minimise construction waste and environmental impacts.
- Implement circular economy practices for materials, with a focus on reducing landfill waste through reuse and recycling.

- Apply sustainability criteria in procurement, including ethical sourcing and social responsibility throughout our supply chain.
- Consider indigenous biodiversity and protect significant natural areas (SNAs) where our network intersects with sensitive environments.
- Mitigate environmental and public risks associated with infrastructure, particularly in the use of Sulphur Hexafluoride ($SF_6$) and transformer oil.

## Information systems

Information systems are fundamental to effective asset management because they enable the integration, analysis, and accessibility of asset data across the entire lifecycle, from planning and design through to operation, maintenance, and renewal. Core platforms such as ERP, GIS, and SCADA provide the backbone for managing asset information, tracking performance, and supporting informed, risk-based decision-making. Chapter 8 of the AMP details our Digital Strategy, which is focused on modernising these core systems to deliver greater efficiency, resilience, and adaptability. Planned improvements include a new, consolidated ERP and EAM system, enhancing data integration, deploying advanced analytics, artificial intelligence capabilities and strengthening cybersecurity. These initiatives will enable better visibility of asset health, automate workflows, and support predictive maintenance, ultimately driving smarter investment, improved reliability, and a more responsive service for customers and stakeholders. By embedding digital transformation at the heart of asset management, we are aligning its capabilities with its strategic priorities and the external drivers shaping the sector, ensuring it can meet future challenges and deliver long-term value.

## Use of asset management data

We use asset management data to monitor, assess, and manage the lifecycle of assets across our network. This data supports every stage of the asset lifecycle, from procurement and commissioning through to maintenance, refurbishment, and eventual retirement. It provides us with a detailed understanding of each asset, including its age, manufacturer, model, location, condition, and performance.

This information enables us to identify risks, manage defects, and track the status of work orders and maintenance activities. By applying this data in a structured way, we can prioritise maintenance, plan replacements, and ensure that interventions are timely, effective, and aligned with network needs.

Asset management data also informs how we plan for growth and network development. It supports capacity assessments and investment decisions, ensuring that our network remains capable of serving both current and future customers. Our data-driven approach supports regulatory compliance, promotes transparency and accountability, and improves how we assess risk, manage our assets and meet our commitments.

## Informing asset health models

We apply structured condition assessment techniques to monitor asset performance and extend asset life. By identifying and addressing issues with key assets such as poles, distribution boxes, transformers, and ring main units before failure occurs, we reduce risk and maintain network reliability.

Asset management data is central to this process. In addition to asset condition, we assess risk factors such as location, age, environmental exposure, and weather history. This data informs our risk-based approach to maintenance planning and inspection scheduling.

We use a CBARM (Condition Based Asset Risk Management) approach to determine inspection timing, identify defects, and address condition-related issues. The outcomes of these inspections inform our asset health models, which in turn support maintenance planning, risk evaluation, and operational decisions. This proactive method helps maintain the safety, reliability, and efficiency of our network.

### Developing CAPEX projections

We develop our CAPEX projections by assessing asset needs, testing a range of investment options, and considering the wider strategic outcomes we must deliver. Condition based inspections and our CBARM models remain an important foundation, as they indicate where risk is emerging and where renewal or intervention may be required. However, these insights do not automatically lead to replacement. They trigger a broader assessment of the most appropriate response.

For each identified need we consider a full set of options, including refurbishment, targeted maintenance, alternative design approaches, innovative materials, and operational solutions that may defer or avoid capital expenditure. This includes the use of new monitoring technologies, such as fault passage indicators that communicate through cellular networks, which improve visibility and may reduce the need for physical upgrades. We also evaluate emerging technologies, including composite poles and composite crossarms, where they provide improved durability, safety, or environmental performance. Through this approach we balance cost, risk, sustainability, and regulatory compliance to ensure that our investments are justified, efficient, and aligned with our long-term strategy.

These insights also help us assess future asset needs, allocate resources, and ensure funding is available to maintain network performance while managing cost and risk exposure.

## 5.1. Asset management responsibilities

Clear governance and accountability are essential to delivering our asset management objectives. Responsibilities are distributed across the Board, Executive Leadership Team, and senior management to ensure decisions are strategic, informed, and aligned with our long-term goals.

### Board of Directors

The Board provides governance oversight of all asset management activities on behalf of shareholders and the broader community. Operating under the Board Charter, the Board reviews and approves our strategic direction, network performance standards, significant capital investments, and the overall budget envelope. Oversight is maintained through regular reporting, a structured delegated authority framework, and both internal and external assurance processes.

### Chief Executive Officer

The CEO is accountable for implementing the Board-approved strategic plan and ensuring that day-to-day operations, including asset management practices, align with our risk, performance, and investment expectations. The CEO oversees both strategic and operational risk management, service level outcomes, and the execution of the asset management strategy.

### Executive Leadership Team

The Executive Leadership Team (ELT) supports the CEO in delivering the asset management programme. Each ELT member operates within approved delegations and is responsible for ensuring delivery against budget and performance expectations. The ELT also provides regular updates to the Board on progress, challenges, and emerging risks related to the works programme and strategic initiatives.

# Management team

## Asset Management Steering Committee

The Asset Management Steering Committee ensures that our asset management activities align with our organisational strategy and support the delivery of the Asset Management Plan. It provides governance and oversight while guiding our strategic response to challenges such as decarbonisation, the rise of distributed energy resources, and the growing role of digital technology. Chaired by the Chief Assets Officer, the Committee meets quarterly or as required. Its membership brings together senior leaders, governance representatives, and subject matter experts, providing a range of insights and perspectives to inform key decisions.

The Committee sets priorities, monitors critical asset management initiatives, and supports communication between governance, leadership, and operational teams. It maintains oversight of compliance with ISO 55001 standards and leads efforts to strengthen asset management capability across the business. Through this role, the Committee promotes informed and transparent decision-making and supports the long-term stewardship of our network.

## Works Programme Committee

The Works Programme Committee (WPC) provides governance over the delivery of our works programme, ensuring alignment with strategic priorities, effective risk management, and efficient use of resources. The Committee supports the Executive Leadership Team by monitoring the delivery of the works programme, reviewing escalated project issues, and reinforcing investment decisions that reflect our strategy, budget settings, and risk appetite.

Meeting fortnightly, the WPC covers health and safety, performance delivery, project change requests (PCRs), resource planning, lessons learned, and project closeouts. Items requiring further escalation are raised to the ELT as appropriate. Membership includes senior leaders and technical specialists, responsible for reviewing risks, addressing resource gaps, supporting cross-functional coordination, and maintaining accountability for assigned actions. This governance structure ensures the works programme is delivered with transparency, consistency, and a clear line of sight to our long-term investment objectives.

## Assets and Operations

Our Assets and Operations business units are responsible for the end-to-end management of our electricity distribution network. These teams collectively oversee the direction and stewardship of network infrastructure, including the delivery of investment decisions that shape our future asset base. They manage the day-to-day operation of the network, deliver the AMP works programme, and provide essential engineering services to support planning and execution. Their role also includes enabling new customer connections, maintaining and replacing existing assets, and managing the integrity and accuracy of asset information across the business.

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

- Works Delivery oversees delivery of the works programme, maintenance schedules, vegetation management, and manages our procurement activities (see further detail below).
- Customer Commercial Services manages all new connection and alteration requests, including distributed generation (DG) applications.
- Asset Lifecycle manages assets throughout their life by developing maintenance schedules, analysing condition data, and overseeing the asset replacement programme.
- Future Network planning leads the strategic planning of the network to meet security of supply (SoS) requirements, future growth, and emerging demand.
- Engineering and Standards provides design and technical support to projects and leads the development and upkeep of our design standards.

- Network Intelligence maintains the accuracy and completeness of network connectivity data within our Geographic Information System (GIS) and provides spatial data insights and reporting.
- Operations manage the real-time operation of the network, including safe switching, fault response, and load management.
- Field Crews delivers construction, maintenance, fault response, and vegetation work to required safety and technical standards while working closely with the Works Delivery and Operations departments.

## Works Delivery

Our Works Delivery team oversees the execution of our work programme. They manage project delivery from procurement through to completion, ensuring risks are controlled and operational activities are coordinated effectively. Their key role is to ensure projects are delivered safely, on time, and within budget.

Works Delivery administers workflow between design, asset information, finance, and operations. This includes issuing job packs, obtaining quotes, raising purchase orders, and processing payments. They ensure that as-built information, inspection data, and field results are captured accurately and provided for asset information updates.

The team coordinates with field crews through regular operational meetings, reviewing upcoming workloads, resource availability, material needs, safety considerations, and operational risks. They manage contractor relationships, oversee contract performance, and facilitate forums such as the annual contractor safety refresher.

They are responsible for tendering projects, compiling contract documentation, and benchmarking supplier pricing against market rates. The team also manages critical spares, monitors vegetation risks through surveys and defect resolution, and issues customer notices where required.

Supporting the Works Programme and Delivery Committee, Works Delivery monitors programme performance, identifies risks and deviations, manages project prioritisation, and helps shape future work plans based on network risk, fleet strategies, and budget constraints. They also assist project managers with scheduling, cost tracking, and work programme delivery.

## Customer Commercial Services

Our Customer Commercial Services team manages customer connections and facilitates network alterations and associated projects when they are customer driven. They are involved across the asset lifecycle by identifying customer projects, highlighting them to the Works Programme and Delivery Committee, supporting design, and coordinating delivery and connection.

The team assesses network capacity for new connections, manages delivery in line with agreed terms, and ensures compliance with regulatory requirements, including the Electricity Participation Code. They maintain accurate customer connection records, oversee contract terms, and coordinate with councils on easements and development works.

Our Customer Commercial Services team also leads customer onboarding, facilitates distributed generation connections, resolves power quality issues, and supports revenue generation through both new and existing customer relationships. By applying structured processes and continuous review, our Customer Commercial Services team helps ensure reliable service outcomes and effective network risk management.

## Field Crew

Our Field Crew is responsible for the safe and efficient construction, maintenance, and repair of our electricity distribution network. Following the integration of our principal contractor into Alpine Energy Ltd., these teams operate under the direct governance of our asset management and operational frameworks.

The Field Crew delivers the physical works required to maintain network performance and support the delivery of our AMP objectives. Their responsibilities include constructing new network assets, upgrading existing infrastructure, undertaking planned and reactive maintenance, and responding to network faults and outages. They also carry out vegetation management, defect remediation, and asset inspections as part of our risk management and maintenance programmes.

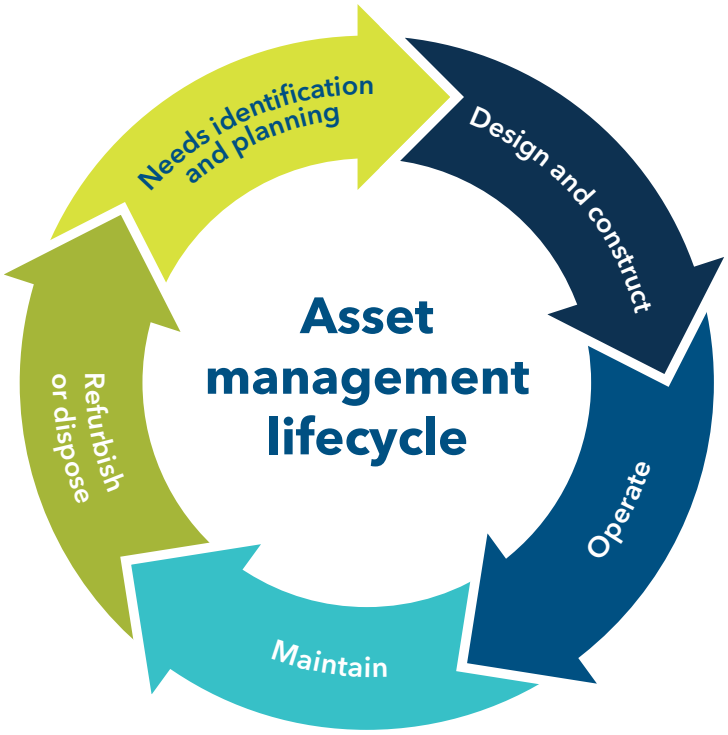
While the Field Crew does not hold direct Asset Management responsibilities, they are accountable for completing assigned work in accordance with safety standards, technical specifications, and approved work scopes. They work closely with the Works Delivery team and Operations to ensure alignment of field activities with planning, design, and network operations.

Our Field Crew operates under our governance, safety management, and quality assurance systems, ensuring that all work is performed to the standards expected of an electricity distribution business. This integrated delivery model allows us to maintain direct oversight of construction and maintenance activities, support workforce development, and enhance collaboration between planning, delivery, and operations.

## 5.2. Asset lifecycle management

We manage our assets across five lifecycle stages: planning, design and construction, operation, maintenance, and renewal or disposal (see Figure 13). This approach ensures our decisions are timely, risk-informed, and aligned with long-term network needs.

*Figure 13 | Asset management lifecycle*




Lifecycle management is embedded in our fleet strategies and supported by condition data, asset health models, and risk-based prioritisation. We use structured inspection and monitoring to assess asset condition and performance. These insights inform our maintenance schedules, renewal forecasts, and capital investment planning.

Our approach balances cost, safety, and service performance. We apply targeted interventions to high risk assets, and run-to-failure strategies to low risk assets, where life can be safely extended. We also consider non-network alternatives, such as demand-side management and distributed energy resources, where they offer cost-effective solutions.

Sustainability is integrated throughout the lifecycle. We apply circular economy principles, reduce waste, and manage environmental risks**.** Disposal decisions consider safety, cost, and site restoration, with reuse and recycling options assessed where feasible.

By applying lifecycle principles consistently, we maintain a safe, reliable, and efficient network while adapting to changing customer needs, climate risks, and regulatory expectations.

## Needs identification & planning

Central to the needs identification & planning stage is planning our network. We use the term 'network planning' to describe how we identify, assess, consider options and respond to future electricity demand across South Canterbury. This includes capital investment to expand network capacity, improve reliability, and enable customer connections. It also covers upgrades to support electrification, distributed generation, and climate resilience.

Our detailed network planning approach is covered in Chapter 6.

Our planning process is scenario-based and data-driven. We use bottom-up demand forecasting, customer engagement, and modelling tools to assess future needs. Our Energy Roadmap sets out long-term infrastructure requirements through to 2040, informed by regional development, industrial decarbonisation, and climate risk.

We evaluate investment options using structured criteria and develop Network Development Plans for each GXP region. These plans guide our delivery of new assets and ensure we maintain service levels while adapting to changing customer and environmental conditions.

## Design and construct

We apply consistent design and construction standards to ensure new assets are safe, reliable, and fit for purpose. These standards are aligned with AS/NZ requirements and supported by detailed technical specifications that guide materials, workmanship, and performance expectations.

Our detailed approach to design and construction is covered in Chapter 6.

Design governance is embedded across our delivery processes. Our engineering team leads the development and maintenance of design standards, while our drawing management system ensures version control and traceability. Field crews and contractors follow approved designs and specifications, with oversight from our Works Delivery team to ensure projects are delivered safely, on time, and within budget.

Sustainability is integrated into design and construction. We apply circular economy principles to reduce waste, reuse materials, and minimise environmental impact. Our Asset Management policy guides environmentally sustainable procurement decisions, promotes ethical sourcing, and ensures biodiversity protection where our network intersects with sensitive environments. We also manage environmental risks associated with infrastructure.

## Operations

We operate our network to deliver safe, reliable electricity across South Canterbury. Our Control Centre provides 24/7 monitoring, managing real-time network status, switching, and fault response. Controllers use SCADA to monitor asset performance, coordinate field crews, and manage controllable load to maintain supply security.

SCADA provides live data on voltages, current flows, and equipment status. It enables remote switching, alarm-based fault detection, and automated restoration. We are expanding SCADA functionality to support mobile access, electronic switching preparation, and integration with outage management systems.

Operational resilience is a key focus. We are increasing remote control capability for field devices, including reclosers and voltage regulators. We are also integrating SCADA with GIS, ERP, and CRM platforms to improve situational awareness and asset data management.

Field automation, mobile access to asset data, and drone-assisted inspections are being rolled out to improve safety, responsiveness, and efficiency. These upgrades support faster fault isolation, reduce outage durations, and enable more informed decision-making.

Our operations strategy ensures the network remains responsive, resilient, and ready to meet evolving customer and environmental demands.

### Maintenance

We maintain our assets to ensure safety, reliability, and performance throughout their lifecycle. Our maintenance strategy includes four work types:

- Preventive: Scheduled inspections and servicing to prevent failure and assess condition.
- Corrective: Responsive repairs following faults or defects.
- Predictive: Condition-based monitoring to anticipate issues before failure.
- Proactive: Reliability-driven improvements to reduce risk and enhance performance.

These activities follow a continuous improvement cycle: assess asset condition, specify tasks, deliver work, and review outcomes. We plan and deliver maintenance through structured programmes, supported by asset condition data, reliability analysis, and operational insights.

We also manage vegetation to maintain line clearance and reduce outage risk. Our approach combines cyclical scheduling with risk-based targeting, informed by terrain, growth rates, and outage history. We work closely with contractors and landowners to ensure safe, efficient delivery and community engagement.

To improve effectiveness, we are investing in drone-assisted inspections, mobile data collection, and upgraded geospatial tools. These technologies enhance safety, accuracy, and responsiveness, while supporting better planning and coordination.

### Renewal or disposal

We renew or dispose of assets based on condition, risk, and cost. End-of-life decisions are guided by structured assessments that consider asset health, performance history, safety risks, and regulatory changes. We prioritise renewal where failure risk is high or where assets no longer meet service or compliance requirements.

Our approach balances age-based expectations with condition data. Assets that remain reliable beyond their nominal life may be refurbished, while those with systemic faults or elevated risks are replaced early. We apply CBARM models to forecast renewal needs and inform capital planning.

Renewal is used to extend asset life where condition supports it. Mid-life interventions include component upgrades, insulation testing, and arc flash safety enhancements. These practices reduce risk and defer replacement, improving lifecycle value.

Disposal is carried out safely and in line with environmental regulations. We recover and recycle materials such as $SF_6$ gas, transformer oil, and metals. We assess reuse opportunities for decommissioned assets and apply circular economy principles where feasible.

This approach ensures our network remains safe, resilient, and cost-effective, while supporting our sustainability goals and regulatory obligations.

## 5.3. Maturing our asset management

Improving our asset management maturity is a key focus for Alpine and central to our commitment to continuous improvement. We assess our maturity using the Commerce Commission's Asset Management Maturity Assessment Tool, which measures capability across strategy, governance, risk management, systems, and information.

Our Powering Up Our AMMAT Score Programme focuses our improvement efforts on strengthening alignment with ISO 55000 principles, enhancing internal collaboration, improving decision-making, managing risk, and ensuring regulatory compliance. The programme provides a structured and systematic approach to asset management, helping us optimise performance, cost, and risk across our asset base.

The CutlerMerz review provided additional insight into our maturity uplift needs. It found that our current practices are generally appropriate for a network of our scale, while also identifying opportunities to improve the consistency of supporting documentation, clarify the reasoning behind project timing and sequencing, and apply more structured, data driven methods across asset classes.

An internal assessment will be completed in FY26, which we expect will provide us with the opportunity to validate progress we have made in areas such as governance and fleet strategies, whereas improvement opportunities that remain in integration, communication, and training. Our current average maturity score stands at 1.97.

The Board and leadership team are committed to achieving a score of three in each AMMAT category by FY28. This will be supported through a structured programme of documentation, training, and ongoing engagement across the business. Through this work, we aim to strengthen regulatory confidence, align internal practices, and build lasting asset management capability. Details of our latest assessment and improvement initiatives are provided in Appendix D (Schedule 13).

# 6. Developing our future network

This section outlines Alpine Energy's strategic investment theme of growth and enablement. These investments are critical to delivering on the strategic objectives set out in the strategic AMP, particularly those related to supporting electrification, improving resilience, and empowering customers to actively participate in the energy system. The theme responds to evolving demand patterns, regional growth, and the increasing need for a flexible, future-ready network.

## 6.1. Investment summary

The table 11 below provides an overview of the material projects proposed under the growth and enablement of investment theme. Each project is directly aligned with Alpine Energy's Asset Management Plan (AMP) priorities, detailing their timing, budget, and expected outcome to support the strategic objectives outlines in the section.

*Table 11 | Summary of material growth and enablement projects*

| Project | Description | Cost ($'000) | Timing |
|---|---|---|---|
| **Zone substation in Washdyke** | New zone substation that strengthens sub-transmission capacity and enables connection of future industrial and commercial growth in the Washdyke area. | 15,000 | FY34 |
| **Pleasant Point zone substation upgrades** | Upgrades to existing zone substation assets to relieve transformer constraints and provide the additional capacity required to support local demand growth. | 1,500 | FY32 |
| **Pleasant Point sub-transmission upgrade** | Strengthens the sub-transmission supply to Pleasant Point, alleviating constraints and improving security of supply for existing and future customers. | 7,000 | FY32 |

## 6.2. Network planning approach

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.

### Security of supply standard (SoSS)

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.

*Table 12 | Security levels*

| 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.<br>Meaning the lost load will be restored in the time it takes to repair the fault.<br>Restoration of 50% of the lost load in switching time has also been considered as sub-criteria under N. |
| N-1 | N-1 is the security level that ensures supply after a single contingency event.<br>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.<br>Meaning no load will be lost due to consecutive failures on two separate circuits. |

Quality of electricity supply provided to the customers in another important aspect of business. There are multiple factors that affect the quality of supply to our customers. These include but are not limited to:

- Customer installations, non-linear devices like variable speed drives (VSDs), DG inverters and uninterrupted power supplies 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 10% of the nominal voltage (230V for single phase). This 10% 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 Code. However, changes have also been proposed to Part 6 of the Code on DG which are expected to take effect from 2026.

## 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 Figure 14 below:

*Figure 14 | Our network 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 considers 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.

## 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.

Forecasting demand on electricity distribution networks is becoming more complex as new factors emerge. Public EV charging, sudden large customer connections, growth in distributed generation, rising EV uptake, and broader decarbonisation trends are all changing how and when electricity is used. These shifts mean forecasting now needs to account for more uncertainty and evolving patterns in demand. We use a Customer Relationship Management System (CRM) to record new customer step loads, enquires, and opportunities.

We also use CRM System 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 two potential future scenarios:

*Table 13 | Scenario options overview*

| Scenario options | Description |
|---|---|
| **Accelerated growth** | High economic development trends, high population growth, aggressive EV uptake trajectories and expansion of public EV charging infrastructure. New customer loads with Probability of Exceedance of 10% considered. Base line growth is based on the historic organic growth of peak electricity demand. |
| **Balanced growth** | Slow and steady economic development trends, moderate uptake of EVs, steady expansion of public EV infrastructure. New connection step loads with Probability of Exceedance 50% considered. Base line growth is based on historic organic growth in peak electricity demand.<br><br>Note: Our AMP expenditure forecasts have been based on this expected scenario. |

Our step load changes or request for large capacity increases are categorised by their likelihood as follows:

*Table 14 | Likelihood categories overview*

| General time-based guide | Description | Likelihood Percentage | Likelihood category |
|---|---|---|---|
| **Within 0-1 years** | A customer already applied to increase their allocated network capacity and committed for projects | >=90 | **Confirmed** |
| **Within 1-3 years** | A customer already applied for a capacity increase, some aspects of the work such as consents and financing have been completed. But, some are not. | 75 =< & < 90 | **Very Likely** |
| **Within 3-5 years** | Customer projects for demand increase likely to happen, but aspects of the work yet to be finalised | 50 =< & < 60 | **Likely** |
| **Within 5-10 years** | Customer load increases that are possible to materialise, but still uncertain. | 25 =< & < 50 | **Possible** |
| **After 5 years** | Speculative and highly uncertain customer projects that require capacity increases | <25 | **Speculative** |

## Forecasting and modelling

Our peak network demand forecast consists of several components: organic demand growth, residential EV uptake, public EV charging infrastructure development and step load additions (new customer connections) or changes. We use a bottom-up approach to aggregate the demand upstream. The two forecasting scenarios: Balanced Growth and Accelerated Growth are then developed capturing these demand growth components.

Alpine Energy uses ETAP software to model its electricity network, including all assets up to the low-voltage bus of distribution transformers. We create multiple modelling scenarios based on customer feedback, SCADA data, and smart meter verification. This approach helps us develop realistic plans and avoid unnecessary investment in the network. All proposed new loads and DGs are added to our master network model to ensure accurate and efficient future planning. Load flow analysis is used to assess the network's performance under worst-case scenarios. It ensures the network complies with voltage regulation limits during both low and high load conditions.

## Network Development Plans

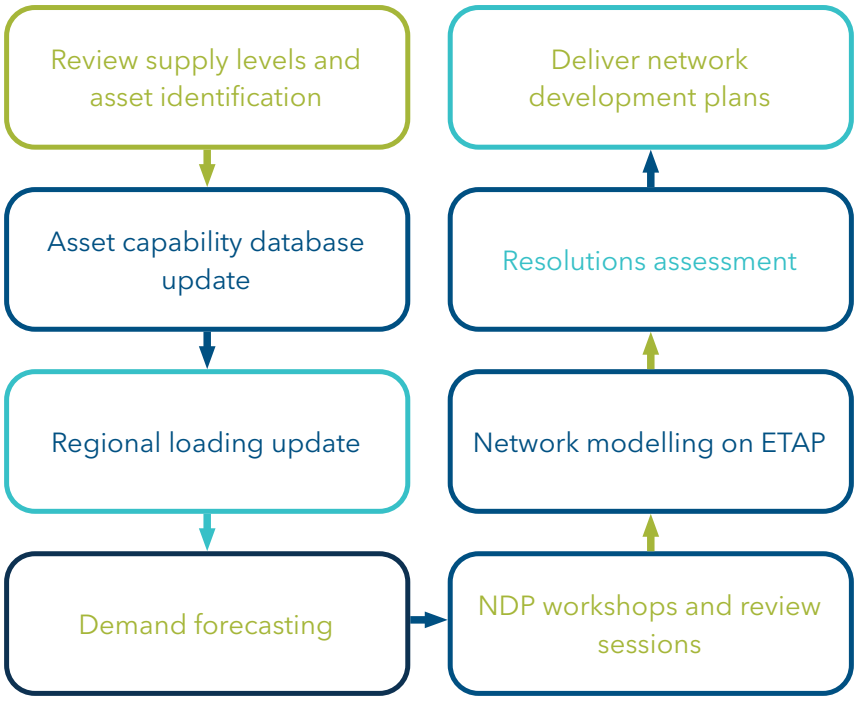
Using our asset management demand forecasting, modelling, and options analysis, we then prepare Network Development Plans (NDP). NDPs are prepared for each of the seven GXP regions.

- Albury
- Bells Pond
- Studholme
- Tekapo
- Temuka
- Timaru
- Twizel

We ensure that our network capacity and voltage levels at every point of supply are sufficient to meet both current and forecasted future customer demands. This process applies the methodologies described above within a structured framework to develop the annual Regional Network Development Plans (NDPs) for the entire network.

The process follows the key steps outlined earlier, implemented at a regional level. A summary is provided below (Figure 15):

*Figure 15 | Network development planning process*




## Expenditure categories

All network investments are divided into the following expenditure categories (in line with ID requirements), which are mapped to our investment themes:

*Table 15 | Mapping of expenditure categories to investment themes*

| Expenditure Category | Investment Theme |
|---|---|
| Customer connection (CC) | Growth and enablement |
| System growth (SG) | Growth and enablement |
| Asset replacement and renewal (ARR) | Renewal and resilience |
| Asset relocations (AS) | Renewal and resilience |
| Reliability, safety and environment (RSE) | Renewal and resilience |
| Other reliability, safety, and environment | Renewal and resilience |
| Quality of supply | Support and transformation |
| Legislative and regulatory | Support and transformation |

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

### 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 the latter sections.

### 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.

## 6.3. Network development plans

### Our energy roadmaps

Adopting a dynamic and responsive approach to network planning demonstrates our dedication to meeting the evolving needs of our customers and communities, considering our long-term investment drivers.

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 states by 2036 and beyond 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 cover the key inputs into South Canterbury's energy requirements. This includes 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:

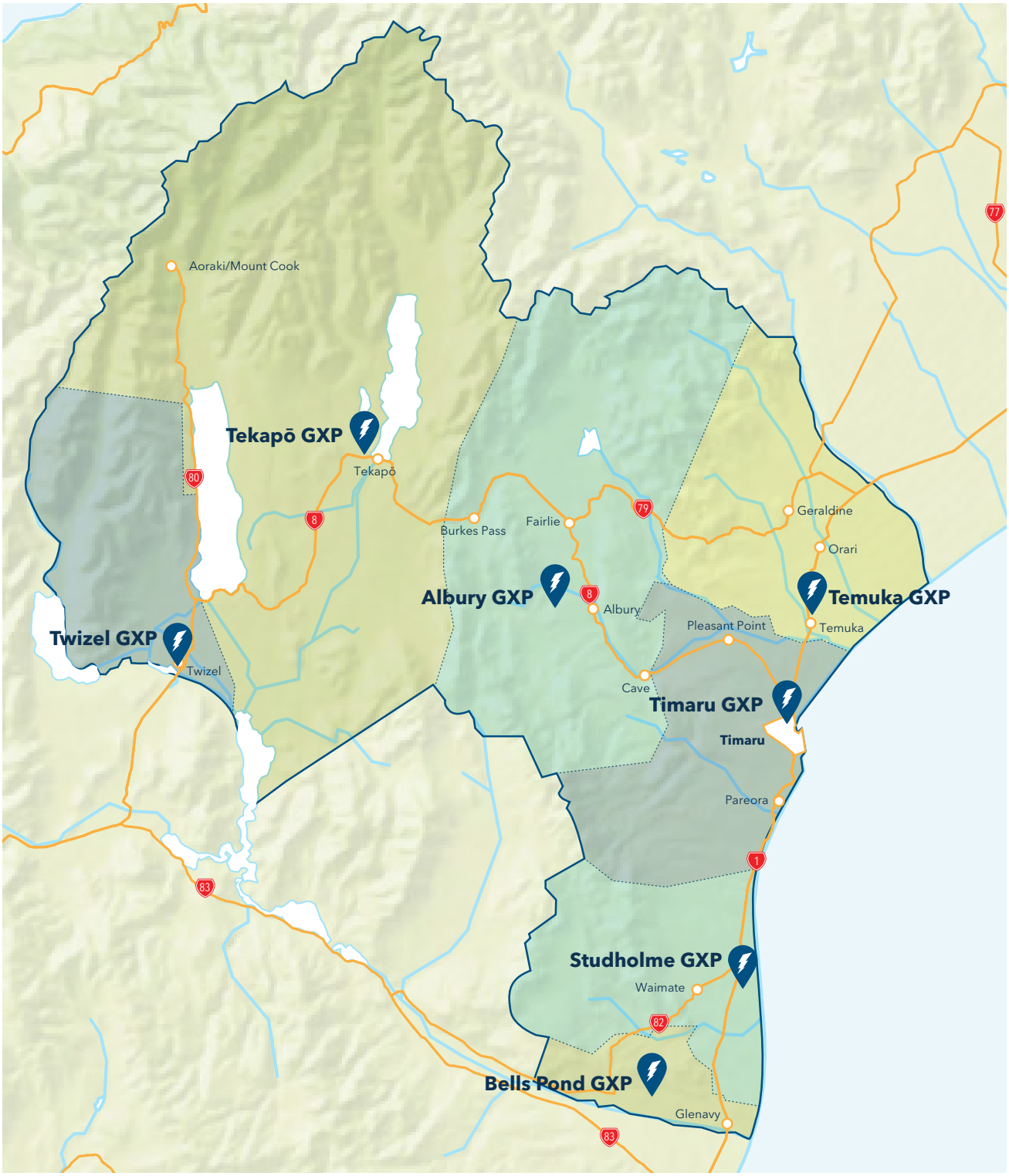
- Estimated energy requirements by sector
- Peak load
- Estimated energy requirements by region / existing / future substation requirements
- Details of assumptions for each sector / region and rationale behind these assumptions
- Future SoS considerations while considering possible load shed alternatives, 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.

## Overall network demand forecast

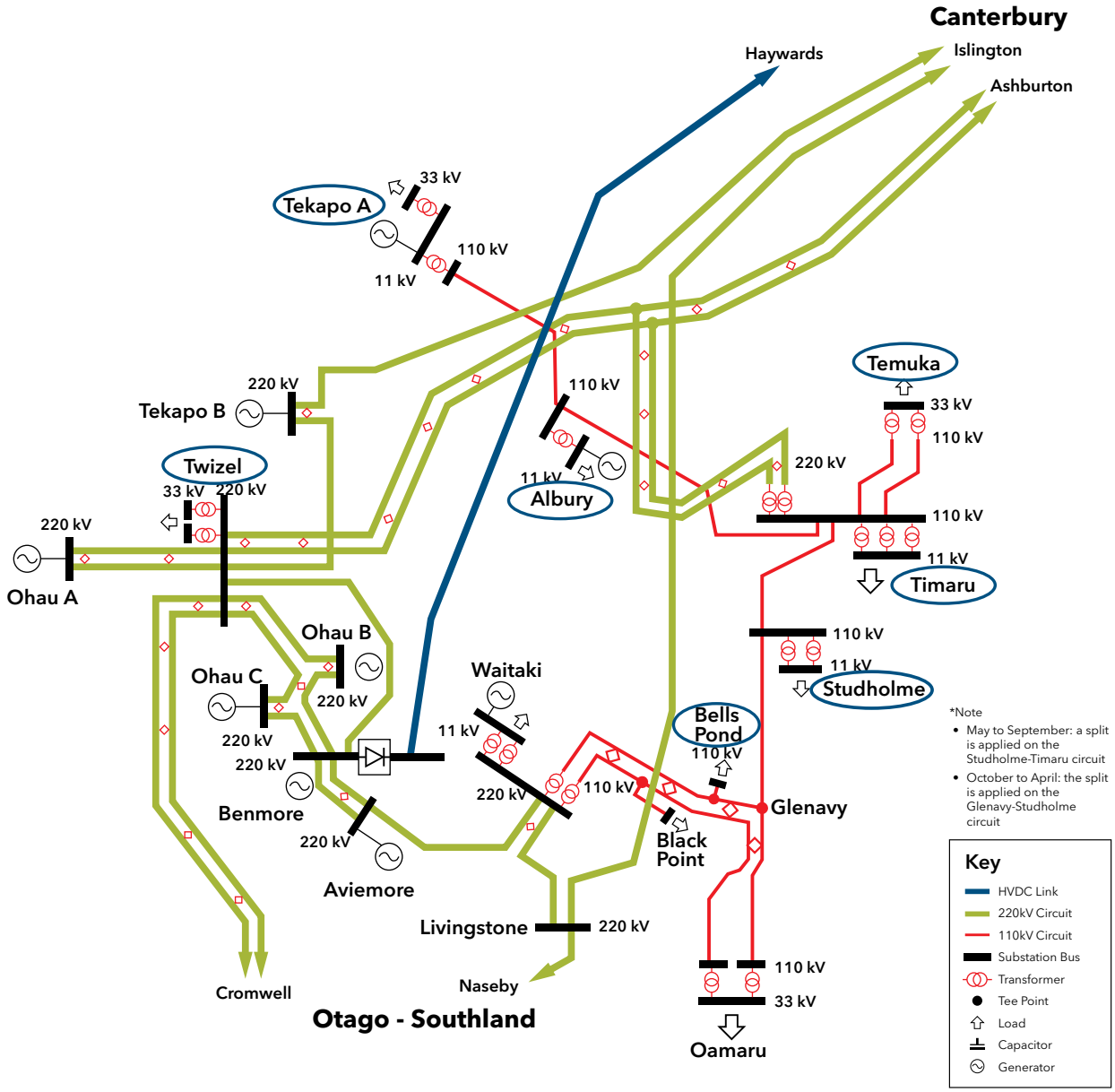
This section outlines our network growth for the next 10 years. Figure 16 below shows a geographical map of how our electricity distribution network is spread across South Canterbury.

*Figure 16 | Alpine Energy's seven GXP regions in South Canterbury*



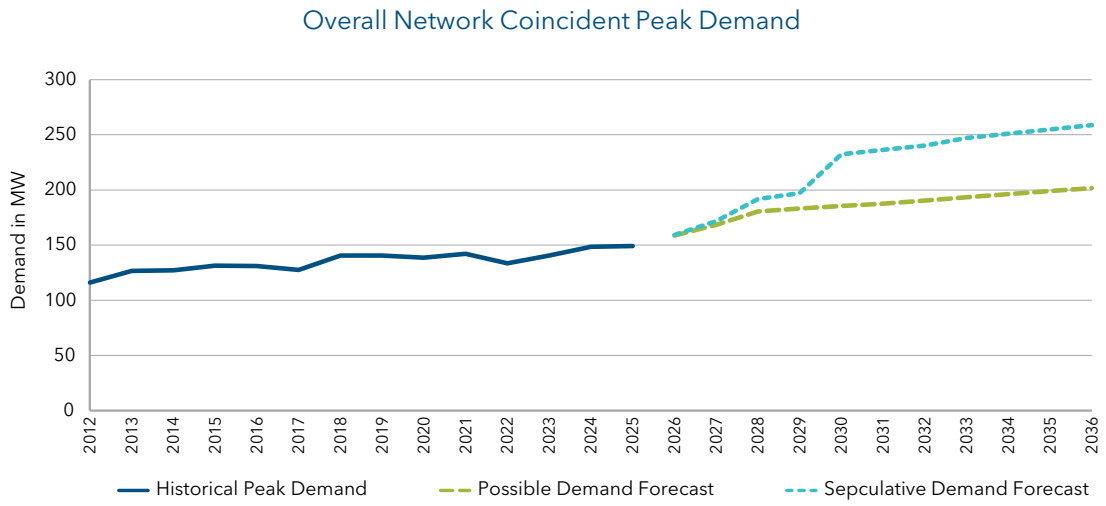
Our 7 grid exit points off Transpower's transmission network are shown below.

*Figure 17 | Grid exit points to Alpine off Transpower's network*




The growth expected on our network over this next AMP period is significant. The graph below shows the potential expected uplift from a base of 150 MW to around 200 MW under the "possible demand forecast scenario" 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 energy customers to balance our load at peak times.

*Figure 18 | Overall network peak demand forecasts*




# Regional network forecasts

## Timaru GXP region

### 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:

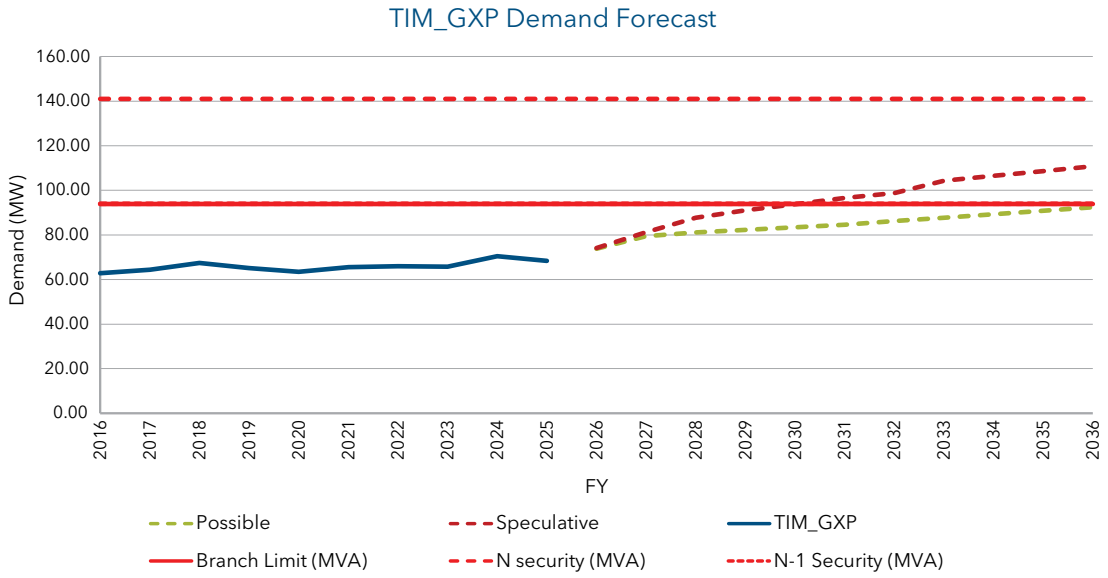
- Timaru Zone Substation
- Pareora Zone Substation
- Pleasant Point Zone Substation
- Washdyke Switching Station
- Grasmere Switching Station
- North Street Switching Station
- Hunt Street Switching Station.

| 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-1 | N – 1 | 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 | *Timaru – Grasmere & Grasmere – Hunt St. sub-transmission at N. Others at N-1 security. Overall N-1 switched.<br>There is inter-connectivity on the 11kV feeders and 400V reticulation. |
| **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 step change in growth expected.

*Figure 19 | Timaru GXP demand forecast.*




## Existing constraints and key projects

Forecast growth within the Timaru GXP has decreased compared to precious forecast which can be attributed to economic strains and uncertainty. Anticipated load growth has been shifted further out beyond 2030.

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 has been a key project in previous AMPs. 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.

However, with a decrease in the expected step load growth in Timaru and Washdyke industrial area we have reassessed the timing and capacity the requirements of the new 33kV. Continuous monitoring and close collaborations with relevant industry partners are taking place. According to the current forecast (Possible scenario), GXP transformer capacity-based N-1 security limit is expected breach in 2034/2035.

However, our speculative forecast shows that Timaru peak demand could reach GXP N-1 capacity limits as early as FY 2030. We will closely monitor the situation, engaging with customers, industries, and Timaru District Council to understand economic trends that impact our demand forecasts.

## Timaru Zone Substation

Timaru Zone Substation currently supplies to Pareora and Pleasant Point by two step-up transformers 19/25 MVA 11/33kV located in Timaru GXP site. The 33kV bus is split, and feeds Pareora Zone Substation transformer 1 and the other feeds Pareora Zone substation 2 and Pleasant Point Zone Substation. The demand forecasts for the next 10 years for each of Timaru Zone Substation transformers are as follows.

*Figure 20 | Timaru Zone Substation 1 Demand Forecast.*

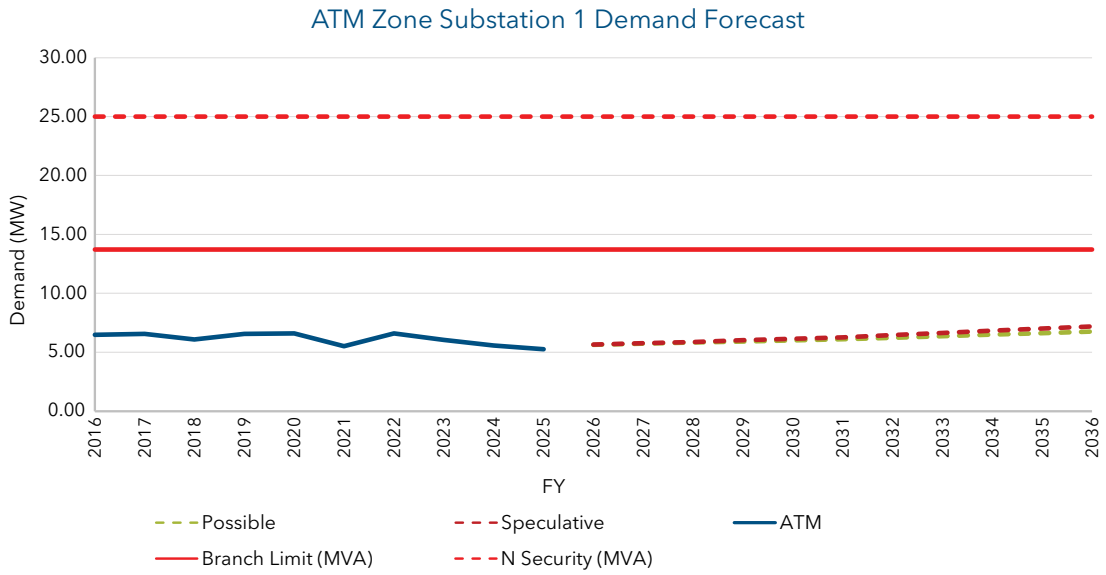
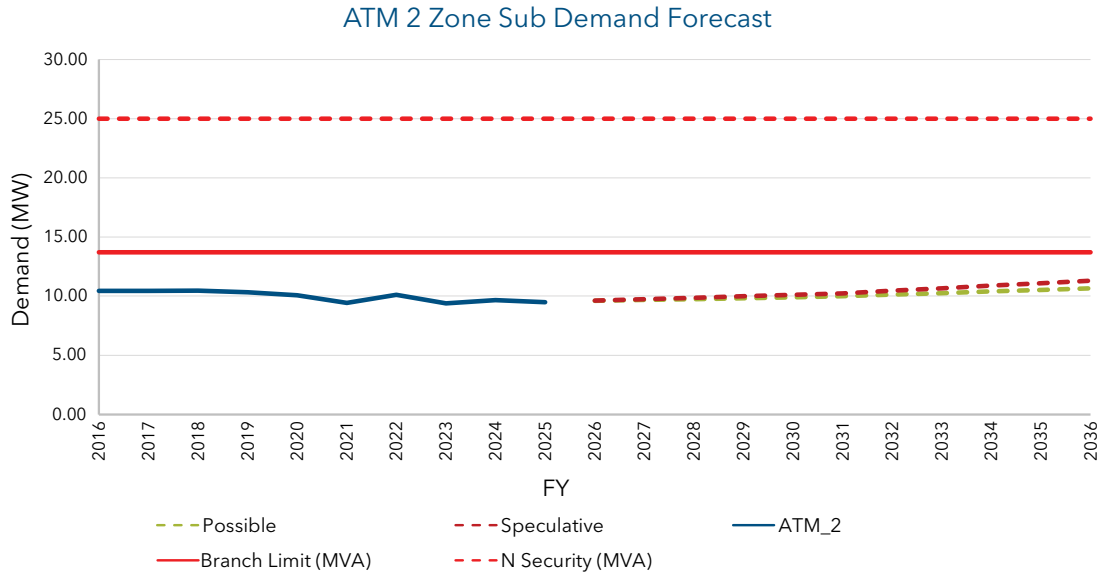


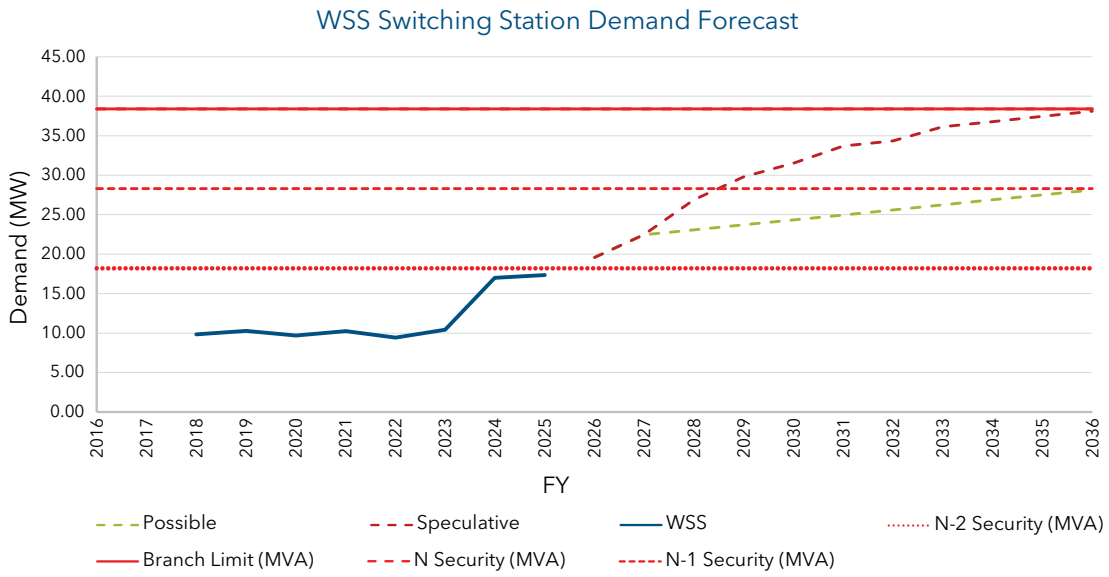

*Figure 21 | Timaru Zone Substation 2 Demand Forecast.*




## Washdyke Zone Substation

The new Washdyke swiching station was completed in FY26. However, the project to build a zone substation in Washdyke, aligning with the construction of a new 220/33kV GXP in Timaru, has been deferred due to the reduction and shift in timing of the expected new loads in Washdyke. Based on the current forecast (Possible scenario), N-1 capacity limit on the incoming circuits to Wasdyke switching station will not be breached during the current planning horizon. We will closely monitor developments and engage with customers to understand the capacity requirements to re-assess upgrade options.

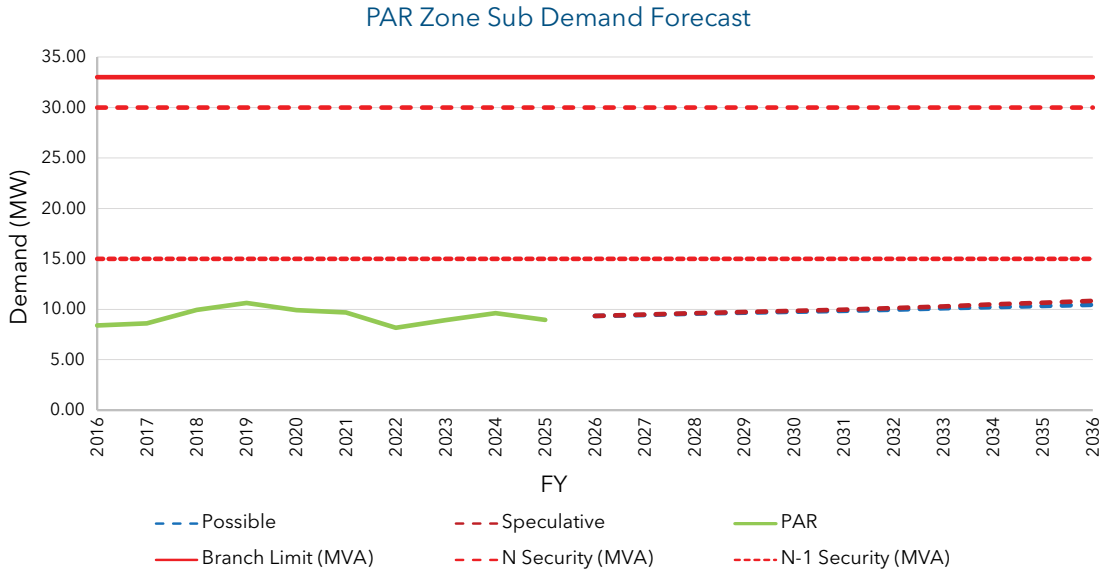
*Figure 22 | Washdyke Switching Station Demand Forecast.*




## Pareora feeder

Our Pareora Zone Substation demand is running close to our N-1 security limit due to a constraint on the incoming 33kV overhead sub-transmission circuit connecting Timaru GXP to Pareora. However, a major part of load in Pareora is driven by a single large customer, so future upgrades will be tied with the level of security of supply this customer is prepared to accept.

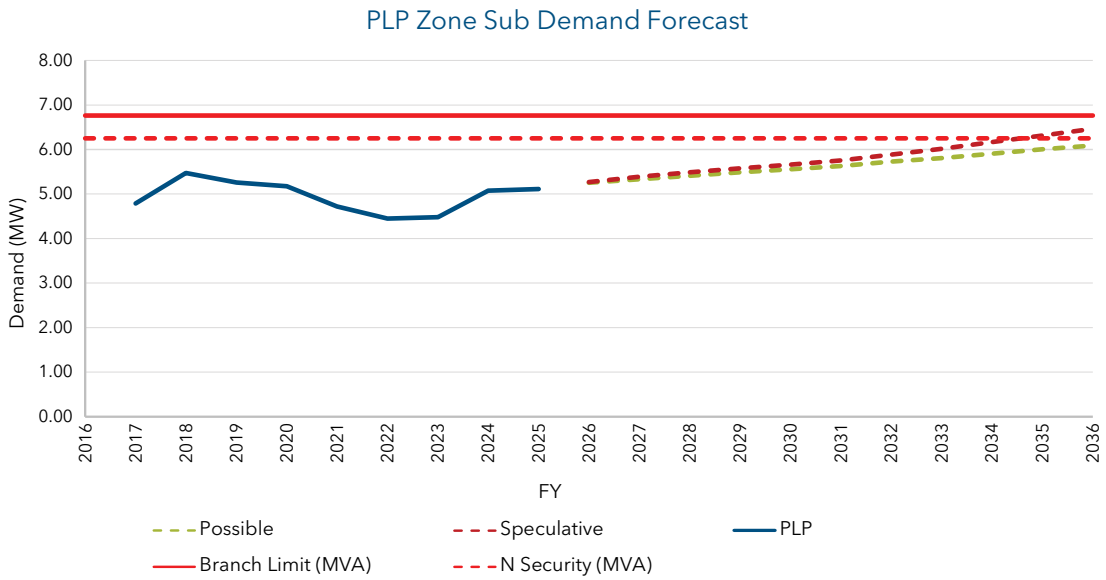
*Figure 23 | Pareora Zone Substation Demand Forecast.*




## 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 build a new substation, replace the circuit breakers (CBs) and install a second transformer.

*Figure 24 | Pleasant Point Zone Substation Demand Forecast.*




## Timaru urban growth response plan

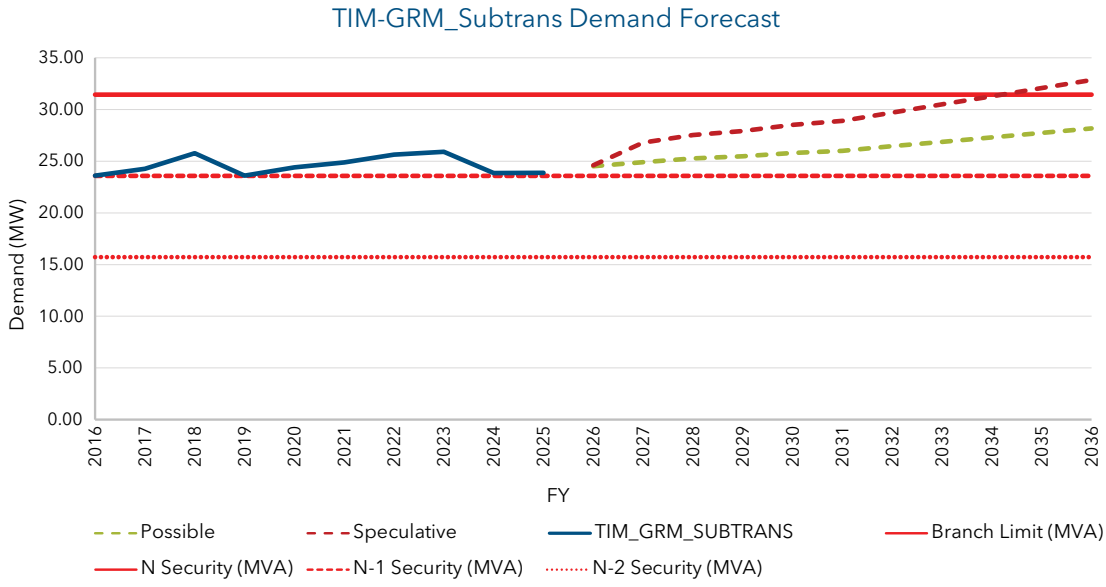
In Timaru city there are various other areas of expected growth, outside of the Washdyke area. These are: Timaru Port and the CBD, continued residential growth through housing provision, and the transport electrification.

Timaru CBD and Port are fed from a network of three switching stations with dedicated interconnections and incoming circuits (Sub-transmission circuits) from Timaru GXP 11kV bus. We are experiencing security of supply issues in sub-transmission circuits from Timaru GXP to Grasmere switching station, and on ties between Grasmere and Hunt Street switching stations.

## Timaru – Grasmere St. sub-transmission network

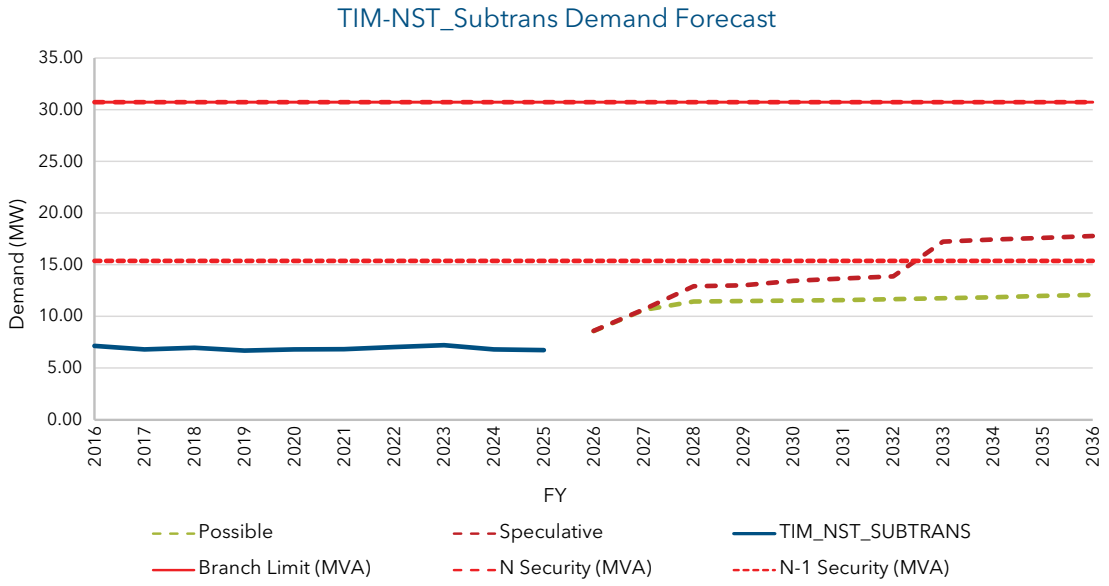
The Timaru – Grasmere St. sub-transmission network peak loading has exceeded our N-1 security of supply criteria for certain periods of time in winter when the network demand in Timaru is at its peak. There are four underground circuits feeding Grasmere St. from Timaru. These cables also have ageing and resilience concerns, and we have identified short term, medium term, and long-term measures to alleviate the issues.

*Figure 25 | Timaru – Grasmere sub-transmission Demand Forecast.*



## Timaru – North St. sub-transmission network

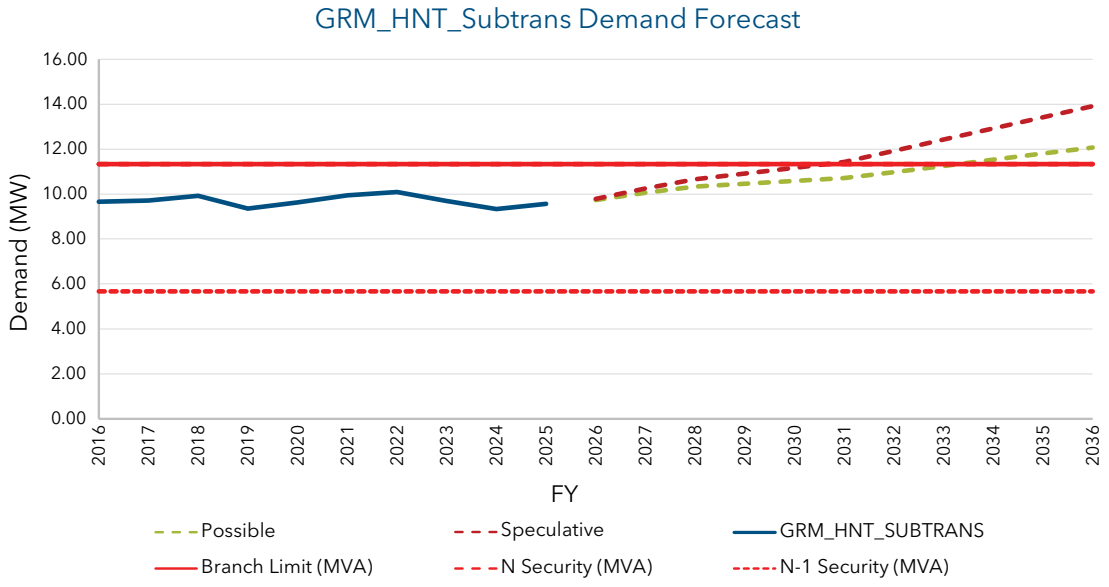
*Figure 26 | Timaru – North St. sub-transmission Demand Forecast.*




## Grasmere St. – Hunt St interconnection

There are two 11 kV ties between Grasmere St. and Hunt St. switching stations. These two circuits breach N-1 security limits and during peak time loading in winter and have resilience and ageing issues too. Peak demand forecast is expected to reach N capacity limit in by 2028-2029. A network project is underway to alleviate the issue by building two more interconnection ties between the two switching stations.

*Figure 27 | Grasmere St. – Hunt St interconnection Demand Forecast.*




## HV feeder level upgrades

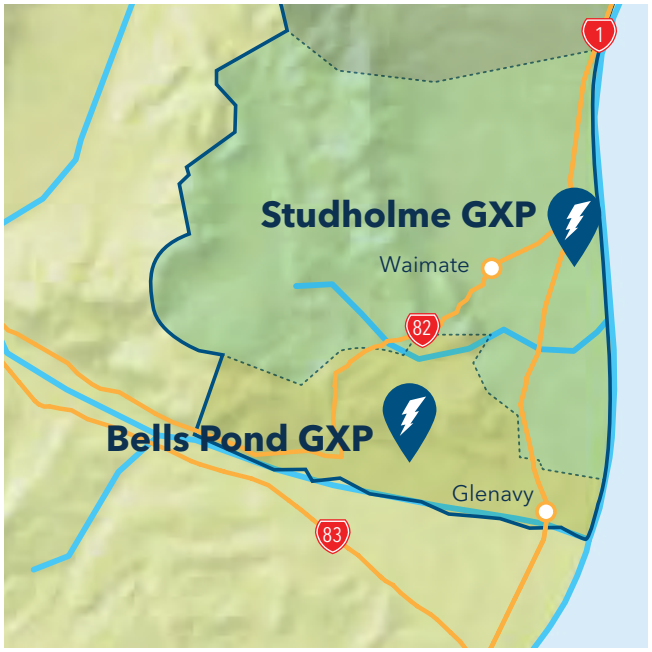
Based on our demand forecasts, we have also identified constraints at 11kV feeder level within Timaru, and projects are being formulated to alleviate the issues.

# Bells Pond GXP region

## 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 Glenav and is supplied from Bells Pond GXP. The largest irrigation scheme within the Bells Pond Region is presently the Waihao Downs irrigation scheme.

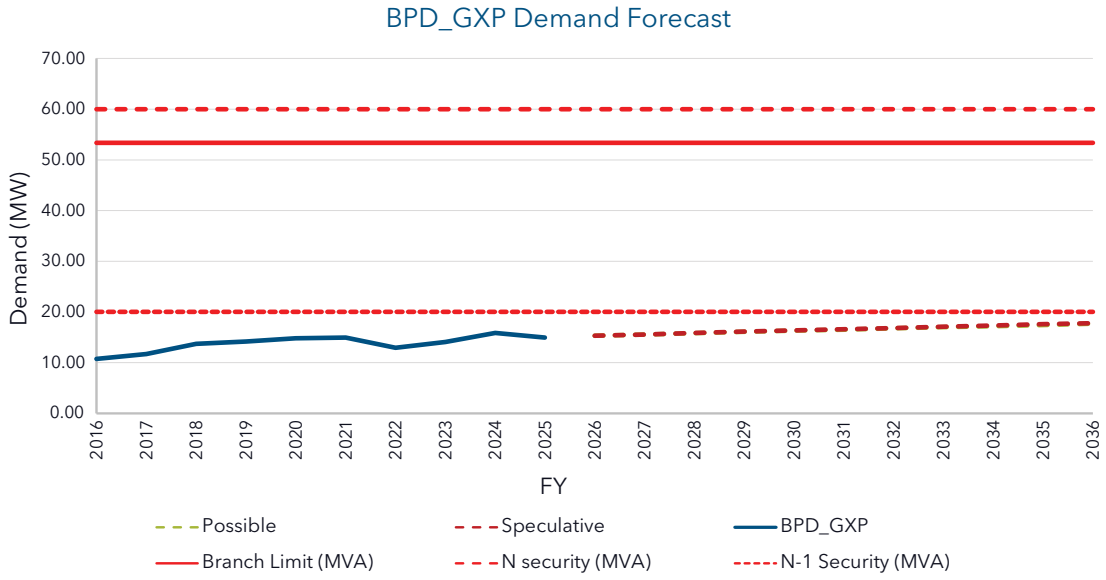
*Figure 28 | Bells Pond GXP region*




## Bells Pond demand forecast

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

*Figure 29 | Bells Pond GXP Demand Forecast.*



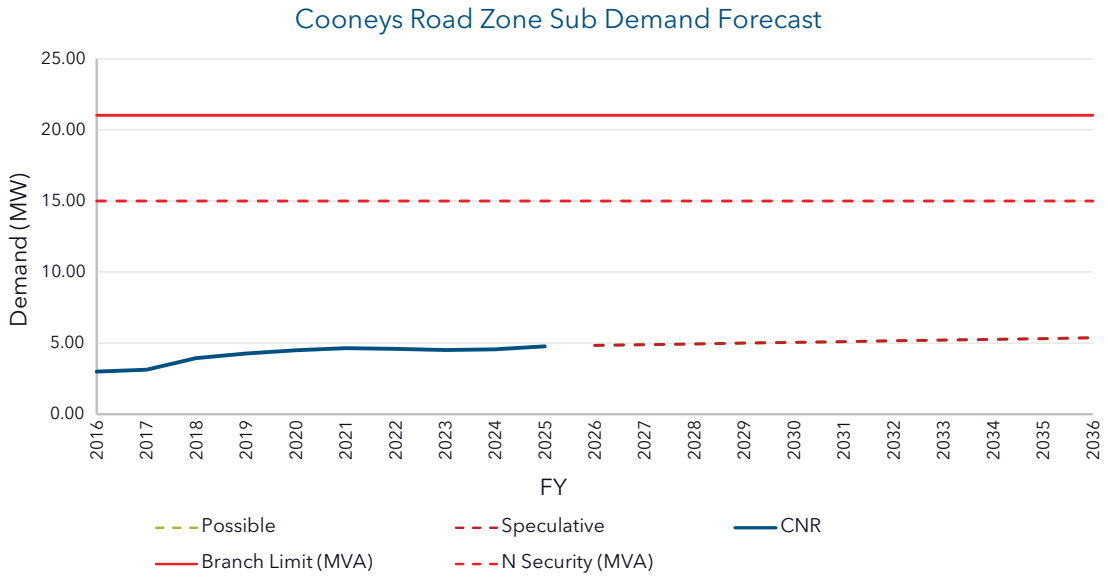

Bells Pond GXP consists of 110/33/11kV GXP with two transformers which owned by us including all the downstream assets. Therefore, it is considered as a zone substation in Alpine Network.

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 and no major capacity increases are not expected at ODL over the current planning horizon.

## Cooneys Road substation upgrade

One large customer is supplied from Cooneys Road Zone Substation 33/11kV, 15 MVA at N security. 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 30 | Cooneys Road Zone Substation Demand Forecast.*




## Security of supply

Table 16 below outlines the SoS for the zone substations and on the sub-transmission network in the region.

*Table 16 | Bells Pond SoS*

| GXP/Sub-transmission/ Zone Substation | Actual | Target | Comment |
|---|---|---|---|
| **Bells Pond GXP** | N-1 | N-1 | Security target is met for this planning period in accordance with our SoSS.<br>Transpower has transmission configuration changes that would allow some or all supply to be restored. Transpower has evaluated as 'Low Economic Consequence'1 |
| **Bells Pond Zone Substation**<br>**11kV**<br>**33kV** | <br>N-1<br>N-1 | <br>N-1<br>N-1 | Security target is met for this planning period in accordance with our SoSS. |
| **Cooneys Road** | N | N | Restoration of 50% of the lost load in switching time. Security target is met for this planning period in accordance with our SoSS. |
| **Bells Pond – Cooneys Rd. sub-transmission 33kV** | N-1 Switched | N-1 Switched | Security target is met for this planning period in accordance with our SoSS |

## Existing and forecast constraints

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.

## Large scale DGs

We have received a number enquires and applications for large scale solar farms in Bell Pond GXP region. We are currently evaluating the feasibility of one large scale DG while the others are at early enquiry stages.

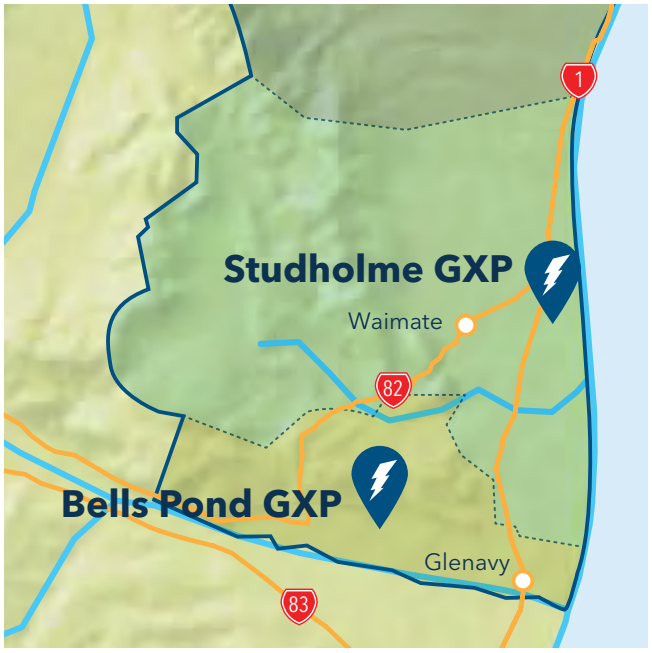
# Studholme GXP region

## 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.

*Figure 31 | Studholme GXP region*




## Security of supply

Table 17 below outlines the Studholme GXP SoS:

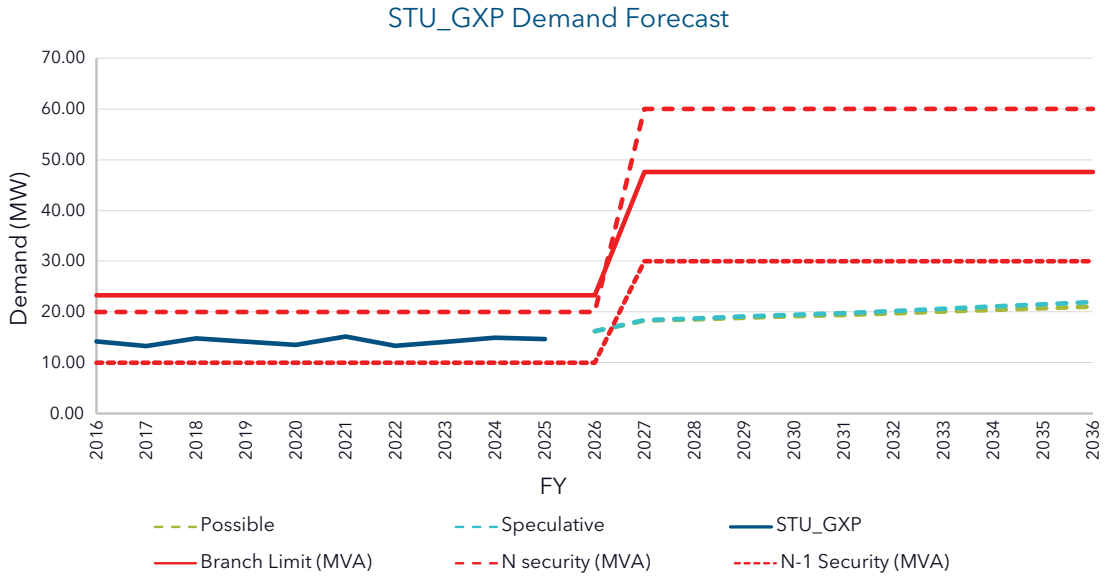
*Table 17 | Studholme GXP SoS*

| 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.<br>Transpower has evaluated this GXP as 'Material Economic Consequence' and Transpower plans to upgrade the transformers to 2x30 MVA for the exiting 2x10 MVA between 2025 and 2027. |

## Studholme demand forecast

The demand forecasts for the Studholme GXP are shown below.

*Figure 32 | 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 in 2027. Until then, we do not anticipate any capacity constraints in the region. These new transformers will have a capacity of 2x30MVA, which will help to restore the N-1 supply security.

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. We have not identified any major load increases in the area; however, we are engaging with customers to proactively identify such opportunities.

During the outages of Bells Pond GXP, Oceania Dairy Factory is supplied from Studholme GXP, which causes CB9 Morwan feeder to be strained. Additionally, a few feeder level constraints are expected to emerge in the second half of the forecasting period.

# Temuka GXP region

## 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 (34 MW of peak 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 around 3,100. Geraldine benefits from the passing of tourists through the inland scenic route.

*Figure 33 | Temuka GXP region*


## Security of supply

The SoS of Temuka GXP and its associated regional zone substations are outlined in Table 18 below.

*Table 18 | Temuka GXP SoS*

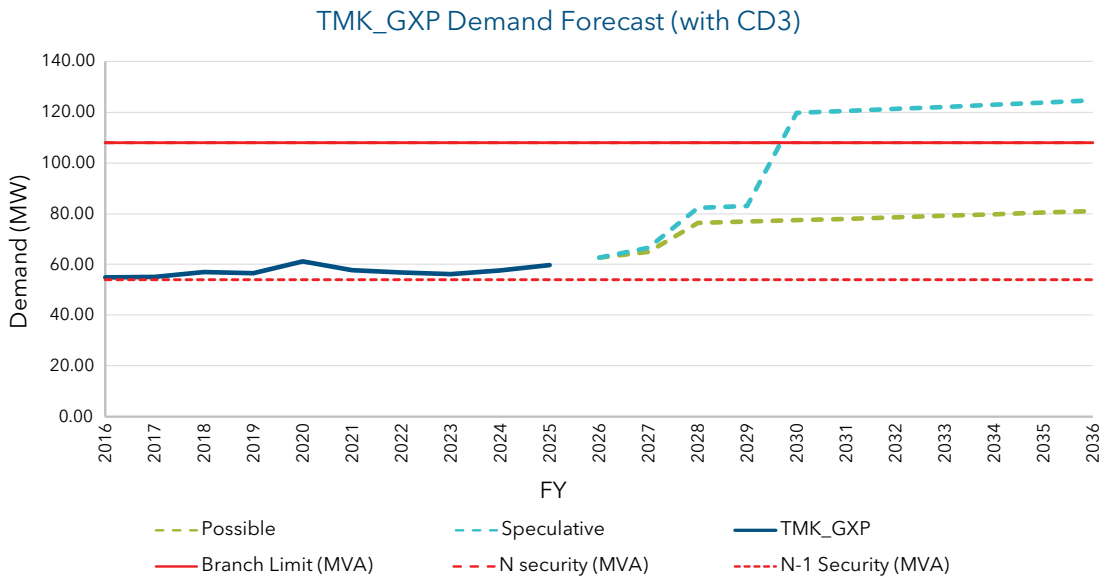
| Zone sub/ load centre | Actual | Target | Comment |
|---|---|---|---|
| **Temuka GXP** | N | N-1 | Solid N-1 security eroded in 2015, and N security prevails during the peak summer dairy season, and N-1 can be maintained for the rest of the year. GXP capacity upgrade is yet to be confirmed in conjunction with proposed GXP in Orari. |
| **Temuka Zone Substation** | N-1 | N-1 | Security target is met for this planning period in accordance with our SoSS. |
| **Clandeboye Zone Substation** | N-1 | N-1 | Target may be breached if major decarbonisation plans are confirmed, at which time options will be investigated to improve security to target level. This most likely be through a new Zone Substation (Clandeboye 3) |
| **Clandeboye 1** | N-1 | N-1 | Security target is met for this planning period in accordance with our SoSS. |

| Zone sub/ load centre | Actual | Target | Comment |
|---|---|---|---|
| **Clandeboye 2** | N-1 | N-1 | Security target is met for this planning period in accordance with our SoSS. |
| **Geraldine Zone Substation** | N | N | Project option analysis is underway to explore security improvements. Restoration of 50% of the lost load in switching time |
| **Rangitata Zone Substation** | 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 GXP demand forecast

The demand forecasts for the Temuka GXP are shown below. It includes expected decarbonisation loads in Clandeboye.

*Figure 34 | Temuka GXP Demand Forecast.*




## Existing and forecast constraints

The Temuka GXP faces emerging pressure from decarbonisation enquiries and large distributed generation proposals. If these developments proceed at scale, the GXP will exceed its capacity. A new GXP at Orari becomes the most economic long-term solution, relieving Temuka while supporting future industrial growth. Under this option, two 110 kV lines would link Orari to Clandeboye, where a new zone substation would convert supply to 33 kV and offload Fonterra Clandeboye from the Temuka GXP. Additional 110 kV or 33 kV lines would then strengthen the connection between Clandeboye and Temuka.

If major decarbonisation loads do not eventuate, investment requirements change. A third transformer at Temuka GXP becomes the more likely option to lift capacity and maintain security of supply. This decision depends heavily on the pathway Fonterra selects. A biomass based solution reduces the need for new transmission and GXP investment, while a full electrification pathway would make a new Orari GXP and associated 110 kV or 33 kV lines both technically and economically appropriate.

A hybrid approach is also possible, where Clandeboye remains supplied from Temuka and only new load is transferred to Orari. In this scenario, both Temuka and Orari would require upgrades. To avoid unnecessary duplication of capital expenditure, we are assessing the option of transferring Geraldine and Rangitata zone substations to the proposed Orari GXP. This would

require new sub transmission lines but may remove the need to expand Temuka GXP and build Orari GXP to its fullest extent.

Alongside traditional network reinforcement, we are evaluating non network options to improve security of supply. A battery energy storage system is being considered to manage the marginal peak season breach at Temuka GXP. We are also assessing the combined effect of battery storage and the 27.7 MW Lodestone solar development, which may help alleviate peak constraints and defer more substantial investment.

## Clandeboye Zone 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. Orari new GXP proposal has been developed to serve this significant additional demand increase in conjunction with building a new double circuit sub-transmission line from Orari to Clandeboye, and new zone substation (Clandeboye 3) in Fonterra premises.

However, due to economic uncertainty and other external factors, the likelihood of this large decarbonisation demand materialising is speculative. Therefore, we are evaluating other options to enhance the capacity and security of supply in Temuka GXP (Refer previous section). Adding a third transformer at the GXP and use of a suitably sized BESS with solar farm are two options currently being considered.

*Figure 35 | Clandeboye Zone Substations Total Demand Forecast.*

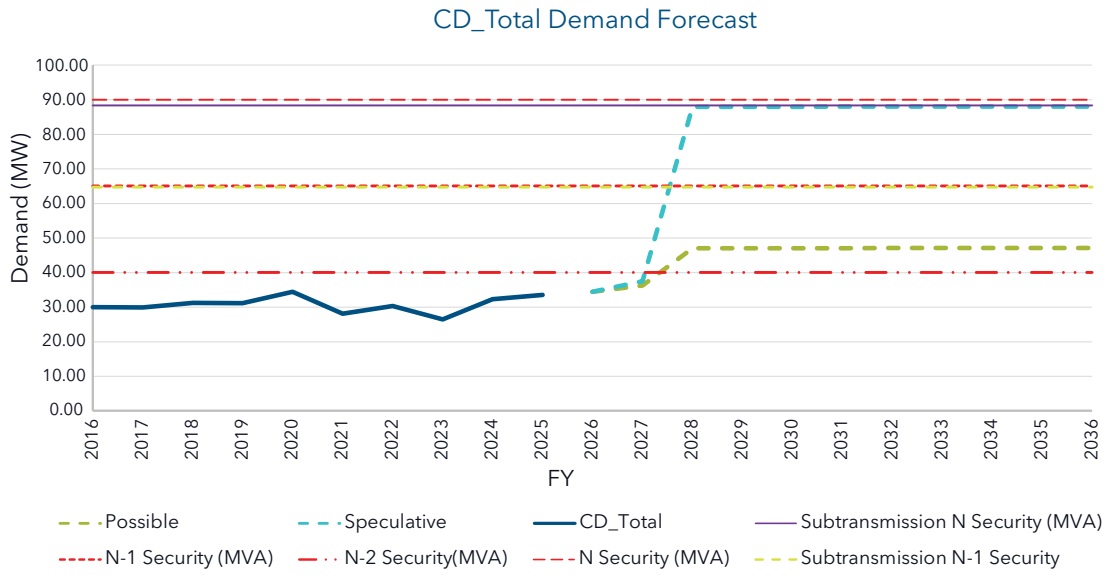
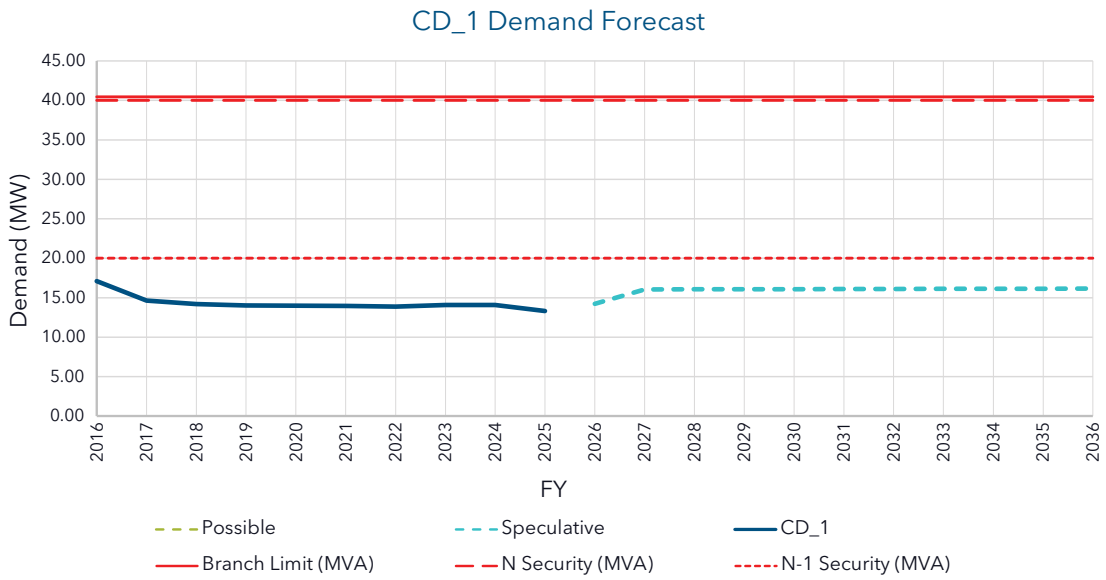
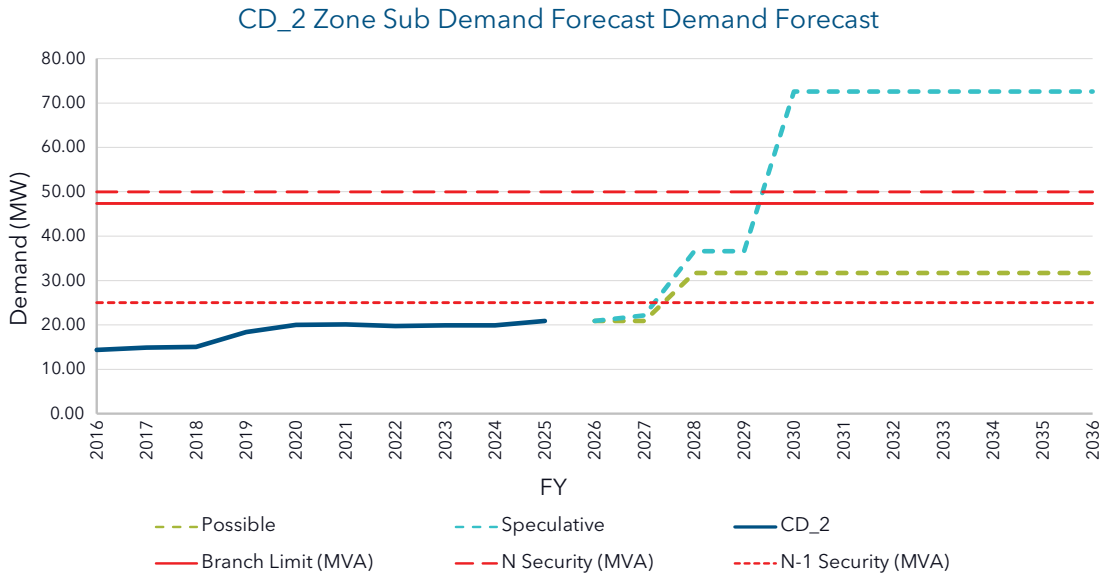


*Figure 36 | Clandeboye Zone Substation 1 Demand Forecast.*




Anticipated decarbonisation load of around 40 MW in Clandeboye has been added to Clandeboye 2 Zone Substation for illustrate the capacity limitations in the existing infrastructure.

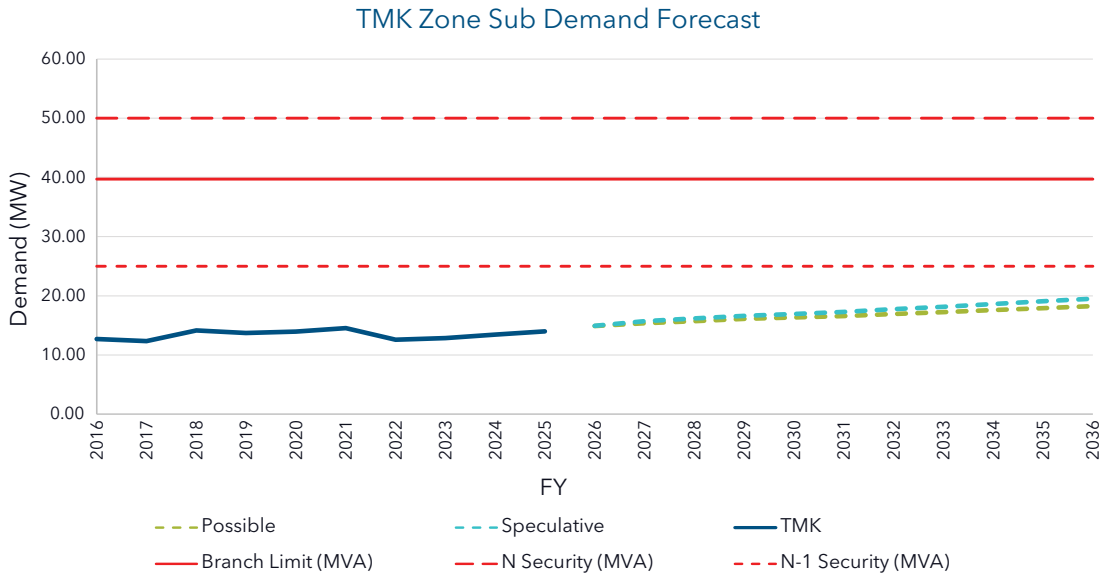
*Figure 37 | Clandeboye Zone Substation 2 Demand Forecast.*



## Temuka Zone Substation

Temuka zone substation 2x25 MVA 33/11kV transformers is in the Temuka GXP premises and supplies to Temuka township and rural areas around the township.

*Figure 38 | Temuka Zone Substation Demand Forecast*



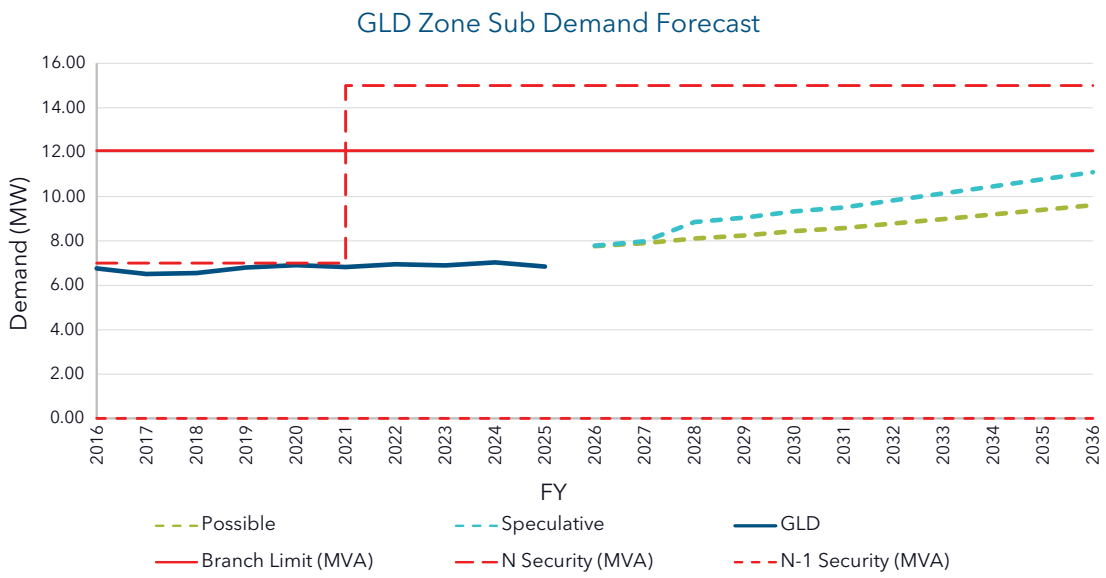

A number of projects are in the pipeline to alleviate downstream constraints on 11kV feeders from Temuka zone substation in the forthcoming years.

## Geraldine Zone Substation

Geraldine zone substation is currently at N security, and according to our current SoS standards, N-( Restoration of 50% of the lost load in switching time) - is the target. We are currently working towards achieving this. Longer term, if Orari new proposal materializes, we plan to bring in new 33kV feeders from Orari and transfer Geraldine load to Orari GXP.

We have observed a few other constraints at 11kV feeder level including the Geraldine township feeder which supplies to the entire Geraldine town. A project to enhance security of supply, reliability and to add capacity by building a new feeder into the township from the zone substation is currently under evaluation.

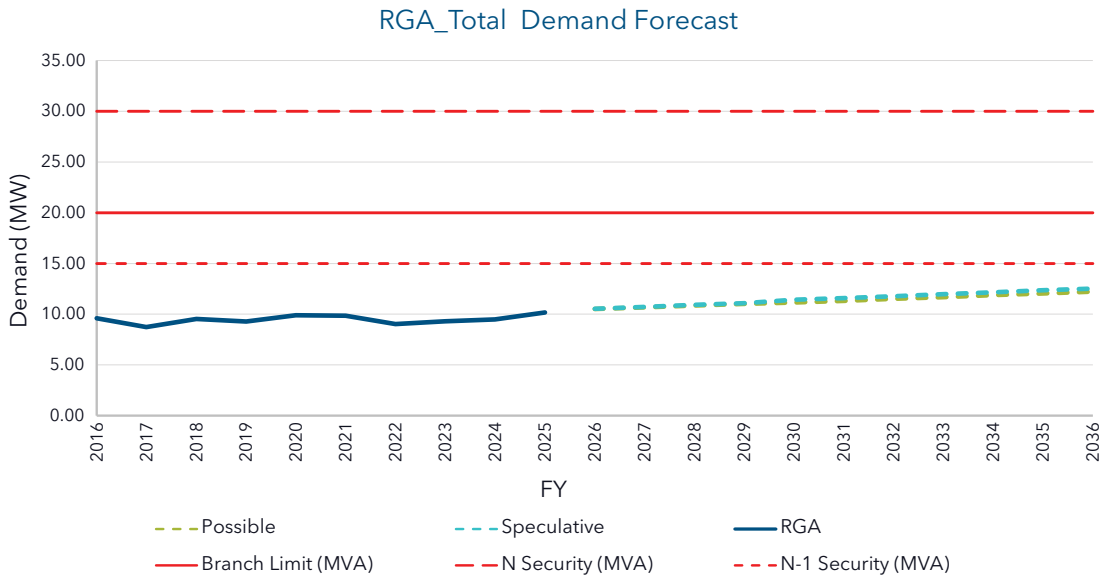
*Figure 39 | Geraldine Zone Substation Demand Forecast.*




## Rangitata Zone Substation

Rangitata zone substation is fed from Temuka GXP via two 33 kV circuits, one is a shared supply to Clandeboye zone substation. The transformers are 2x15 MVA, we do not expect any substantial demand increase in the area during the current planning window. We have identified a capacity constraint due to a contractual limit of 10 MVA on the shared 33kV line to be able for us to maintain N-1 on the incomers to Rangitata zone substation.

*Figure 40 | Rangitata Zone Substation Demand Forecast.*



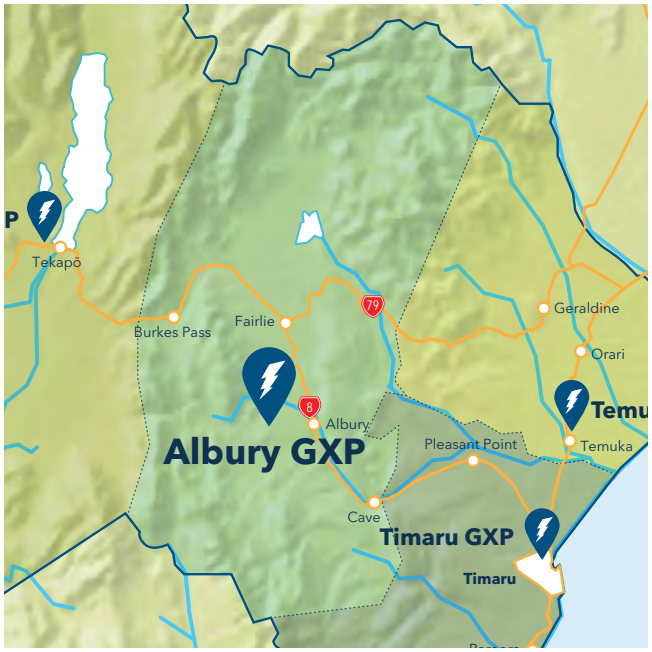
# Albury GXP region

## Overview

The Albury Region is rural with farming the predominant activity. The rural service town of Fairlie is in the Albury GXP region and also services tourists 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.

*Figure 41 | Albury GXP region*




## Security of supply

Table 19 below outlines Albury and Fairlie Substations' SoS.

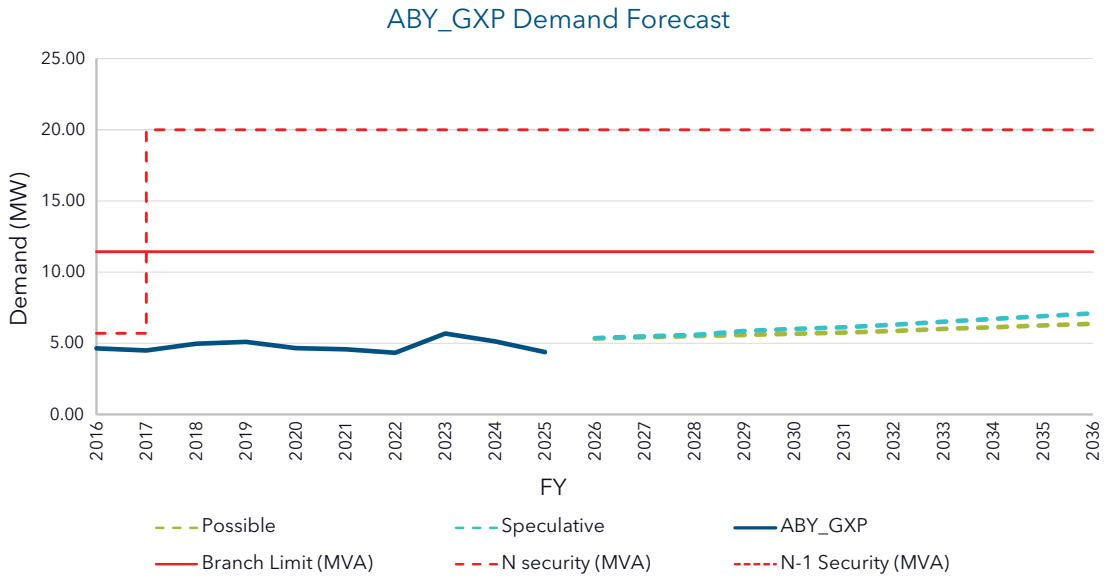
*Table 19 | Albury GXP SoS*

| Zone sub/ load centre | Actual | Target | Comment |
|---|---|---|---|
| **Albury** | N | N | Security target is met for this planning period in accordance with our SoSS.<br>A Transpower mobile substation can be deployed at this GXP. Transpower has evaluated this GXP as 'N security material economic consequence'. |
| **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. |

| Zone sub/ load centre | Actual | Target | Comment |
|---|---|---|---|
| **Fairlie** | N | N- | Limited fault backup to Fairlie Zone Substation and distribution feeders. Restoration of 50% of the lost load in switching time is targeted.<br><br>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 42 | Albury GXP Demand Forecast.*

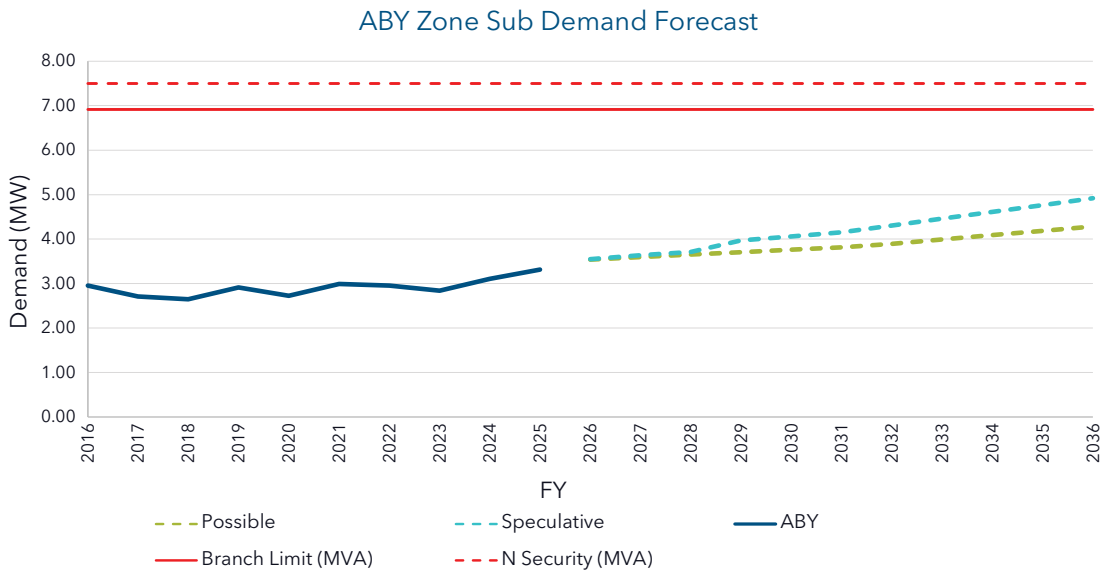



## Existing and forecast constraints

## 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 were 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.

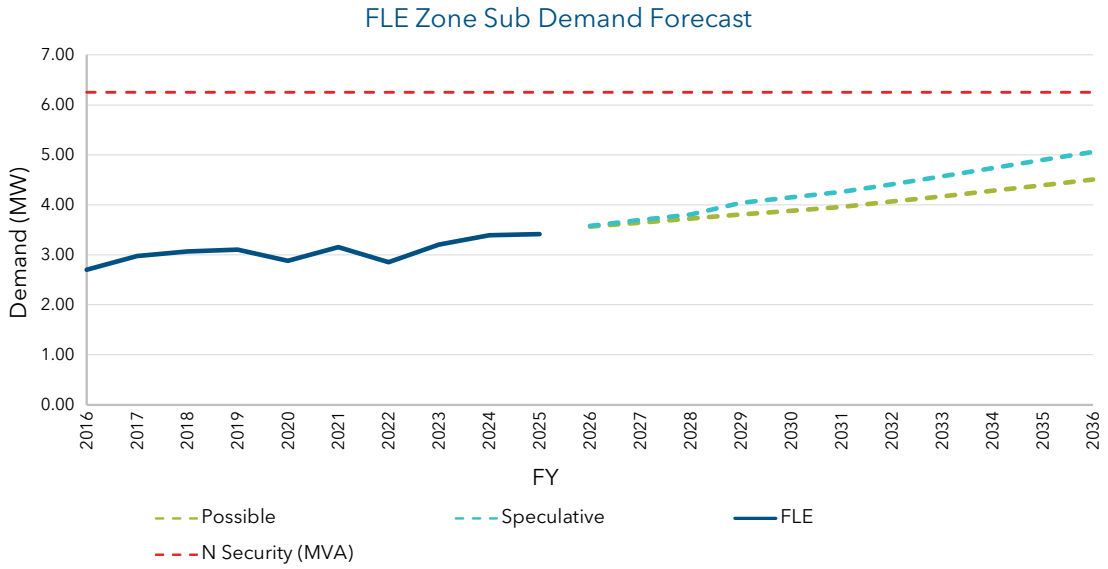
*Figure 43 | Albury Zone Substation Demand Forecast.*




## 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. However, feasibility of this needs to be further investigated.

*Figure 44 | Fairlie Zone Substation Demand Forecast.*




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.

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 large capacity increase is required, the solution could be a 'microgrid' or a full rebuild of the overhead line from Fairlie.

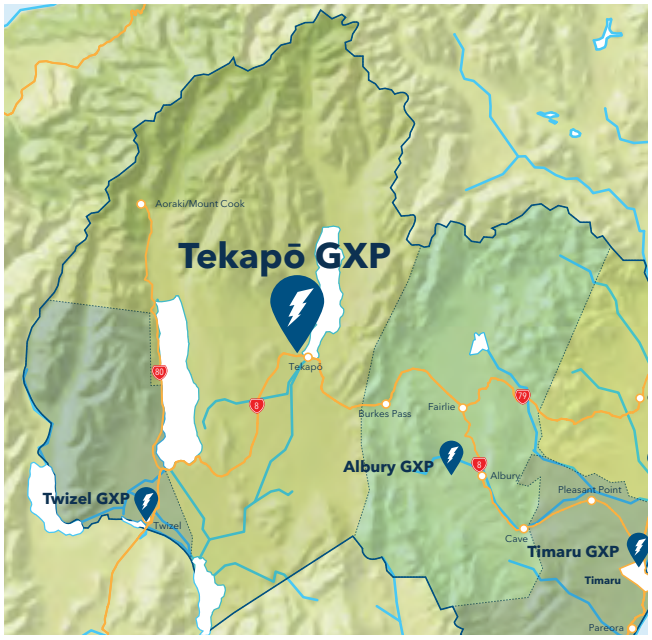
# Tekapo GXP region

## Overview

The Tekapo GXP region is in 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.

Tekapo 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 Tekapo and Lake Pukaki.

*Figure 45 | Tekapo GXP region*




## Security of supply

The Tekapo, Haldon-Lilybank, Old Man Range and Unwin Hut substation security of supply levels are shown in Tabel 20 below:

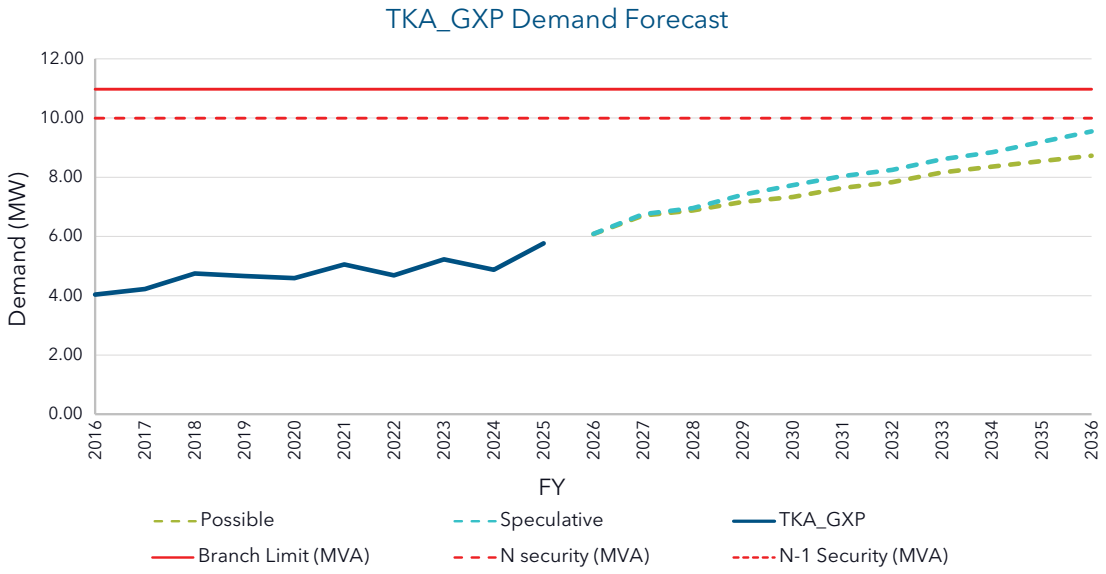
*Table 20 | Tekapo GXP SoS*

| Zone sub/load centre | Actual | Target | Comment |
|---|---|---|---|
| **Tekapo GXP** | N | N-1 | The GXP's target is N-1 in accordance with our SoSS due to its criticality being a popular tourism destination.<br>Transpower's categorisation for Tekapo GXP is "N security material economic consequence". Hydro generator 28 MVA in Tekapo A can provide black start support at 11kV. Transpower can also deploy their mobile substation during planned outages.<br>Tekapo Indoor to Indoor (IDID) conversion of the 11kV switchboard is now complete with spare circuit breakers. |
| **Tekapo-Tekapo Zone Substation** | N | N-1 | N-1 is the desired security level for this sub-transmission circuit up to the Tekapo 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 |
|---|---|---|---|
| **Tekapo Zone Substation** | N | N-1 | N-1 is the desired security level for Tekapo 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. Alternatively, converting incomers to 11kV and the zone substation to a switching station 11kV is also being evaluated. |
| **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. |

## Tekapo Demand Forecast

*Figure 46 | Tekapo GXP Demand Forecast.*




## Existing and forecast constraints

Tekapo zone substation is supplied through a 33kV OH single circuit from Tekapo GXP. The zone substation in Tekapo also has single a transformer of 9/15 MVA 33/11kV and therefore both are at N security. However, Transpower can deploy their mobile substation at the GXP for planned outages, and we too can use our mobile zone substation in the event of an outage. We are also considering procuring generator sets up to 1MW so that those can be deployed to minimize the impact of outages in Tekapo and the rest of Alpine network.

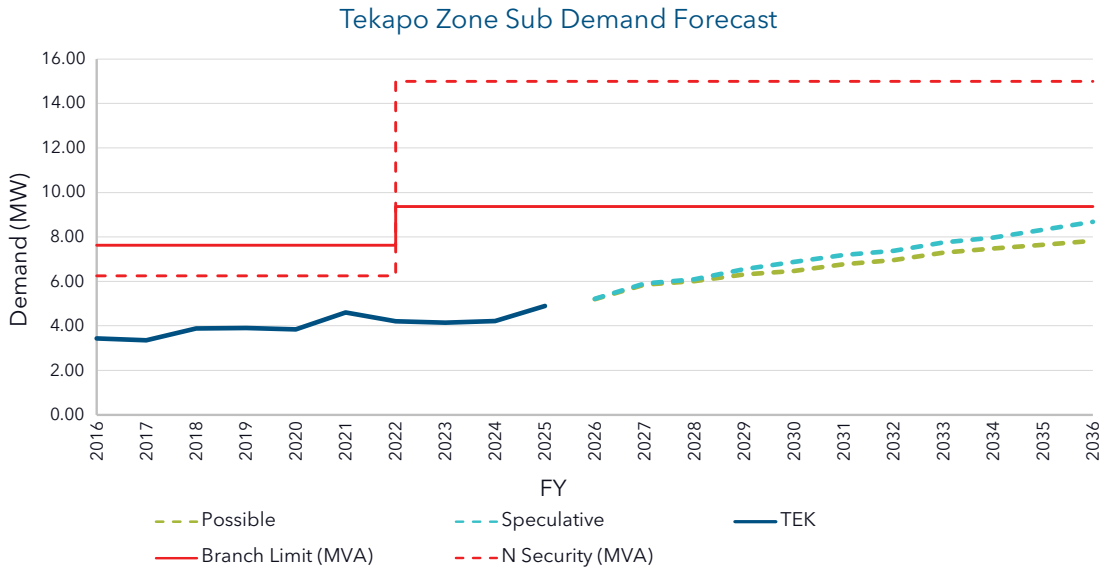
## Tekapo Zone Substation

Tekapo zone substation has a single transformer 9/15MVA with outdoor an indoor 33kV and 11kV switchgear. 11kV feeders from the zone substation supply to Tekapo township, Holden, Lilybank, Godley peaks, Old Man Range and Simons Pass. Tekapo township is popular tourist destination

where a lot of hotels, motels, commercial outlets, and life-style housing. Zone substation demand peaks in winter, but significant tourist arrivals are experienced in summer as well. There is considerable potential for expansion of public EV charging facilities due to its prime location as a tourist attraction overlooking Tekapo lake.

Options are being studied to improve the security of supply in the area by building a second zone substation or constructing high-capacity 11kV circuits into the town and converting the existing zone substation to a 11kV switching station.

*Figure 47 | Tekapo Zone Substation Demand Forecast.*

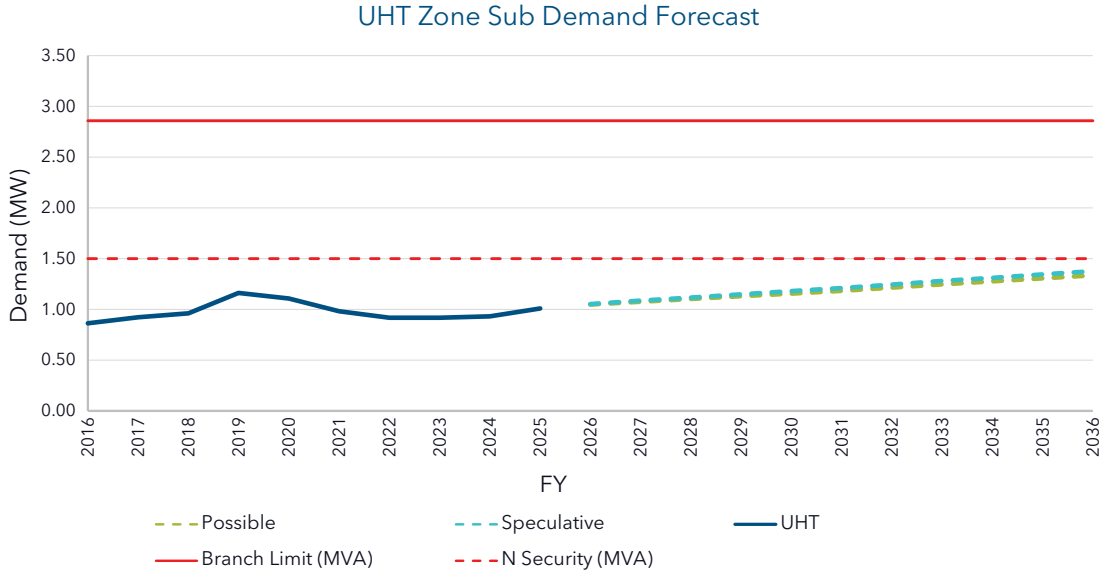



A list of major constraints and the projects identified to alleviate the issues in Tekapo GXP, sub-transmission, zone substation is listed below.

## Unwin Hut upgrade (Mt Cook)

Unwin Hut zone substation 1.5 MVA single transformer, 33/11kV supplies to Mt Cook village, which is a popular tourist destination in South Canterbury. We are currently unaware of any confirmed public EV charger installations in the area, but there could be potential to have public EV chargers in the area, so we closely monitoring the situation to implement mitigatory measures.

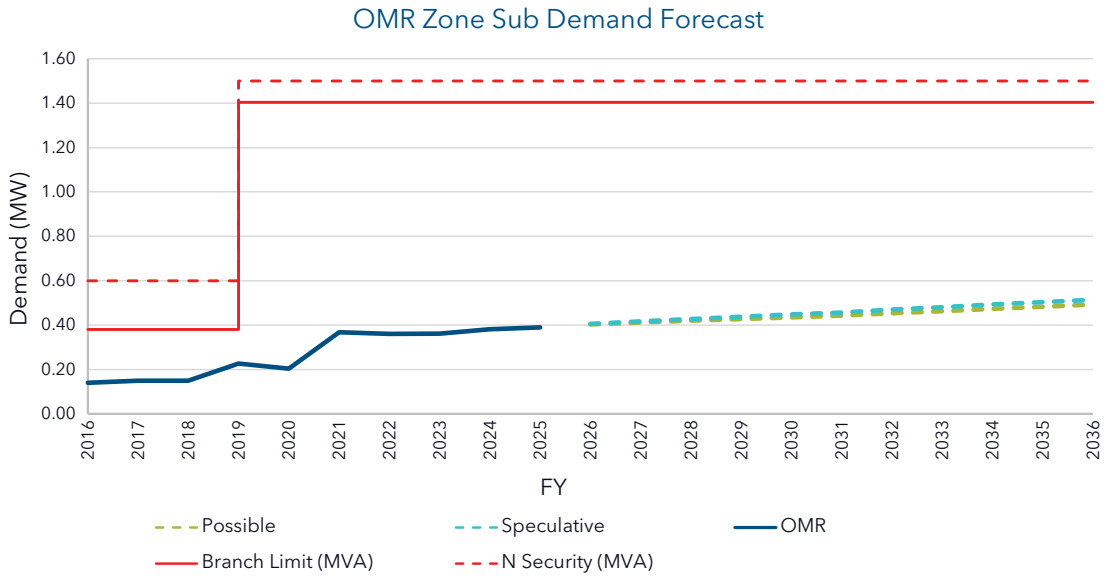
*Figure 48| Unwin Hut Zone Substation Demand Forecast.*



## Old Man Range upgrade

This is a 11/22kV 1.5 MVA transformer supplying Old Man Range and Simons Pass, and this is supplied from a 11kV feeder from Tekapo zone substation.

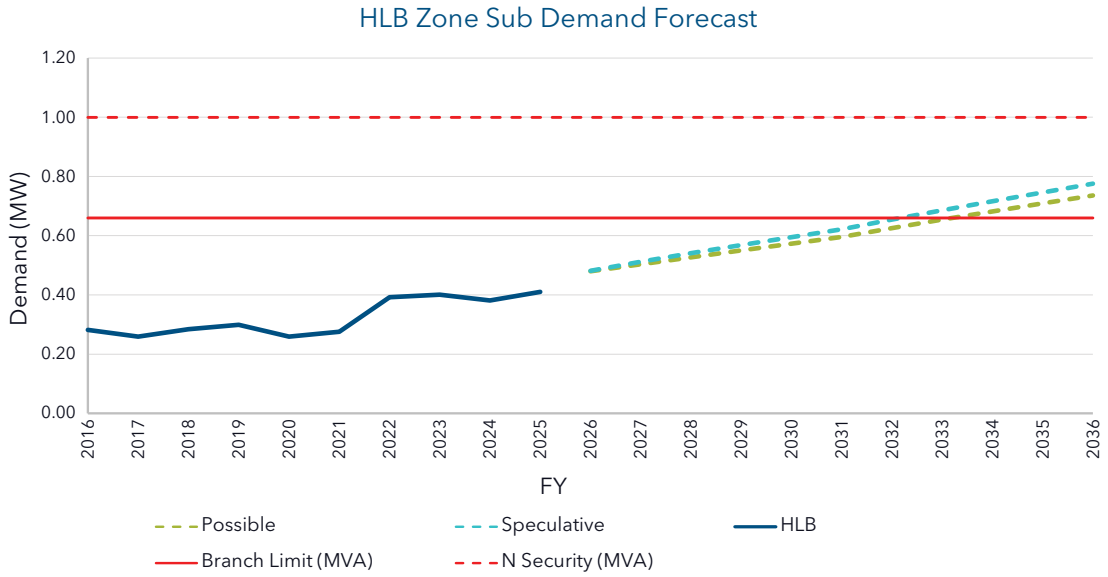
*Figure 49 | Old Man Range Zone Substation Demand Forecast.*




## Haldon-Lilybank Substation

We do not expect to see any substantial growth in this area. However, based on the organic growth forecast, demand is likely to reach the branch limit by 2031/2032. We are closely monitoring the situation to formulate mitigatory measures.

*Figure 50 | Haldon-Lilybank Substation Demand Forecast.*



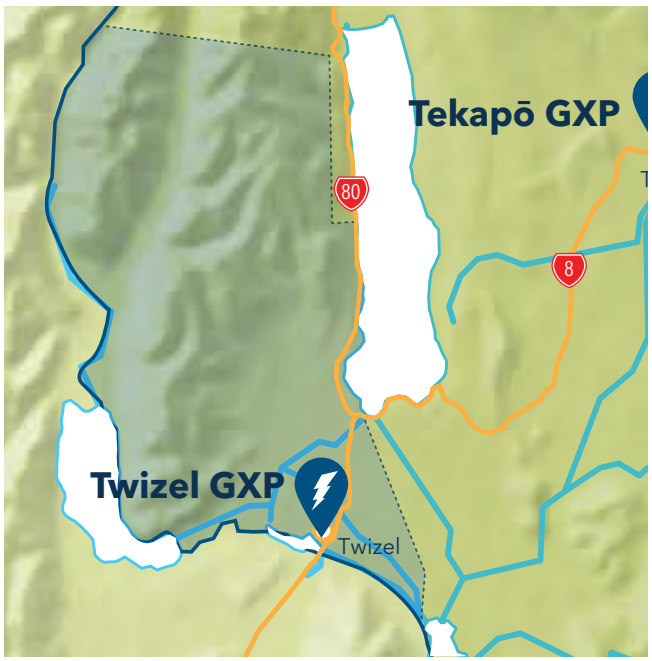
# Twizel GXP region

## 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.

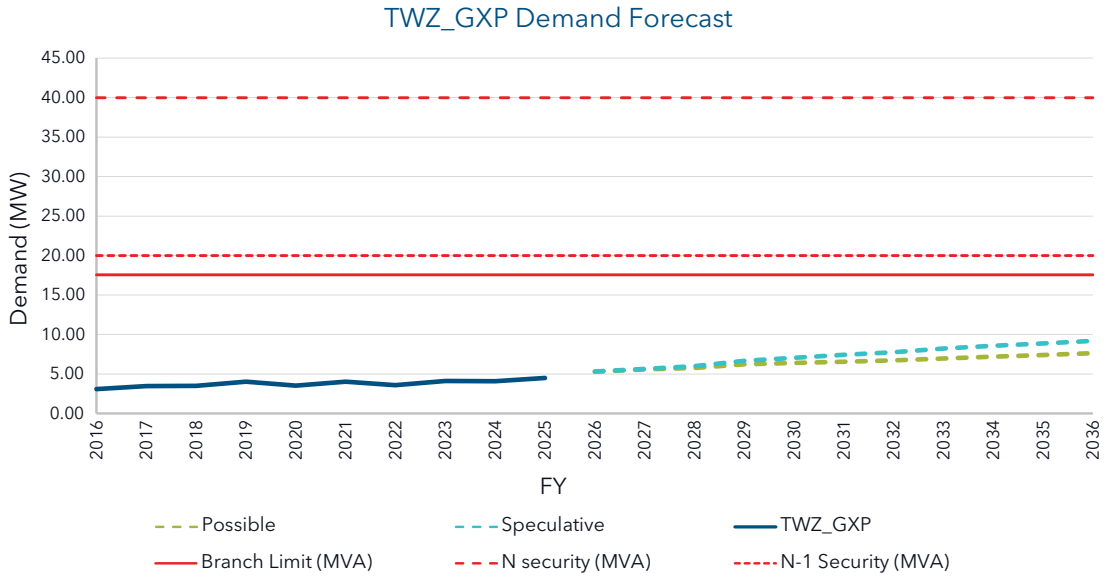
Meridian Energy has generation assets at Lake Ohau, Lake Ruataniwha, and Lake Benmore in the region.

*Figure 51 | Twizel GXP region*




## Twizel demand forecast

*Figure 52 | Twizel GXP Demand Forecast*



### Security of supply

Table 22 below outlines the Twizel region's SoS.

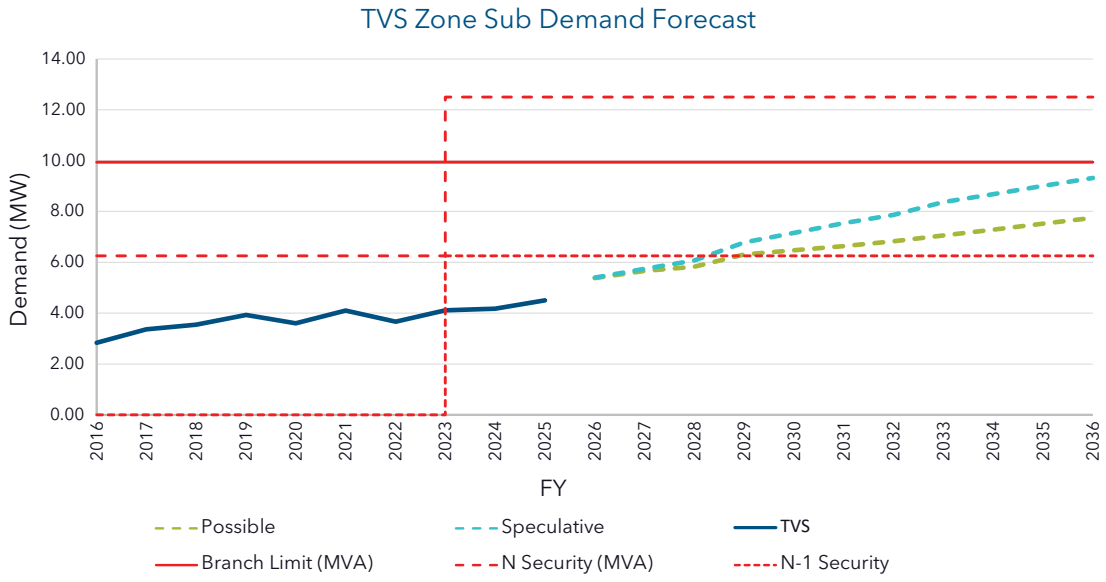
*Table 22 | Twizel GXP SoS*

| Zone sub/ load centre | Actual | Target | Comment |
|---|---|---|---|
| **Twizel GXP** | N-1 SW | N-1 | Transpower has evaluated this GXP as N-1 security material economic consequence (Refer Transpower IPP Determination 2025) |
| **Twizel GXP -Twizel zone sub. sub-transmission** | N | N-1 | Does not meet our SoSS criteria. |
| **Twizel Village Zone Substation** | N-1 | N-1 SW | SoSS is met for the forecasting period |

### 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. 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 53 | Twizel Village Zone Substation Demand Forecast*




## 6.4. Enabling flexibility and participation

Historically, LV networks were designed for stable, passive household loads with one-way power flow. However, the increasing uptake of technologies such as electric vehicles (EVs) and distributed generation (DG) now places greater demand on the LV network and introduces two-way power flows. Our LV network represents a significant portion of our assets and is the primary point of connection for residential customers. Enhancing visibility and control of the LV network is increasingly important to maintain service levels and support evolving customer energy choices.

Our Network Development Plans (NDPs) identify the risks and opportunities arising from the growing penetration of DG and EVs across our region. However, much of our LV infrastructure has

seen minimal upgrades over its life, which may limit our ability to accommodate these emerging technologies and changing customer needs. This may require a shift away from traditional planning and investment approaches.

To enhance visibility and control of our LV network, we are leveraging SmartCo's Hiko platform. Hiko provides near real-time monitoring of LV network performance by aggregating and analysing smart meter data across the region. This platform enables more accurate identification of voltage excursions, unbalanced phases, and emerging load patterns at a granular level.

By integrating LV visibility into our network planning and operational processes, we are improving our ability to:

- Detect and respond to LV network issues proactively
- Support the integration of distributed energy resources (DER), including rooftop solar and EV chargers
- Inform the deployment of targeted non-network and asset-based solutions
- Improve forecasting accuracy for future investment planning

The insights provided by the platform allow us to shift from reactive to data-driven, proactive management of the LV network. We continuously working to improve the functionality, accuracy, and reporting capabilities of the tool to support our strategy to manage the LV network.

We have our focus on both non-network and network solutions to effectively manage our LV network. Under non-network solutions, we open for:

- Phase balancing – Distributing customer loads evenly across the three phases of an LV feeder.
- Demand-side management – Techniques such as ripple control, time-of-use pricing, and smart meter-based EV charger control to help manage peak demand.
- Energy storage – Supporting household-level or network-scale battery storage to improve resilience and reduce peak loading.
- Network or Asset-Based Solutions
- LV regulators at strategic points
- Distributed battery systems
- Reconfiguration of LV circuits to reduce length and improve voltage control
- On-load tap-changing distribution transformers
- LV conductor upgrades to increase capacity

## Future LV roadmap

Improved LV network visibility, enabled by increased smart meter and LV monitoring, will allow us to observe electricity use in near real-time at the household level. This enhanced insight will help us detect changes in network activity and support the delivery of more flexible, customer-focused energy solutions. We are currently working with Smartco's Hiko platform for our LV network studies. Some of the ongoing activities include:

- Improving accuracy of loading estimations
- Improving accuracy of DG hosting capacity calculations
- Demand management using smart meters to alleviate peak time constraints
- Reporting on PQ data, transformer unbalance and utilisation
- Voltage quality monitoring
- PV compliance monitoring

As we deepen our analysis of this data, we will gain a clearer understanding of baseline LV demand and track how it evolves with the uptake of technologies such as EVs, solar PV, battery storage, and energy sharing. Smart meter insights will also provide improved visibility of power quality issues affecting LV customers.

This data-driven approach will enhance our demand forecasting and maintenance planning processes, guiding future investment decisions, and supporting the development of a long-term LV roadmap for a smarter, more resilient network.

# 7. Strengthening our network

Delivering a safe, reliable, and future-ready electricity network requires targeted investment in the assets and systems that underpin our operations. This chapter outlines Alpine Energy's approach to strengthening the network through planned investment, lifecycle management, and fleet stewardship. It supports the strategic investment theme of the Asset Management Plan by aligning network development with our long-term goals of resilience, efficiency, and customer service.

The initiatives described in this chapter reflect our commitment to maintaining service levels, managing risk, and adapting to emerging challenges such as climate change, decentralised energy, and evolving customer expectations. Through a combination of network-wide management practices and fleet-specific strategies, we aim to optimise asset performance, extend useful life, and ensure the network remains capable of meeting future demand.

This chapter includes a summary of material investment projects, our network management approach, and an overview of how we manage key asset fleets across the distribution system.

## 7.1. Investment summary

### Summary of 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.

*Figure 53 | Summary of material network projects*

| Project | Year | Primary Driver |
|---|---|---|
| Grasmere sub transmission upgrade | FY27-FY30 | Reliability |
| Routine Maintenance Defect Resolution | Annual | Reliability |
| Urgent Overhead Line Response | Annual | Reliability |
| RMUs Attending Sub-Transmission Circuits | FY27 | Safety |
| Reducing the Risk posed by Load Break Switch Flashovers | FY27, FY28 | Safety |
| Facilitate Solar Farms | FY27 - FY28, FY30 - FY31 | Growth |
| Timaru Pages Road to Centennial Park Connection | FY27 - FY28 | Safety |
| Temuka East Asset Renewal | FY27 | Reliability |
| Geraldine Feeder Upgrade | FY28 - FY29 | Reliability |
| Grants Road Timaru Feeder Capacity Increase | FY30 - FY31 | Reliability |
| Hunt Street Timaru Switching Station Rebuild | FY32 - FY33 | Reliability |
| Temuka Feeder Capacity Upgrade | FY27 | Reliability |
| Timaru GXP Feeder Reconfiguration | FY30, FY34 | Reliability |
| TMK Temuka Security of Supply Improvements | FY33–FY36 | Reliability |
| Studholme Ripple Plant Upgrade | FY28 | Reliability |
| Second Pleasant Point Transformer | FY31 | Resilience |
| Rebuilding Tekapo Zone Substation | FY32 | Reliability |
| Replace poor condition transformer | FY32 | Reliability |
| Replace Fairlie Power Transformer. | FY32 | Reliability |
| Timaru Airport Electrification Cabling | FY32 | Growth |
| Upgrade Tekapo GXP | FY33 | Growth |
| Timaru GXP Feeder Reconfiguration | FY30, FY34 | Growth |
| Mitigating Tekapo Outages | FY36 | Reliability |
| Fairlie LV Undergrounding | FY27, FY28 | Resilience |
| Pukaki Downs Line Renewal | FY31 | Reliability |
| Underground Substation Relocation Programme | FY27 – FY34 | Reliability |
| Timaru GXP Ripple Plant Replacement | FY31 | Reliability |
| TMK Temuka Security of Supply Improvements | FY33–FY36 | Growth |
| Tekapo Bridge Cable Crossing | FY29, FY31 - FY32 | Reliability |
| Growth Driven Cable Capacity Upgrade | FY30-FY36 | Growth |
| Timaru Port Sub Transmission Ducting | FY34 | Reliability |
| Washdyke Cable Upgrade Provisions | Annual | Growth |
| Rebuild Pleasant Point Substation | FY32 – FY33 | Reliability |
| Convert North Street Substation to 33kV | FY33 – FY36 | Growth |
| Establish a second Tekapo substation | FY33 - FY34 | Growth |
| Twizel Sub N-1 constraint | FY33 – FY36 | Growth |
| Build new switching substation | FY34 – FY36 | Growth |
| Build new Washdyke 33kV Substation | FY34 – FY36 | Growth |
| New Port Switching Station | FY34 – FY36 | Growth |
| Tekapo GXP security. | FY34 – FY36 | Reliability |
| Improving Twizel Substation Security of Supply | FY35 – FY36 | Reliability |
| Install second sub-transmission circuit cable between to Twizel substation | FY35 – FY36 | Reliability |
| Install supply cable from North Street Substation and new switching substation. | FY35 – FY36 | Reliability |
| Port Distribution Feeder Upgrades | FY35 – FY36 | Reliability |

## 7.2. Network management approach

This subsection outlines our approach network management approach. It covers the 'operate', 'maintain' and 'refurbish or dispose' stages of our asset management lifecycle framework, outlined in section 5.1

*Figure 54 | Asset management lifecycle*


AHI (Asset Health Indicators) provide a straightforward way of expressing where an asset sits in its life cycle and how well it can continue to deliver safe, compliant, and cost-effective service. We apply the five step AHI framework developed by the EEA (Electricity Engineers Association), using age as the determining factor. Under this approach, H5 describes assets in near new condition, H4 reflects those in normal service, H3 and H2 signal progressive movement toward end of life, and H1 identifies assets that have reached the point where replacement is advised.

*Figure 55 | Asset health indicator age thresholds*

| AHI | Age Parameter |
|---|---|
| H5 | New |
| | 50% toward onset of unreliability |
| H4 | |
| | Onset of unreliability |
| H3 | |
| | 50% toward Maximum practical life |
| H2 | |
| | Maximum practical life |
| H1 | Exceeding maximum practical life |

For this AMP we apply the AHI in a deliberately simple, age-based manner. Condition findings and wider risk drivers are not yet integrated into the index. Assets younger than half of the onset of unreliability age sit in H5, those between this point and the onset of unreliability age fall into H4, those between the onset of unreliability and the midpoint to maximum practical life are assigned H3, those between that midpoint and maximum practical life sit in H2, and any asset at or beyond its maximum practical life is classified as H1.

The Asset Health Indicator levels H1 to H5 are distinct from the planning horizons used elsewhere in this AMP. Horizon One, Horizon Two, and Horizon Three describe when and how we intend to invest, particularly in digital capability and network development. The Asset Health Indicator describes the life cycle stage of specific assets and fleets, and is one of the inputs we use when we decide how to prioritise renewal activity within those broader horizons.

## 7.3. Network-wide operations

We operate and maintain our network assets with the objective of delivering safe, reliable, and efficient electricity to our customers at all times. This requires coordinated management of network control, maintenance activities, and outage restoration, supported by systems that enable real-time visibility and control across our network.

### Network control

The network control function ensures a continuous and safe supply of electricity, operating 24 hours a day, seven days a week. From our Control Centre, trained controllers monitor the status and load of the network in real time, using this information to make informed decisions on both planned and unplanned switching. These activities allow sections of the network to be taken out of service for maintenance or repairs without unnecessary disruption to other customers. Controllers also manage controllable load in accordance with retailer contracts, balancing peak demand on the network while maintaining security of supply. This function extends to both high-voltage and low-voltage assets.

### Control centre

The Control Centre also undertakes the dispatch function, directing field crews to carry out work needed to maintain or restore supply. Communication with customers, field crews and contractors is maintained throughout the process to ensure coordinated and timely responses. In periods of elevated fire risk, the team works closely with the rural fire service to disable auto-reclose functions on pole-mounted reclosers, reducing the chance of re-ignition from faults.

### Outage management

Network controllers manage outage-related calls, coordinate restoration efforts, and keep customers informed. They track interruptions, update the outage portal on our website, and maintain the interactive voice response system with accurate information for both planned and unplanned outages.

### Future opportunities

We are progressing initiatives to enhance network control, operational resilience, and readiness for emerging network challenges, including:

- Increasing remote control capability for field devices, including reclosers, voltage regulation equipment, and telemetry-enabled fault passage indicators, to improve responsiveness during both planned and unplanned events.
- Expanding SCADA functionality to include electronic switching preparation, mobile access for field crews, and automated load restoration, enabling faster and safer restoration of supply.

- Integrating SCADA with GIS, ERP, and CRM platforms to provide richer situational awareness, improve asset data management, and support more flexible and customer-focused operations.
- Assessing our readiness for advanced distribution management and system operation capabilities to increase network automation and operating options.

## Release planning

Release planning, managed by the Control Centre, is the process of isolating and releasing sections of the network so that work can be carried out safely. Requests to access our network assets are processed and coordinated to minimise both the frequency and duration of outages.

## Switching

Switching is undertaken to disconnect sections of the network for safety isolation, to enable maintenance or new connection works, or to restore electricity supply following a network fault. Two principal switching methods are used. Remote switching is performed by the Control Centre through the SCADA system, while field switching is carried out by our field staff under the direction of the Control Centre. Switching plans are prepared and authorised in the Control Centre before being issued to our field staff. All major zone substations and around seventy-five percent of our reclosers are remotely controllable.

## System interruptions and emergencies

System Interruptions and Emergencies (SIE) cover reactive interventions in response to unplanned network events. These include:

- First response: the attendance of a fault person to assess the cause of an interruption, potential loss of supply, or safety risk. They evaluate the fault and may undertake switching or isolate a section of line to make it safe or prevent a wider outage.
- Fault restoration: undertaken by the fault person and may involve switching, fuse replacement, or minor component repairs to restore electricity supply.
- Second response: carried out when supply has been restored but further work or equipment is needed to return the network to its normal state.

SIE work is prioritised and dispatched by the Control Centre, with all physical work undertaken by our field crew. While proactive planning for SIE is limited, sufficient resources are maintained on standby to respond to network faults. Response is prioritised based on our need to manage safety risks the need to maintain service levels to our customers.

SIE work volumes are influenced by asset condition, weather and environmental conditions, and our protection philosophies. The high-level objectives for our SIE portfolio are detailed below.

*Table 23 | SIE portfolio objectives*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Reduce fault response times to minimise risks to public safety.<br>Prioritise safety-driven faults and ensure a safe power supply that meets customer needs. |
| **Customer service levels** | Minimise outage events and durations to meet regulatory reliability requirements and support customers' operations. |
| **Cost** | Explore alternative technologies to reduce the cost of reactive work and improve response times. |
| **Community** | Minimise disruption to landowners during fault response and reduce restoration times. |
| **Asset management capability** | At the planning stage of an asset's lifecycle, use asset capacity rating information to enhance load limits allow for back-feeding during faults. Support customers during asset failures through alternative supply routes.<br>Support customers' during asset failure events through alternative supply routes. |

To achieve these objectives, we follow key operational practices:

- Safety culture: maintain a strong health and safety culture, supported by regular field safety to ensure a consistent approach to safety at work
- Public awareness: educate the public through regular engagement and promote public awareness of the risk and dangers inherent in electricity networks
- Resource management: ensure sufficient resources, equipment, and spare materials are available to respond to SIE requirements.
- Systems enhancements: enhance systems and tools available to the Control Centre, including communication systems, SCADA, and GIS, to optimise network operations and decision-making.

Costs incurred in operating the network, for capital projects, are allocated to the relevant project rather than recorded as SIE expenditure. SIE expenditure applies specifically to fault response calls.

## Future network-wide operations improvements

We are advancing a programme of operational system enhancements designed to strengthen network resilience, improve responsiveness, and streamline day-to-day activities. These developments will enhance safety, reduce operational risk, and enable faster, data-driven decision-making.

- Field automation: We plan to extend automation to more field devices, such as reclosers, remotely controlled voltage regulation units, and fault passage indicators with telemetry. These upgrades will support faster and safer responses during planned work and unplanned events.
- Field mobility and digital access: Field teams will have mobile access to detailed asset data, technical specifications, work schedules, and maintenance histories, enabling informed decision-making and efficient task completion on site.
- Enhanced mobile field data collection: We are upgrading our existing field data capture platform to improve usability, speed, and integration with other operational systems. This will allow field staff to collect richer data, attach imagery, and synchronise updates more quickly, reducing delays between inspections and system records.

- Advanced inspection technologies: We will expand the use of drone-assisted inspections for both planned and unplanned work, particularly in challenging or hazardous environments. This will improve data accuracy and speed while reducing health and safety risks.
- Advanced workflow automation: We are expanding the use of automated workflow tools to further standardise procedures, reduce manual hand-offs, and improve traceability. This will enable processes to be adapted quickly in response to operational changes or emerging needs.
- Upgraded operational planning environment: Our project planning and scheduling capability is being enhanced with a consolidated view of operational work, resource allocation, and interdependencies. This will strengthen coordination across teams and improve transparency of delivery progress.
- Enterprise system replacement: We are replacing our core enterprise resource platform with a more flexible, integrated solution. This will improve interoperability between corporate and operational systems, provide better reporting capability, and support mobile and remote working environments.
- Modernised geospatial systems: We are upgrading our mapping and spatial analysis systems to improve accuracy, integrate advanced network modelling, and allow seamless data exchange with asset management and operational platforms. This will support both long-term planning and real-time operational decisions.
- Communications network upgrades: We will continue the rollout of digital mobile radio, extending coverage and improving the reliability of communication links. These upgrades will improve worker safety, support coordinated fault response, and enhance real-time operational control.
- Continuous improvement and capability building: We will embed processes for reviewing operational performance, sharing lessons learned, and adopting targeted capability-building initiatives. These will ensure staff, systems, and procedures adapt effectively to new technology, changing risk profiles, and customer expectations.

## Network maintenance

Maintenance underpins the safety and reliability of our network assets throughout their lifecycle, from commissioning through to disposal. Our maintenance strategies thus evolves as asset condition and performance requirements change over time. Our maintenance approach ensures alignment with operational security needs, safety standards, regulatory compliance, sustainability goals, and cost efficiency, driven by the requirements of our customers, stakeholders, and regulators.

We manage the network through a suite of maintenance activities, including:

- Monitoring and managing the deterioration of assets over time
- Restoring asset condition in response to defects or failures
- Implementing modifications to enhance performance and reliability

## Routine and corrective maintenance

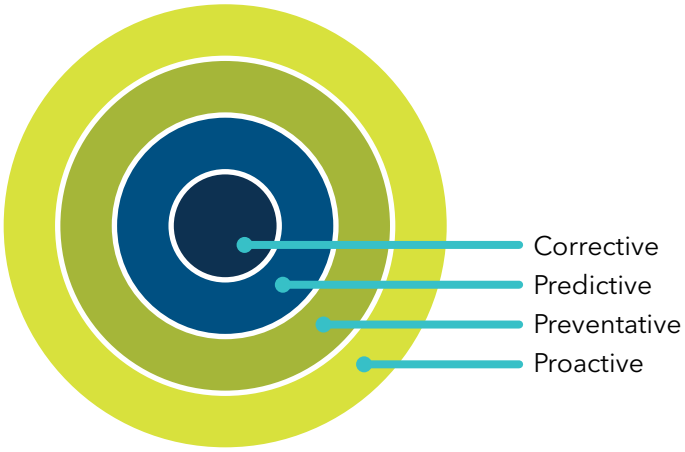
Our field crews execute routine maintenance activities to keep our assets in working order and proactively manage failure risk. We also respond to unplanned defects through corrective maintenance. We classify routine maintenance into four distinct work types:

- Preventive: Scheduled servicing or inspections designed to prevent failure and assess condition, supporting our wider asset management system. Activities include inspections (such as checks and testing), condition assessments, and servicing (cleaning, adjustment, fastening, painting).
- Corrective: Maintenance initiated by unforeseen damage, degradation, or failure, typically

identified during preventive inspections or in response to a fault. Activities include fault restoration, repairs, and safety-related inspections.

- Predictive: Driven by condition-based monitoring, including techniques such as thermographic imaging, to anticipate and address vulnerabilities before failure occurs. This improves network resilience to climate-driven events like storms, floods, and subsidence.
- Proactive: Preventive improvements initiated through formal reliability or engineering analysis, including asset modifications or modernisation to reduce risk or improve performance.

*Figure 56 | Routine maintenance classifications*




## Maintenance projects

Where multiple assets exhibit similar condition issues, we plan maintenance as formal projects comprising small-scale repairs or component replacements. Unlike refurbishment, which extends asset life, these projects restore assets to an acceptable condition without extending their design life. They are scheduled and budgeted in advance, ensuring efficient delivery through structured planning.

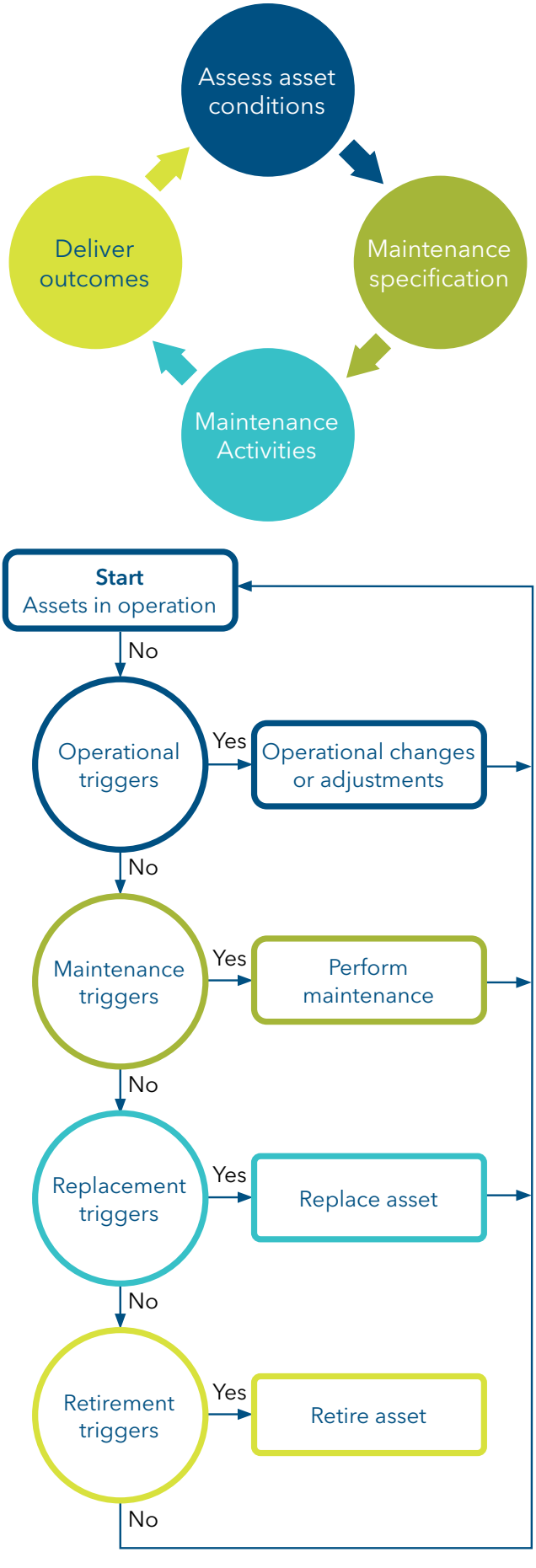
## Maintenance activities

We structure maintenance delivery into two core stages:

- Maintenance specification – Involves defining the maintenance tasks to be carried out, the quality standards to be met, and the resources, materials, and skills required. It is informed by analysis of asset condition and performance data, reliability engineering, and supply chain practices, with support from the Asset Lifecycle team.
- Maintenance delivery – Executing maintenance work by qualified personnel, carried out under a structured plan. It includes medium term programme planning as well as detailed scheduling of the work scope, allocation of resources, and coordination of access arrangements for each task.

These stages form a continuous improvement cycle:

*Figure 57 | Maintenance lifecycle*



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

*Table 24 | Maintenance objectives*

| Asset management objective | Portfolio objective |
|---|---|
| **Public safety & environment** | Ensure all work is carried out safely, without risk to staff, contractors, or the public. |
| **Service levels** | Minimise customer outages during planned maintenance and consolidate work, where possible, to single outages. |
| **Cost** | Maintain cost efficiency through coordinating scoped work, regular budget review, and frequent cost-to-budget comparison. |
| **Community** | Notify customers promptly of planned outages and minimise disruption to traffic and local activity. |
| **Asset management capability** | Leverage our EAM system to record asset condition, schedule asset-type tasks, and coordinate work across geographic areas. |

## Vegetation management

Vegetation management ensures that overhead lines remain clear of obstructions, reducing the risk of vegetation-related outages and supporting our reliability targets, particularly SAIDI and SAIFI. Our vegetation management activities include:

- Conducting periodic surveys to assess whether tree trimming is required.
- Coordinating liaisons with landowners to identify trees that need trimming or removal.
- Performing tree trimming and removals as needed.

We manage vegetation using a cyclical approach, informed by risk and environmental context, to maintain safety, service reliability, and community well-being. This approach recognises the impact of changing weather patterns and tree growth rates on our operating environment.

*Table 25 | Vegetation objectives*

| Portfolio Objectives | |
|---|---|
| **Safety & environment** | Ensure overhead conductors remain clear of vegetation to avoid hazards. |
| **Reliability** | Minimise vegetation-related interruptions to maintain network performance. |
| **Cost-efficiency** | Implement risk-informed cycles to avoid unnecessary trimming while addressing high-risk areas. |
| **Community and engagement** | Work collaboratively with landowners and provide timely notifications of planned works. |
| **Operational agility** | Use data on vegetation, terrain, and outage history to guide proactive trimming cycles reflective of evolving conditions. |

To achieve these objectives, we follow a set of operational guidelines that support reliability, safety, and community engagement:

- Cyclical schedules: Maintain routine vegetation maintenance cycles across the network to protect line clearances, improve reliability, and strengthen resilience.
- Risk-based proactive approach: Conduct regular surveys and inspections to identify encroachment and high-risk tree hazards, providing practical solutions and guidance to tree owners and contractors.

- Contractor engagement: Work closely with approved contractors to ensure compliance with health and safety requirements and adherence to relevant industry regulations, including applicable codes of practice and the "Safety Manual – Electricity Industry".
- Public awareness: Promote public understanding of vegetation risks near power lines by sharing information on safety, the risk of unauthorised tree trimming, planting guidelines, and the responsibilities of tree owners.
- Record enhancements: Strengthen vegetation data records to pinpoint recurring problem areas, support the scheduling of maintenance activities, and improve network resilience.

## Future opportunities

The evolving demands of vegetation management, driven by changing climate, growth pressures, and regulatory expectations, mean our operating expenditures must continually deliver value. We are embracing data-driven technologies and improved processes to ensure efficient, targeted, and resilient management of vegetation-related risks.

- Enhanced mobile field data collection: Our existing vegetation inspection platform will be upgraded to improve usability, speed, and integration with asset and operational systems. Field staff will be able to capture richer data, including high-quality imagery, and synchronise updates more quickly. This will shorten the time between field inspections and follow-up action.
- Advanced inspection technologies: We will continue to expand the use of drone-assisted and aerial inspections for both routine vegetation surveys and reactive work. These methods already improve coverage, enhance safety for field teams, and provide more accurate assessments in areas that are difficult or hazardous to access.
- Upgraded vegetation planning environment: Our planning tools will be enhanced to provide a consolidated view of vegetation management activities, resource allocation, and work sequencing. This will allow for better coordination across contractors, internal teams, and engagement with property owners.
- Modernised geospatial vegetation systems: Mapping and spatial analysis tools will be upgraded to improve positional accuracy, integrate vegetation growth modelling, and link directly with operational and asset management platforms. This will support proactive clearance planning and reduce the likelihood of vegetation-related outages.
- Continuous improvement and capability building: We will embed structured processes for reviewing vegetation management performance, sharing lessons learned, and building targeted capability across our teams and contractors. This will ensure that practices adapt effectively to changes in vegetation growth patterns, weather impacts, and regulatory expectations.
- OPEX optimisation and risk-aligned planning: Our budgeting and operational design will adapt to emerging regulatory requirements and climate-influenced growth patterns. We will forecast potential cost pressures while keeping vegetation-related outages and customer impacts to a minimum.

## Refurbishment or disposal

Our approach to refurbishment and disposal is guided by asset condition, risk exposure, lifecycle cost, and compliance requirements. These activities are essential to maintaining network performance, managing risk, and ensuring the efficient use of resources.

### Current practices

Refurbishment and disposal decisions are made based on structured assessments of asset health, criticality, and performance history. Across our fleet, the following general practices apply:

- Refurbishment: Refurbishment is applied where life extension is technically viable and cost-effective. Activities typically include component replacement, servicing, reconditioning, or targeted upgrades to restore or enhance asset performance. Refurbishment is prioritised for high-value or critical assets such as transformers, switchgear, and mobile equipment, where replacement costs are significant and operational impact is high. These decisions are informed by CBARM modelling, fleet strategies, and asset condition data to ensure alignment with lifecycle objectives and network risk profiles.
- Disposal: Disposal is triggered when assets reach end-of-life, present safety concerns, become obsolete, or no longer comply with regulatory or performance standards. It involves the safe removal, decommissioning, and environmentally responsible handling of retired assets. Materials such as transformer oil, $SF_6$ gas, metals, and electronic components are managed in accordance with environmental and safety regulations. Where feasible, disposal options consider reuse, recycling, or resource recovery to minimise environmental impact and support our sustainability objectives.

These activities are coordinated through the Works Programme and governed by our lifecycle strategies, technical standards, and delegated authority framework.

### Planned improvements

To enhance our refurbishment and disposal capability, we plan to:

- Develop more detailed refurbishment criteria based on asset performance and cost-benefit analysis.
- Expand the use of CBARM (Condition Based Asset Risk Management) and Markov modelling to forecast refurbishment needs and optimise timing.
- Introduce a critical spares and rotables strategy to support refurbishment planning and reduce downtime.
- Strengthen disposal tracking and reporting, including environmental impact assessments and alignment with circular economy principles.
- Improve integration between asset condition systems and procurement planning to support timely decision-making.

These improvements will support Alpine's strategic goals of lifting asset management maturity, improving operational efficiency, and embedding sustainability into lifecycle decision-making.

## Fleet management

## Overhead structures

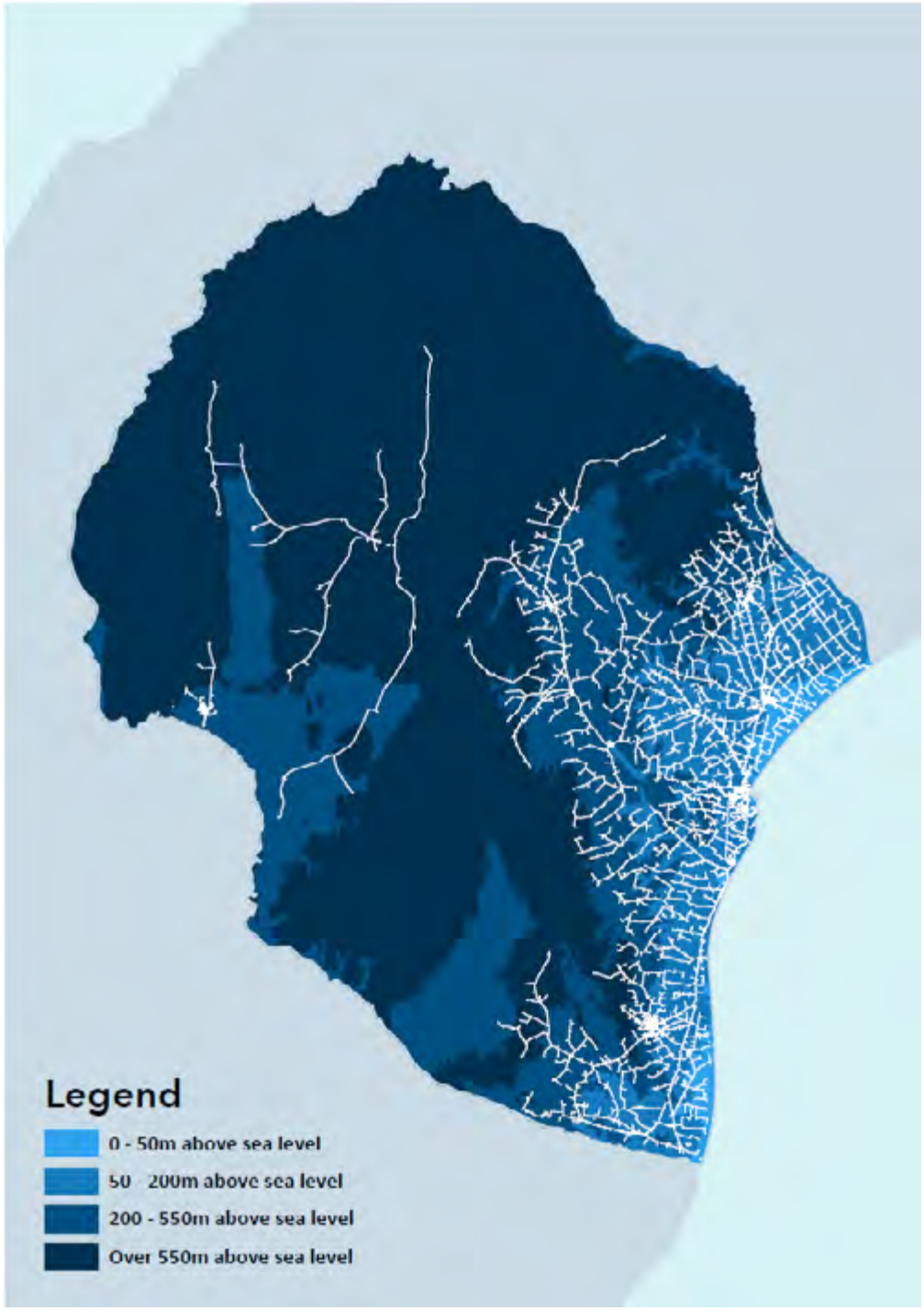
### Overview and role

Our overhead lines deliver electricity across urban, rural, and remote areas of the network. This portfolio includes poles, crossarms, conductors, and associated hardware, each serving a defined role in supporting safe and reliable power delivery. Our assets are designed and maintained to perform in varied environmental conditions, including coastal corrosion zones, snow loading areas, and seismically active regions. We manage them with a focus on resilience to extreme wind, heavy snow, ice accretion, the Alpine Fault AF8 earthquake, climate impacts, and tsunami risk, while meeting service quality, operational efficiency, and sustainability objectives.

## Role played by overhead structures

Our overhead structures form the backbone of electricity distribution across South Canterbury, connecting communities from rural farms to industrial centres. This portfolio includes poles, crossarms, conductors, and associated hardware, each engineered to support the safe and continuous delivery of power. These assets operate in varied environments ranging from coastal corrosion zones to snow-prone inland areas, requiring design standards that withstand strong winds, seismic activity, and climate impacts. Our management approach focuses on resilience, reliability, and sustainability by maintaining robust inspection, maintenance, and renewal programmes that ensure performance under extreme conditions. Through targeted investment and adaptive asset management, we continue to strengthen the integrity of our overhead network while supporting service quality and long-term community needs.

*Figure 58 | Overhead network.*



The high-level objectives for our overhead structures portfolio are outlined below, guiding how we design, maintain, and renew these assets to balance safety, performance, cost efficiency, and community impact.

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Apply Safety in Design principles to all structures.<br>Replace assets based on condition information before failure, ensuring responsible disposal of obsolete poles and components.<br>Source hardwood crossarms from sustainable forests. |
| **Service levels** | Continuously refine condition-based renewal techniques to improve feeder reliability (SAIDI and SAIFI), resilience, and end-of-life forecasts. |
| **Cost** | Deliver cost-effective designs, construction, operation, and disposal methods for all structures and lines. |
| **Community** | Reduce planned outages by aligning replacement work with other projects and minimise disruption to landowners during renewal activities. |
| **Asset management capability** | Maintain adequate and appropriately skilled resources to design, build, operate, maintain, and support a safe and reliable overhead network. |

Most of our 33 kV sub-transmission network was installed during the 1960s and 1980s to meet increasing rural demand, with a notable growth spike in 1996 driven by the construction of the 30 MVA dairy factory at Clandeboye. The 11 kV and 22 kV distribution networks were predominantly developed in the 1950s and 1970s, with minimal expansion during the 1980s and early 1990s as existing capacity met demand. All new low-voltage (LV) reticulation in urban areas is installed underground in line with district planning requirements, while rural LV overhead lines are maintained alongside the 11 kV systems.

The population and age statistics of our pole fleet reflect the network's development history and the varied service lives of different materials. Table 26 below summarises the number, type, proportion, estimated service life, and average age of poles across the network.

*Table 26 | Population and age statistics of pole fleet*

| Type | Number | % of total | Estimated life (Years) | Average age |
|---|---|---|---|---|
| **Hardwood** | 12,869 | 30% | 40-60 | 34 |
| **Softwood** | 4,771 | 11% | 25-50 | 29 |
| **Concrete mass reinforced** | 21,931 | 51% | 60-100 | 44 |
| **Concrete pre-stressed** | 3,821 | 9% | 60-100 | 6 |
| **TOTAL** | 43,392 | 100% | | |

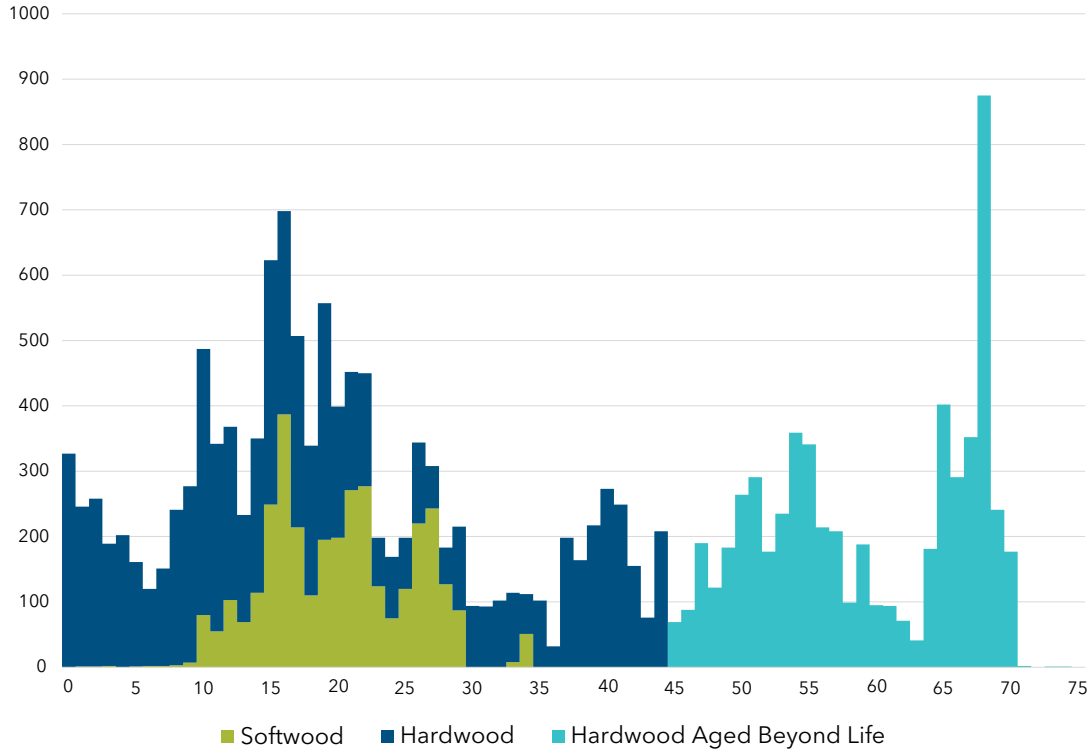
## Condition profiles

Our asset condition assessments combine inspection data, defect records, and performance history to understand deterioration trends and guide investment priorities. This integrated approach ensures we replace or renew assets at the right time, maintain safety, and sustain performance.

The pole population comprises timber, composite, and concrete designs, with materials selected to suit the environmental conditions of each location. Figure 59 shows the age profile for

timber poles, separating softwood, hardwood, and hardwood aged beyond its nominal service life. A significant proportion of hardwood poles remain in service well beyond their expected life, highlighting the need for targeted inspection and renewal programmes. Softwood poles are generally younger, reflecting more recent installation activity. However, their long-term performance varies considerably depending on the source and quality of the timber.

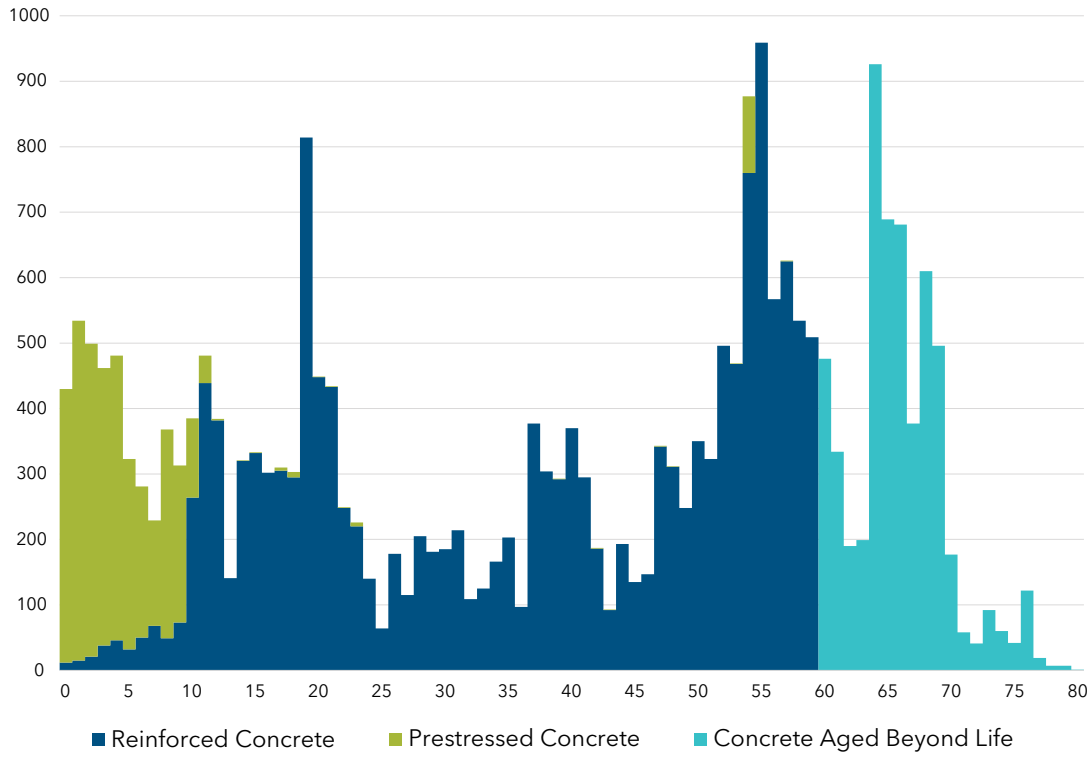
*Figure 59 | Wood pole age profile in years.*




In January 2014, a review of softwood poles sourced from fast-growing, immature forests concluded that this material would no longer be used on the network. The review found that these poles had lower durability than originally expected, leading to a reduction in their estimated service life from 40–50 years down to 25–50 years. The revised life expectancy now depends on ongoing condition assessment. By contrast, a small proportion of earlier generation softwood poles, installed between 1985 and 1986, have performed significantly better. These were sourced from mature forests, providing denser timber and greater resistance to decay.

Figure 60 presents the age profile for concrete poles, including reinforced and prestressed designs, as well as those aged beyond their nominal service life. A substantial proportion of reinforced concrete poles are approaching or exceeding their expected lifespan, requiring increased monitoring to manage potential end-of-life risks. Condition grading for all pole types is informed by biennial visual inspections, detailed construction checks for high-risk or ageing structures, and targeted structural testing where required.

*Figure 60 | Concrete pole age profile in years.*

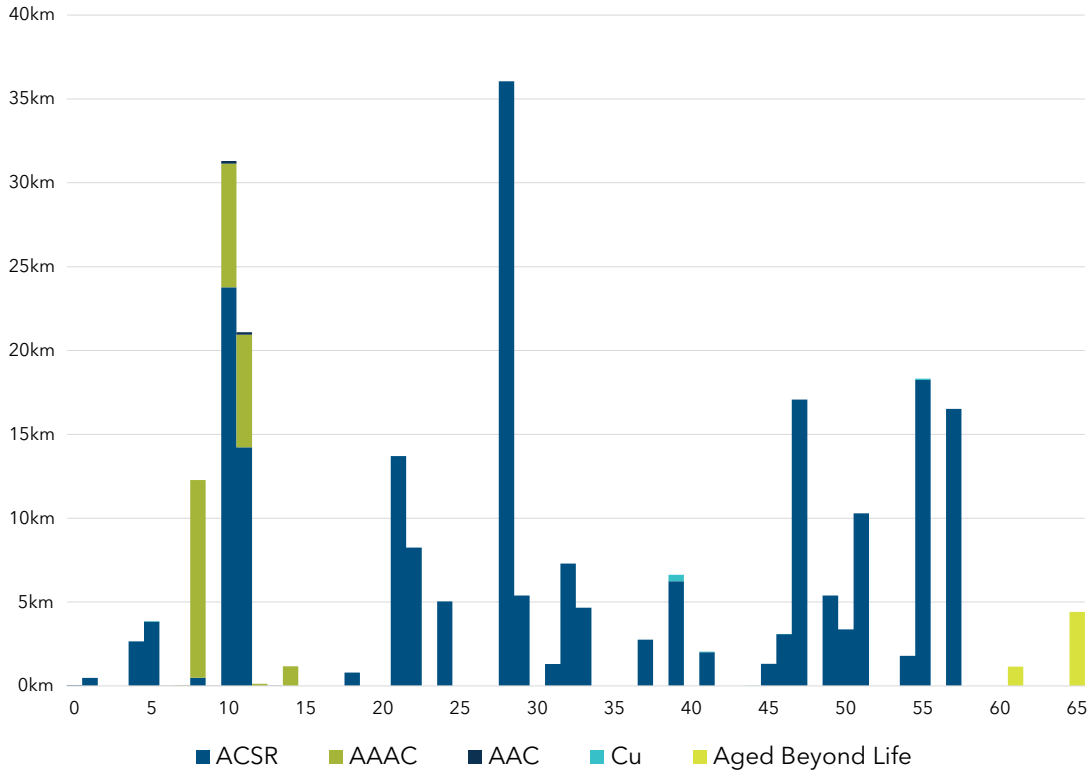



Our crossarm fleet comprises a range of materials and designs selected for specific network and environmental conditions. Condition is assessed through scheduled inspections that identify decay, mechanical damage, corrosion, and other defects that may compromise structural integrity or performance. Defect management systems track issues for all types, enabling targeted interventions prioritised by condition, risk, and exposure. This ensures timely replacements or repairs, avoids unnecessary renewals, and reduces the likelihood of failures. Where possible, crossarm work is coordinated with other planned network activities to improve efficiency and minimise service interruptions. Construction standards specify durable crossarm materials, protective coatings, and proven designs, with selection based on wind loading, conductor type, and environmental exposure. Consistent application of these standards, supported by ongoing monitoring, underpins long service life and ensures reliable performance.

Our conductor fleet is monitored through routine patrols, targeted inspections, and thermal imaging surveys to detect defects before they affect safety or performance. Assessments focus on corrosion, joint deterioration, strand breakage, and clearance loss caused by pole movement or conductor sag. Older conductor types, particularly galvanised steel, are more susceptible to accelerated degradation in coastal and high-wind areas and are therefore subject to closer monitoring. Inspection results are recorded in our asset management systems, supporting trend analysis and enabling targeted renewal planning.

Figure 60 shows the age profile of our sub-transmission conductor fleet by material type. Aluminium Conductor Steel Reinforced (ACSR) is the predominant type in service, while Aluminium Alloy (AAAC) and All Aluminium Conductor (AAC) make up smaller proportions. Copper conductors represent only a very minor share of the fleet.

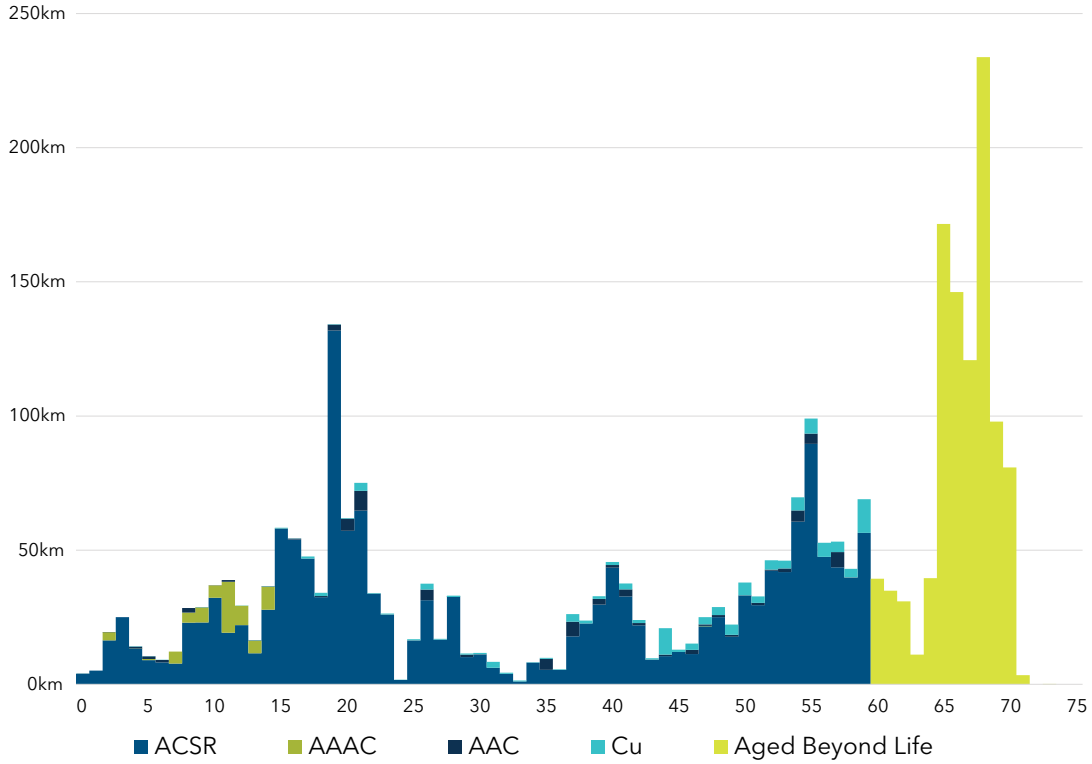
*Figure 61 | Sub-transmission conductor age profile in years.*




A notable portion of sub-transmission conductors have exceeded their nominal service life, which reinforces the need for ongoing condition monitoring. Most of the copper conductors, at around 51 years old, are confined to short sections within zone substation bus structures. As these sections are not subject to significant tension, they are not considered to be at elevated risk. Where conductors show defects or their clearances fall below required standards, we replace them with modern aluminium alloy designs that provide higher thermal capacity, reduced sag, and improved resilience to environmental stress, thereby enhancing network reliability and extending service life.

Figure 61 shows the age profile and quantity of our overhead distribution open wire conductors by type. Aluminium Conductor Steel Reinforced (ACSR) remains the predominant material, with Herring, Gopher, Magpie, and Mink the most common configurations. Herring accounts for the largest share at 31 percent of our ACSR fleet, and of this, 77 percent is 50 years or older. A notable portion of other ACSR types are also approaching or beyond their nominal service life, particularly in older rural networks.

*Figure 62 | Distribution conductor age profile in years.*




Much of our ageing distribution conductor remains in serviceable condition thanks to ongoing inspections, maintenance, and targeted renewals. Replacement priorities are based on safety, reliability risk, and compliance with clearance standards, informed by patrols, detailed inspections, and defect reports.

Most of our low voltage overhead conductor network is located in urban areas and is predominantly constructed from copper. Figure 63 shows the age profile of our LV conductors, which also includes smaller quantities of AAC and ACSR. While a notable portion of copper conductor has exceeded its nominal service life, much of it remains in sound condition due to regular inspections, targeted maintenance, and renewal programmes. Replacement priorities are driven by safety, reliability risk, and compliance with clearance requirements, ensuring that end-of-life assets are systematically upgraded to maintain network performance.

*Figure 63 | LV conductor age profile in years.*

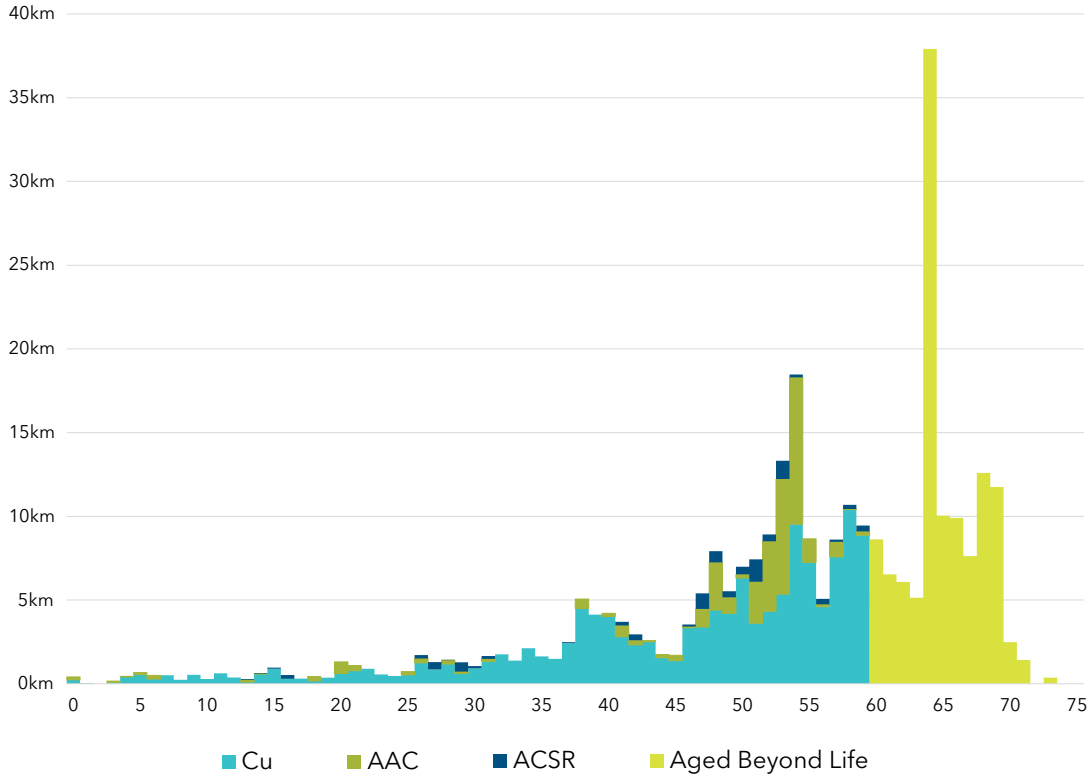
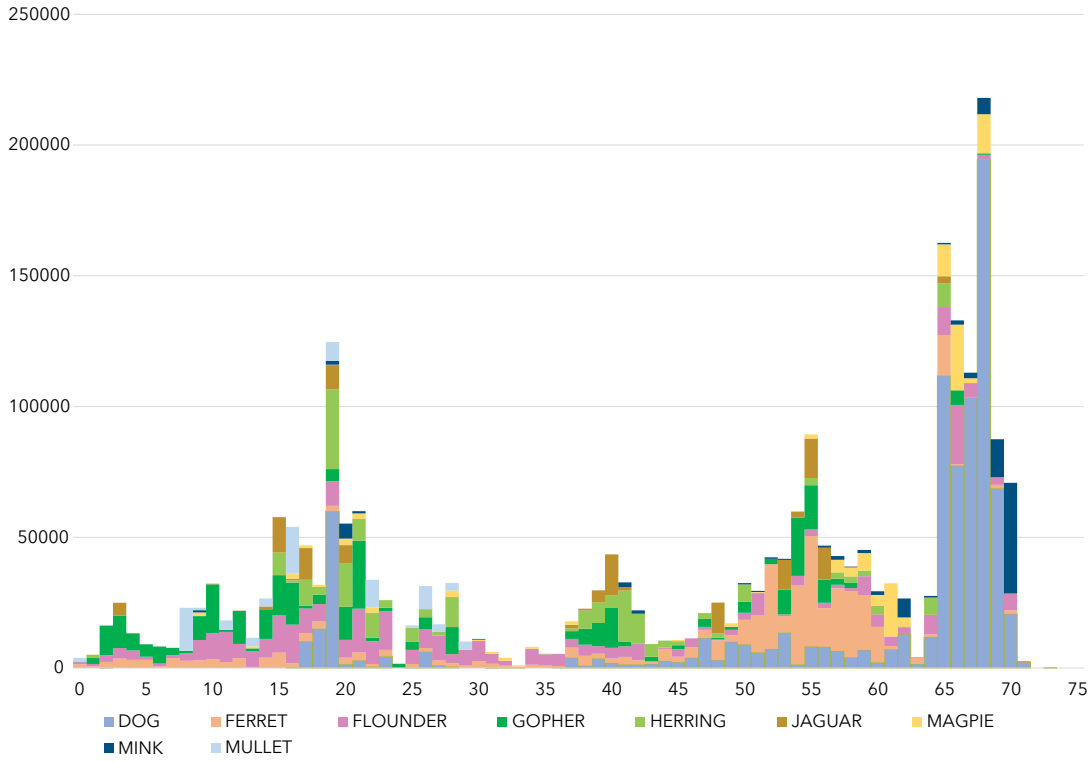



Figure 64 shows that our ACSR conductor fleet is composed of a variety of types, with Herring, Gopher, Magpie, and Mullet making up the largest shares. The age profile indicates several distinct installation periods, with significant volumes dating back 50 years or more. In particular, a notable concentration of Mullet and Mink types is clustered around the 65 to 70-year age range, well beyond typical nominal service life. While these assets remain in serviceable condition in many cases, their age profile reinforces the importance of targeted inspection and renewal programmes to manage condition-related risks and maintain network reliability.

*Figure 64 | ACSR conductor age profile in years.*



## Climate change and overhead network resilience

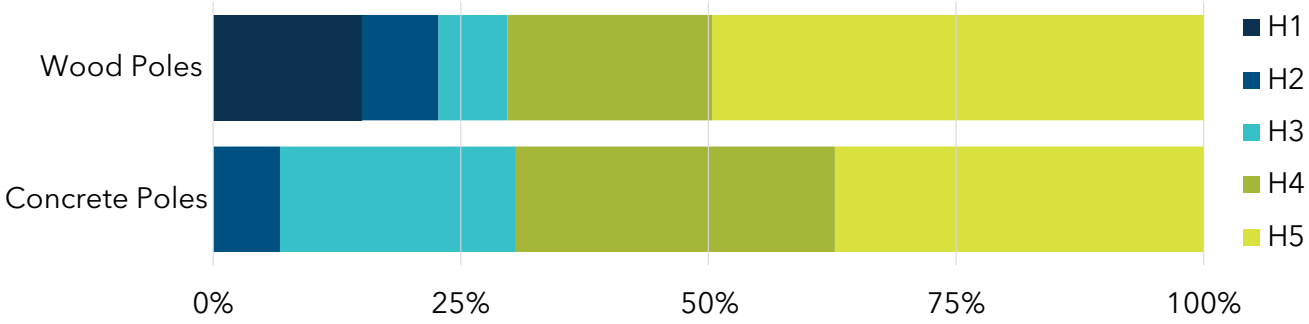
Climate change presents one of the most significant long-term risks to our overhead line network, with increased exposure to severe weather events such as thunderstorms, high winds, and snow loading. These conditions elevate the likelihood of asset damage, outages, and safety hazards across both rural and urban areas. To reduce this exposure, we are investing $8 million each year in strengthening our overhead network through targeted pole and conductor renewals, enhanced design standards, and forward-focused resilience planning. This investment ensures the continued reliability of electricity supply under changing climatic conditions, protecting communities and securing a network built for the future.

### Health profiles

The health profiles of our overhead line assets provide an informed view of their condition, expected remaining service life, and likelihood of failure. Using the Asset Health Index (AHI) methodology, we identify assets expected to remain serviceable for many years, as well as those that may requiring targeted intervention. While age offers a broad indication of asset health, it is only one of several factors considered. Environmental exposure, operational performance, and observed condition play a much greater role in determining true asset resilience. The following sections present the age-based health distributions for key overhead line asset classes, including poles and conductors, guiding renewal priorities and the investment needed to maintain network safety, reliability, and performance.

Figure 65 presents the Asset Health Index profile for our wood and concrete pole fleets, derived from an age-based assessment. Most poles in both categories are in good or very good health (H4, H5), indicating long remaining service life and a low likelihood of failure. About one quarter of the wood pole fleet falls into the fair to poor health range (H1 to H3), with around 15% in very poor health (H1). The age of these poles points to the need for continuous monitoring and near-term replacement. Concrete poles generally have a stronger profile, though a notable share is in fair health (H3) and expected to require renewal in the coming decades. The age-based perspective provided by the AHIs emphasises the need for continued pole inspections and timely investment to sustain performance and prepare for future replacement.

*Figure 65 | Pole structure asset health as of 2022/23.*




The age-based Asset Health Index profile for overhead conductors, shown in Figure 15, reveals a wide variation in condition across conductor types. AAAC conductors are in uniformly very good health (H5), indicating long remaining service life and minimal near-term replacement needs. AAC conductors present a more mixed picture, with a balanced split between fair health (H3) and good to very good health (H4, H5), suggesting that targeted renewal will be required over the coming decades. The ACSR fleet shows a higher proportion in the poor to fair health range (H1 to H3), with a small share in very poor health (H1), signalling the need for prioritised intervention to manage reliability risk. Copper conductors exhibit the weakest overall profile, with the majority in poor to fair health (H2, H3) and only a small portion in good condition, pointing to a significant renewal requirement in the medium term to maintain network performance and safety.

*Figure 66 | Overhead conductor asset health as of 2022/23.*

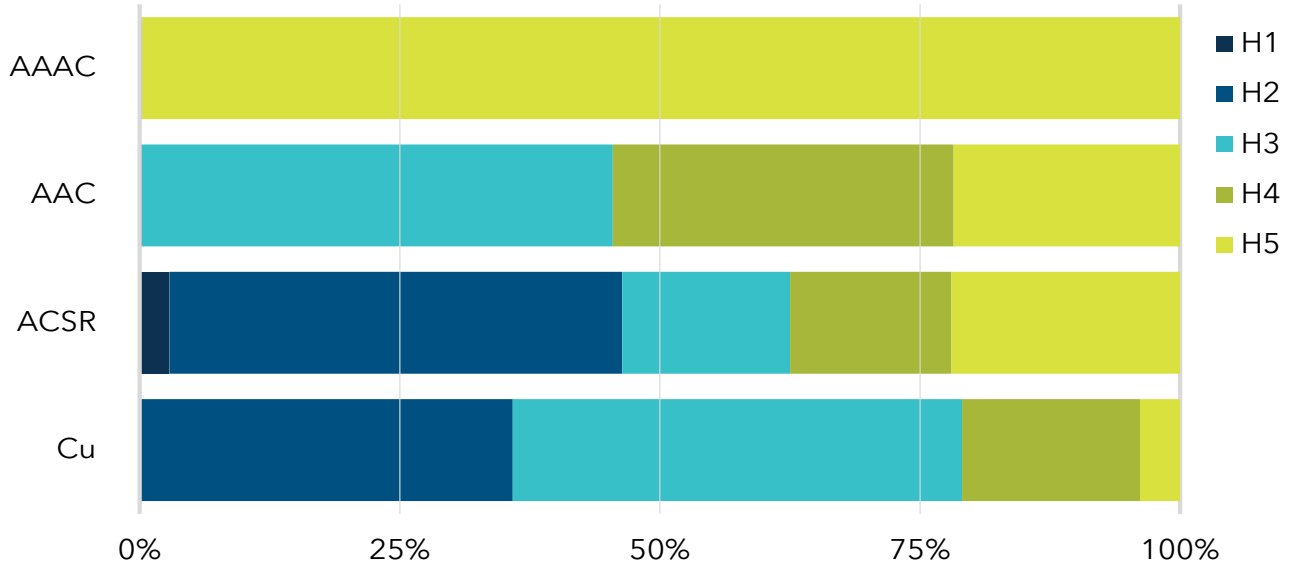



Table 27 summarises the total length and proportional share of each overhead conductor type across the network. ACSR dominates the fleet, accounting for more than four fifths of the total length, while copper conductors represent just under 12 per cent. The copper component is largely concentrated in short spans within some zone substations, often forming part of the bus structures. Given their typical age of around 51 years, these assets appear in poorer health on an age-based assessment. However, because they operate under minimal mechanical tension, they are not considered at significant risk of failure, and their condition profile does not present the same renewal urgency as similar-aged conductors under higher operational stress.

*Table 27 | Overhead conductor type length and percentage of total.*

| Type | Length (km) | % of total |
|---|---|---|
| **AAAC** | 62 | 2.1% |
| **AAC** | 63 | 2.2% |
| **ACSR** | 2590 | 89.0% |
| **Cu** | 177 | 6.1% |
| **Other** | 18 | 0.6% |
| **TOTAL** | 2909 | 100% |

## Maintenance and renewal strategy

The challenges associated with the condition and performance of poles are as follows.

- **Softwood pole resilience improvement:** Brown rot or structural degradation cause premature failure in softwood poles. To address this, softwood poles are no longer installed and a targeted softwood pole replacement programme is in progress strengthening network resilience.
- **Mass-reinforced concrete pole performance:** These poles have proven generally durable, with premature deterioration being rare. Failures are most often linked to external events such as vehicle strikes, uneven snow loading, or tree interference. A small minority have failed through chloride or carbonation penetration, issues that are likely the result of poor-quality concrete or substandard workmanship during manufacturing.

- **Pre-stressed concrete pole management:** As a relatively young fleet, pre-stressed concrete poles have demonstrated strong performance to date. Their lighter weight, superior strength, and extended life expectancy offer clear advantages, although the longer length variants can suffer damage during installation due to deflection under their own weight.
- **Hardwood pole below-ground inspection**: Naturally durable and treated hardwood poles are dependable but require underground inspection from year 25 onwards. This process identifies almost all significant defects, though on rare occasions failures have occurred beneath the 500 mm inspection depth, highlighting the importance of thorough and consistent monitoring.
- **Hardwood cross-arm lifecycle management:** With a typical service life of 30 to 40 years, hardwood cross-arms generally need replacement before the supporting pole reaches its end-of-life. Crossarm renewal is carried out when condition assessments confirm the crossarm can no longer support operational loads.
- **Conductor wire performance and assessment:** Choosing conductor size and material requires balancing electrical, mechanical, environmental, and economic factors. Modern ACSR and AAAC conductors provide greater strength and have reduced pole and structure damage compared with older, weaker types. Remaining life is assessed through visual inspection of surface deterioration, dimension checks, and mechanical testing such as tensile strength, breaking load, and wire wrap testing for steel and aluminium. Metallographic analysis is also applied, together with alignment to British Standards BS 251, Australian Standards AS 3607, and Transpower Standard TP.SS 02.17 Transmission Line Condition Assessment. In determining conductor remaining life, we apply criteria of either a 20% loss in ultimate tensile stress across the whole conductor or a 15% reduction in aluminium cross-sectional area. These criteria vary between conductor types and will be reviewed with expert input as part of our ongoing reassessment programme.

## Community vigilance guarantees overhead line safety

Alpine depends on the community to walk alongside us in keeping the overhead line network safe and reliable. Alpine uses community vigilance to notice leaning poles, damaged crossarms, sagging wires, or overgrown vegetation near lines. Community vigilance allows our field teams to respond quickly, reducing the likelihood of failures, outages, and safety risks. At Alpine Energy, we view public reports as an integral part of our maintenance and renewal strategy. By working together with the community, we strengthen network resilience, safeguard the quality of electricity supply, and uphold a shared commitment to safety.

### Renew or dispose

Concrete poles generally last 60 to 100 years, hardwood poles 40 to 60 years, and softwood poles 25 to 50 years. Softwood poles are no longer allowed on the network, and a structured replacement programme is underway. Few concrete poles will reach the end of their life in the next 30 years, while hardwood poles are replaced only when they reach the end of service.

Although an age-based approach suggests around 750 poles should be replaced each year, we use condition as the more reliable guide. We are currently replacing about 740 poles a year and aim to maintain a steady rate of 750.

Disposal of treated wood poles remains difficult until an environmentally sustainable option is found. At present, they are sold to the public, donated to community projects, or given to non-profit organisations. Damaged concrete poles are gifted to landowners or crushed and recycled, while untreated hardwood is reused as firewood or recycled.

Pole renewal is closely managed alongside conductor replacement. The dairy and irrigation industries have accelerated the renewal of older, less resilient conductors, particularly at network extremities. Climate change is likely to increase storm-related damage, especially in areas

exposed to flooding, strong winds, and snow. For now, conductor replacement is expected to remain steady over the next decade, rising gradually beyond the current planning horizon. Old conductor is usually sold for scrap, although some types in good condition are kept for emergency repairs. 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 2027 period are detailed in Table 28.

*Table 28 | Overhead line replacement and renewals program.*

| Project | Timing (FY) | Cost ($'000) |
|---|---|---|
| OHL Temuka East ARR Milford TMK 02 Milford Huts : Replacement of ageing distribution assets at Murray Street and Milford or Clandeboye to improve resilience, reduce maintenance, and support future demand. | 2027 | 855 |
| Reconductor Wilken Street Future Demand and Resilience : Reconductoring and LV upgrades in Temuka to improve resilience, reduce outages, and support an LV ring with a new ground mounted transformer and RMU. | 2027 | 603 |
| Upgrade GLD 191 Township Feeder Capacity Breach : Upgrade of the G191 to G168 overhead section to address forecast capacity exceedance and maintain reliable performance. | 2028 to 2029 | 1200 |

## Underground cables

### Overview and role

Our underground cable network complements the overhead system by delivering safe and reliable electricity supply in urban, industrial, and high-density areas where overhead construction is less practical or less acceptable. The portfolio covers sub-transmission, distribution, and low-voltage (LV) cables, along with associated joints, terminations, and cabinets. These assets support network resilience by reducing exposure to weather-related faults, although they present higher complexity and cost when failures occur.

Our underground cable portfolio is grouped into three fleets, each with specific characteristics and management needs:

- **Sub-transmission cables:** These operate mainly at 33 kV, with the 11 kV Timaru supply cables also treated as sub-transmission because of their critical role and meshed configuration. Assets include cables, joints, and terminations. Two insulation types are in service, namely paper-insulated lead-covered cables, which have provided dependable service for many years, and cross-linked polyethylene, which is now the standard for new installations and repairs due to its improved construction and safety features.
- **Distribution cables:** This fleet operates at 11 kV and consists of cables, joints, and terminations. Both paper-insulated lead-covered and cross-linked polyethylene remain in use. Cross-linked polyethylene, introduced locally after the mid-1970s, is the preferred option for renewals and new works. Paper-insulated lead-covered is still serviceable in parts of the network and is managed through condition-based interventions.
- **Low-voltage cables:** Operating at 230 or 400 volts, the low-voltage network includes cables, link boxes, cabinets, in-ground boxes, and pillar boxes. The number of connections on each section depends on customer density, with supply from the distribution transformer to the final consumer usually limited to about 400 metres. Service connections are typically made inside pillar boxes located at property boundaries. Maintaining the integrity of these boxes is a key public safety priority, managed through inspection, maintenance, and progressive renewal.

The high-level objectives for managing the underground cable fleet are outlined in Table 29. These objectives focus on safety, customer service, cost efficiency, community impact, and developing asset management capability.

*Table 29 | Underground cable portfolio objectives.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Eliminate public safety incidents involving the underground cable network. All excavation on or near our network is controlled through the BeforeUDig process. |
| **Customer service levels** | Minimise customer interruptions during maintenance and renewal activities. Keep customers informed of planned outages. Expand the programme of mobile generation connection points to support supply during planned works. |
| **Cost** | Ensure all investment is justified through structured risk assessment and risk-reduction reviews. Plan and resource maintenance activities to minimise plant outages and optimise efficiency. |
| **Community** | Apply appropriate traffic management to minimise disruption during road-based cable repairs. Maintain property access when trenching occurs in road corridors. |
| **Asset management capability** | Maintain complete and accurate asset records in the Enterprise Asset Management (EAM) system. Develop and implement fleet maintenance strategies within EAM. Continue staff training on cable assets through industry programmes such as the EEA. |

Standardisation supports the efficient management of the underground cable fleet. By using consistent designs and equipment, we can manage both capital and maintenance expenditure in a more cost-effective way. The standard cable sizes in service on our network are listed in Table 30.

*Table 30 | Standard cable sizes.*

| 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. |

All standard cables are aluminium with XLPE insulation. Multicore or single-core designs are applied depending on the installation requirements. Other conductor sizes may also be used where higher current ratings or specific design needs must be met.

## Condition profile

Our network contains about 849 kilometres of underground cable, operating across low-voltage (230/400 V), distribution (11 kV and 22 kV), and sub-transmission (33 kV) systems. The majority of this length is in the distribution and sub-transmission fleets, which together account for more than half of the total. Table 31 summarises the quantity and proportion of underground cable by voltage.

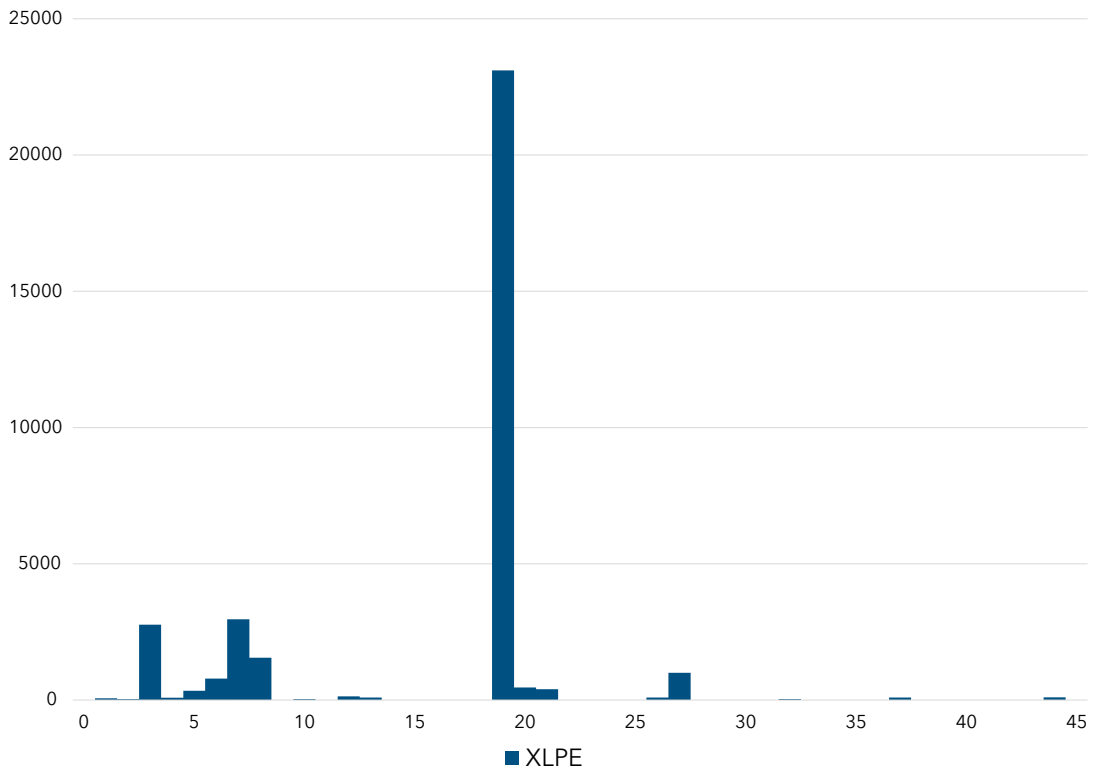
*Table 31 | Underground cable circuit lengths.*

| Voltage | Length (km) | % of total |
|---|---|---|
| 400 V | 380 | 43% |
| 11kV | 462 | 52% |
| 22kV | 17 | 2% |
| 33kV | 34 | 4% |
| **TOTAL** | **893** | **100%** |

Cable life expectancy varies with cable type and installation period. Paper-insulated lead-covered (PILC) cables, which have been in service internationally for over a century, are typically expected to have a life of around 70 years. Cross-linked polyethylene (XLPE) cables installed before 1986 are expected to last about 40 years, while those installed after advances in materials and construction introduced in 1986 are expected to last closer to 60 years. These assumptions are deliberately conservative and installed in conditions which are likely to extend their service lives.

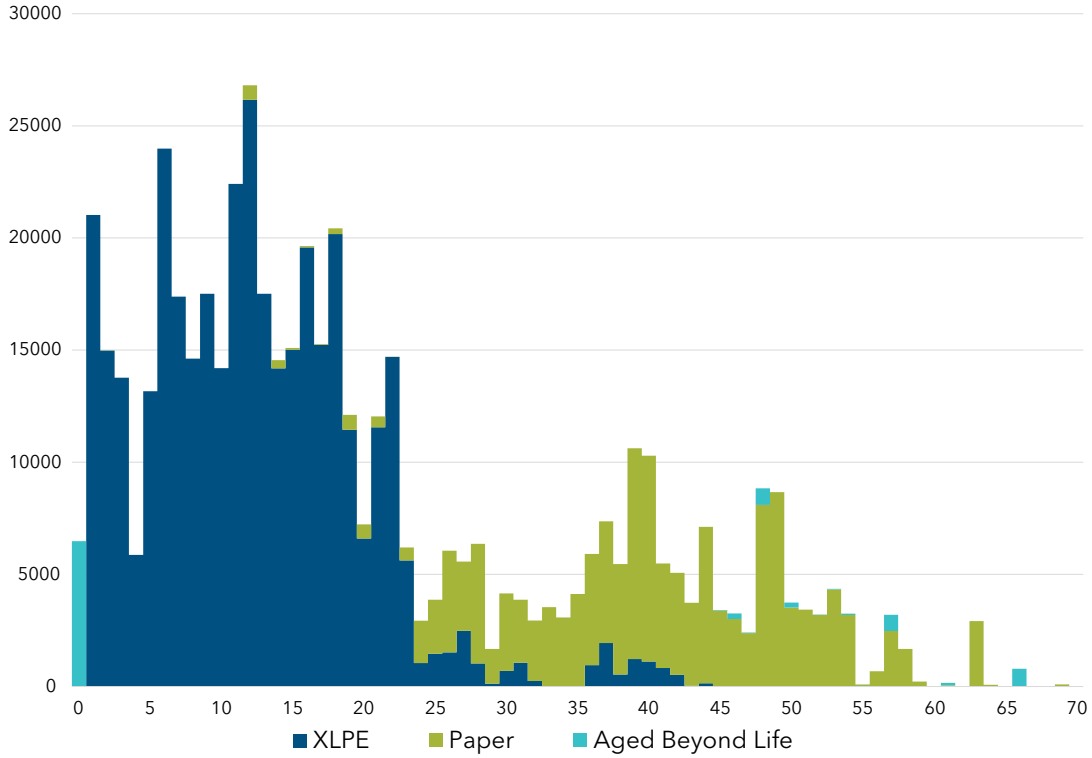
Almost all 33 kV sub-transmission cables are less than 40 years old and are of XLPE construction. Figure 67 shows the age profile of the sub-transmission fleet. A significant portion of the youngest group, around 17 years old, are the two cable circuits between the Temuka GXP and the Clandeboye substation that supply Fonterra. In addition, 24 kilometres of 33 kV-rated cable currently operates at 11 kV. This higher-rated cable was installed with the intention of a future voltage upgrade when required by demand growth.

*Figure 67 | Sub-transmission cable age profile in years.*



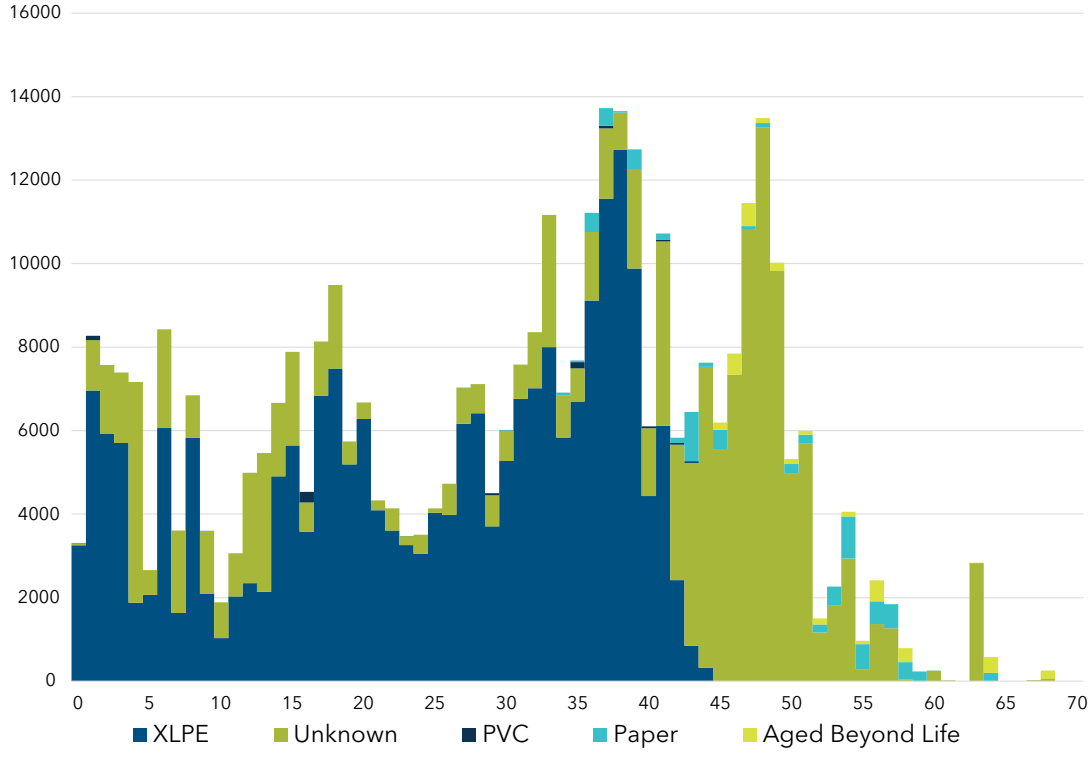

The 11 kV distribution cable fleet comprises both paper-insulated lead-covered (PILC) and cross-linked polyethylene (XLPE) designs. Figure 68 shows that around 85 percent of the network has been installed in the last 40 years, with half of the fleet less than 16 years old. The newer installations are almost entirely XLPE, while the older sections are predominantly PILC.

*Figure 68 | Distribution cable age profile in years.*




The LV cable fleet includes XLPE, PVC, and paper-insulated lead-covered (PILC) designs, with a portion of cables recorded with unknown insulation types. Figure 69shows that most of the LV network has been installed within the last 40 years, with a clear concentration of newer XLPE cables. Older sections of the fleet are largely PILC, while a small share of PVC remains in service. The unknown category, mostly less than 25 years old, is expected to be predominantly XLPE. Our high-voltage XLPE cables are assumed to last 45 years and paper-insulated cables around 70 years.

*Figure 69 | LV cable age profile.*



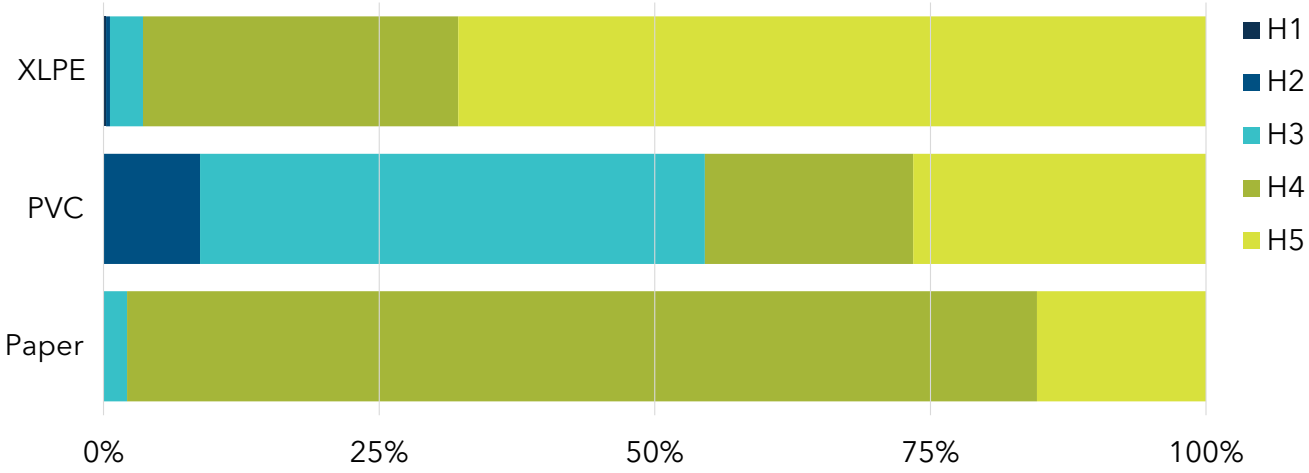
## Working together for cable safety and resilience

Our underground cables are vital to delivering a reliable electricity supply across South Canterbury. Each year, we invest 1.2 million dollars to renew and strengthen this infrastructure, ensuring it continues to serve our communities safely and efficiently. Alongside our monitoring and renewal programmes, we rely on the public to help protect these assets. Before carrying out any digging, trenching, or landscaping work, community and industry are asked to contact BeforeUDig to locate buried cables and conduits. This step reduces damage, outages, and injury. By working together with our community, we safeguard the network, maintain reliability, and support a safer region.

### Health profile

Our underground cable fleet is generally in good condition, with performance supported by routine monitoring and targeted testing. Trends from condition assessments and data from premature failures are used to refine expectations of remaining life and to inform renewal priorities. Figure 70shows the age-based asset health profile for our distribution cables, while all sub-transmission cables are less than 40 years old and are therefore considered low risk in the near term.

*Figure 70 | Underground cable asset health as of 2022/23.*




Low-voltage PVC cables present the most significant risk. They are susceptible to water ingress through the insulation and joints, leading to corrosion of aluminium conductors and eventual failure. By contrast, XLPE insulation is resistant to water penetration, although joints remain a potential weak point if not properly sealed. Paper-insulated lead-covered cables continue to perform adequately, but their condition requires ongoing monitoring as they age.

In the Timaru CBD, LV cable circuits include legacy main reticulation cables buried in the street, feeding conduit systems attached to the fronts of buildings. These above-ground conduit systems are retained unless building demolition requires replacement, as full underground conversion is costly and not always economically justified. Given the seismic status of many CBD buildings, a staged renewal approach will be taken as strengthening or replacement works proceed.

### Maintenance and renewal strategy

Cables are largely maintenance-free as they are buried for most of their length. Maintenance therefore focuses on above-ground components such as terminations, distribution boxes, and link boxes. HV cable terminations are inspected and tested every 30 months to confirm condition. Testing is matched to asset importance and risk. For critical 33 kV and 11 kV sub-transmission cables, very low frequency (VLF) partial discharge testing is the preferred method, as it avoids insulation stress from HVDC techniques. Megger insulation tests are applied during

commissioning, while HVDC equipment is used at reduced voltage settings for fault location to avoid overstressing unaffected sections.

While cables are generally reliable, their condition, performance, and long-term resilience are shaped by recurring issues. Faults most commonly occur through third-party interference such as excavation, but they can also arise from degraded components or installation deficiencies. Insights from our network show that these factors strongly influence how the fleet is operated, maintained, and renewed. Our cable management approach is thus set out as:

- **Condition-based management:** Targeted interventions are guided by defect identification tools, including partial discharge detection, thermal imaging, and hotspot monitoring. These methods help confirm asset condition and allow issues to be addressed before they develop into failures.
- **Joint reliability and failure risk:** Cable faults most often arise from joint failures, poor installation practices, or external mechanical interference. To manage these risks, 11 kV sub-transmission cables in Timaru are now subject to biennial VLF partial discharge testing, an increase from the previous five-year cycle, to track deterioration and guide timely intervention.
- **Routine testing and inspection regime:** Critical 33 kV and 11 kV sub-transmission cables are also tested every two years using VLF techniques. HV and LV terminations are inspected on a five- to ten-year cycle, while above-ground terminations are checked every 30 months to identify UV-related degradation. Patrols are also carried out to detect risks such as oil leaks, vermin exposure, or mechanical damage.
- **Low-voltage PVC cable risks:** PVC-insulated LV cables are vulnerable to water ingress through the insulation and joints, which can lead to corrosion of aluminium conductors and eventual failure. While XLPE insulation is resistant to water penetration, joints remain a potential weak point if not properly sealed. Management of this fleet focuses on monitoring, targeted intervention, and progressive renewal.
- **Renewal planning and prioritisation:** Cable replacements are planned on the basis of condition, age, and capacity risk, rather than age alone. This approach ensures investment is prioritised where the risk to safety, supply, or performance is greatest, aligning renewal activity with long-term resilience objectives.

Our approach to renewing underground cables is based on both condition and age. Cable insulation inevitably deteriorates over time, with operating temperatures and sunlight exposure being the main factors impacting ageing insulation, screens, and outer coverings. Cables identified through inspections, condition assessments, or repeated failures as being in poor condition are prioritised for replacement. Replacement planning also considers the capacity requirements of the network. In the Timaru CBD, for instance, several of the oldest cables are undersized by today's standards and are nearing their capacity limits. One or more of these will need to be replaced or reinforced before 2030 to maintain supply.

## Zone substations

### Overview and role

Zone substations link the transmission grid with local sub-transmission and distribution systems. They step electricity between voltage levels, typically from 110 or 33 kV down to 11 kV, and provide the switching, protection, and load control needed for safe and reliable supply. These functions make them central to meeting demand, supporting resilience during faults, and maintaining service under changing environmental and operational conditions. The Zone substation portfolio covers six main fleets, along with associated assets that support zone substation operation:

- **Power transformers:** Convert electricity between voltage levels, enabling safe transfer from transmission to distribution networks. Power transformers are essential for ensuring supply capacity.

- **Indoor switchgear:** Housing circuit breakers and isolators inside controlled environments improves reliability and facilitates the electrical protection of our network.
- **Outdoor switchgear:** Provides high voltage switching and fault isolation in exposed environments. It supports operational flexibility and resilience by enabling sections of the network to be isolated safely.
- **Protection relays:** Detect abnormal conditions such as overloads or faults and trigger circuit breakers to prevent further equipment damage and maintain safety on our network.
- **Bulk metering:** Measures electricity at zone substations for accurate billing, regulatory compliance, and operational oversight. Revenue meters support customer billing, while check meters integrated with SCADA provide verification and monitoring for system analysis and planning.
- **Load control plant:** Manages demand on the network by controlling specific loads, helping to maintain system stability and defer capacity upgrades.
- **Buildings:** Provide housing for control rooms, indoor equipment, and auxiliary systems. They safeguard critical assets from environmental exposure and allow safe access for staff.

The Zone substation portfolio objectives are shown in Table 32.

*Table 32 | Zone substation portfolio objectives.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Embed safety in all designs.<br>Prevent lost-time incidents from arc flash faults.<br>Maintain SF6 registers and log gas quantities during maintenance. |
| **Customer service levels** | Refine condition-based maintenance to maximise reliability (SAIDI and SAIFI).<br>Provide mobile substation connection points at appropriate sites. |
| **Cost** | Deliver cost-effective design, construction, operation, and disposal. |
| **Community** | Maintain fit-for-purpose infrastructure aligned with risk mitigation and supply security standards. |

## Investing in resilient zone substations

Zone substations are central to a safe and reliable electricity supply, so we will invest $76 million over the next ten years to maintain, renew, and upgrade this fleet. Our priorities include safer modern switchgear with arc flash protection, targeted transformer renewal based on health data, and upgrades that improve flood and seismic resilience. We will also continue to use our mobile substation capability so that planned works and some fault responses can proceed with fewer outages and improved safety for our field crews. By strengthening assets, controls, and operational flexibility, we will lift reliability, reduce recovery times after events, and prepare our network for future demand.

### Power transformers

Power transformers are the core of every zone substation, linking transmission voltages to sub-transmission and distribution levels. They step power up or down as required, typically between 110, 33, and 11 kV, making them critical for balancing supply with demand across the network. Their role is central to ensuring service continuity, providing resilience during faults, and maintaining safety margins under changing environmental and operational conditions. Reliable

transformer operation underpins both network stability and customer outcomes, especially where single-transformer substations serve rural or industrial loads.

Power transformer objectives link directly to network resilience and customer expectations. Safety measures such as arc flash prevention and oil containment ensure transformers can operate securely in varied environments. Condition-based practices help avoid unplanned outages, keeping communities supplied during both routine and peak demand. Standardisation and predictive monitoring reduce long-term costs while extending service life, ensuring investment decisions are efficient and sustainable.

*Table 33 | Zone substation portfolio objectives.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Embed safety in all transformer designs and operations.<br>Eliminate lost-time incidents from arc flash or oil handling. Ensure compliance with oil management requirements. |
| **Customer service levels** | Maintain high reliability by refining condition-based maintenance.<br>Reduce forced outages through predictive monitoring and diagnostic testing.<br>Ensure mobile substation connection points are available where required. |
| **Cost** | Deliver cost-effective procurement, refurbishment, operation, and disposal of transformers. Standardise transformer sizes to improve interchangeability and reduce lifecycle costs. |
| **Community** | Minimise noise impact through low-noise specifications.<br>Maintain security of supply by providing fit-for-purpose transformers aligned with growth and demand risks. |
| **Asset management capability** | Strengthen asset health modelling, using dissolved gas analysis (DGA), diagnostic testing, and inspection data.<br>Improve fleet planning capability to support resilience and long-term performance. |
| **Safety & environment** | Embed safety in all transformer designs and operations.<br>Eliminate lost-time incidents from arc flash or oil handling. Ensure compliance with oil management requirements. |
| **Customer service levels** | Maintain high reliability by refining condition-based maintenance.<br>Reduce forced outages through predictive monitoring and diagnostic testing.<br>Ensure mobile substation connection points are available where required. |
| **Cost** | Deliver cost-effective procurement, refurbishment, operation, and disposal of transformers. Standardise transformer sizes to improve interchangeability and reduce lifecycle costs. |
| **Community** | Minimise noise impact through low-noise specifications.<br>Maintain security of supply by providing fit-for-purpose transformers aligned with growth and demand risks. |
| **Asset management capability** | Strengthen asset health modelling, using dissolved gas analysis (DGA), diagnostic testing, and inspection data.<br>Improve fleet planning capability to support resilience and long-term performance. |

The power transformer fleet at our zone substations has been developed steadily to meet growth in demand, particularly through rural electrification and industrial expansion. Most units are three-phase transformers rated between 1 and 40 MVA, with the majority at 33/11 kV or 11/33 kV. A smaller number of higher-rated transformers connect directly at 110 kV. Growth in dairy processing, irrigation, and industrial loads has been the main driver of new installations, particularly since the 1990s.

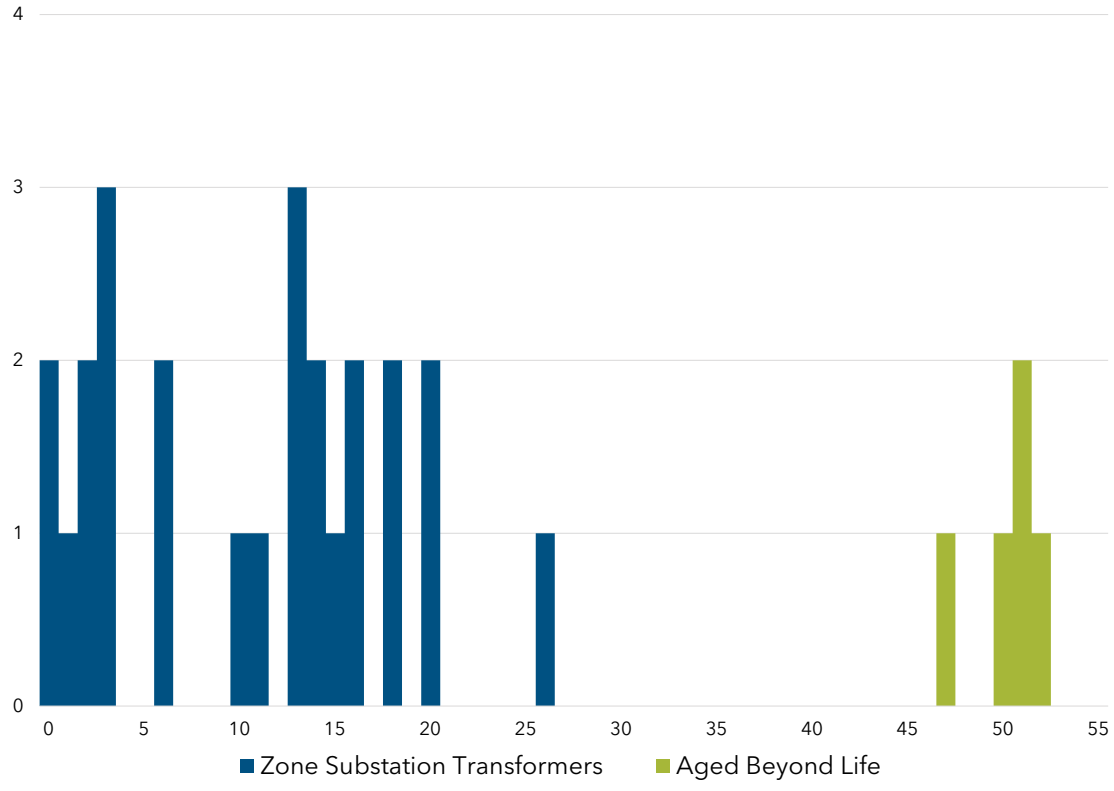
We currently operate 27 zone substation transformers across the network. Of these, 20 are 33/11 kV units (including three step-up 11/33 kV units), two are 110/33/11 kV, and two are 11/22 kV. The portfolio also includes one 33/11 kV transformer assigned as a dedicated spare, one mobile substation transformer rated 9 MVA, and two additional 33/11 kV spares to provide contingency support.

*Table 34 | Zone substation transformer population.*

| 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%** |

The distribution of transformer age is shown in Figure 71. Many of the larger units were installed between the 1960s and 1990s to support regional demand growth. More recent installations include higher-capacity units designed to meet modern load standards and provide greater operational flexibility.

*Figure 71 | Zone substation transformer age profile in years.*

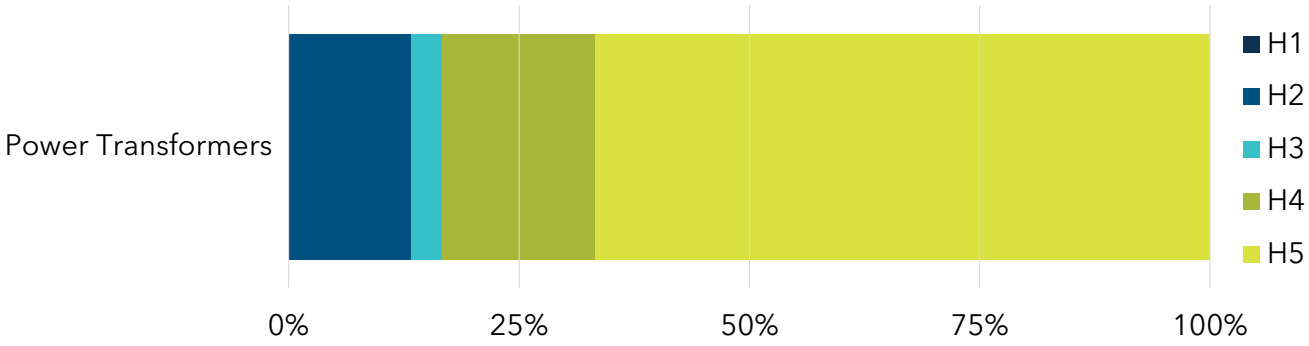


Overall, the power transformer fleet reflects a mix of older assets, some approaching their nominal service lives, and newer assets introduced through growth projects or replacements. This distribution highlights the importance of ongoing condition assessment and refurbishment programmes to extend the life of older units while ensuring capacity is available where demand is rising. The overall condition of the zone substation transformer fleet is good, with most units performing reliably and well within expected service lives. Older transformers are generally located at sites with lower average loads and many have undergone mid-life refurbishments, which helps them remain serviceable for 50 years or more.

Condition is assessed using a combination of inspection regimes, performance monitoring, and diagnostic testing. Routine inspections focus on oil levels, cooling systems, bushings, and auxiliary equipment. Dissolved gas analysis (DGA) is used to detect incipient faults, while thermal imaging, acoustic monitoring, and partial discharge detection provide early warning of defects. Performance records, such as fault events and tap-changer operation data, are also reviewed to build a fuller picture of condition.

We use the Asset Health Index (AHI) framework to evaluate the long-term serviceability of power transformers. The AHI combines age, condition assessments, diagnostic test results, and operational performance to provide a balanced measure of risk and remaining life. This approach ensures that investment planning is targeted at the assets most likely to affect reliability and safety.

*Figure 72 | Power transformer asset health.*




The current health profile shows most transformers in the good to very good categories (H4–H5), indicating strong condition and long expected life. Around one-fifth of the fleet is assessed as fair (H3), while a smaller portion is rated in poorer categories (H2). No units are in the worst health band (H1).

The AHI profile demonstrates that the fleet remains robust but highlights the need for continued monitoring of those transformers approaching mid to late life. Linking this profile with renewal planning ensures investment is prioritised where risk is greatest, protecting supply reliability, maintaining safety, and supporting long-term resilience of the sub-transmission and distribution systems.

## Reinforcing transformer resilience for the future

At Alpine Energy, we regard our power transformers as strategic assets that underpin network resilience and community confidence. We use advanced condition-monitoring techniques, including dissolved gas analysis, to identify and address faults before they occur. Transformer sizes and designs are being standardised to reduce lifecycle costs and improve interchangeability across the network. We are also adopting low-noise and low-emission designs to align with community expectations for environmental responsibility. Through smarter diagnostics, consistent design, and proactive renewal, we are strengthening supply reliability, supporting future growth, and maintaining a safe and sustainable network for South Canterbury.

Building on the AHI portfolio and condition monitoring findings, our maintenance and renewal strategy focuses on targeted monitoring, diagnostics, and intervention to sustain transformer health and manage risks as the fleet ages. The key factors influencing our maintenance and renewal strategy are.

- **Condition-based management:** We apply diagnostic tools such as dissolved gas analysis (DGA), oil quality testing, and thermal imaging to identify deterioration pathways early. These methods provide assurance of asset health and support targeted intervention before failures occur.
- **On-load tap changer reliability:** Tap changers are among the more failure-prone components. Mechanical wear, contact degradation, and insulation breakdown are monitored through operational counters, oil testing, and inspection. Maintenance programmes focus on reducing the risk of in-service malfunction.
- **Bushing condition and monitoring:** Bushings represent a known failure risk if deterioration is not detected early. We manage this through insulation resistance tests, power factor testing, and periodic replacements where condition indicates higher probability of failure.
- **Ageing fleet management:** While most transformers are in good health, a portion of the fleet is entering later life stages. These units undergo closer surveillance and, where necessary, refurbishment or redeployment to lower-risk sites to maximise their useful life.
- **Routine inspection regime:** Monthly visual inspections cover cooling systems, oil levels, seals, foundations, and ancillary equipment. Annual maintenance includes dehydrating breather servicing, Buchholz relay gas checks, and acoustic/thermal condition assessments.
- **Spare and mobile capacity:** To manage unplanned failures or major planned outages, we maintain spare transformers and a mobile substation. This capability reduces the risk of extended supply interruptions and improves resilience.

Power transformers have a standard service life of around 45 to 55 years, though actual life depends on condition, loading, and operational environment. Our strategy to link diagnostic monitoring with condition-based intervention ensures that maintenance is focused where the risk to supply, safety, or performance is greatest. Renewal is usually triggered by poor condition identified through inspections, asset health indices, or dissolved gas analysis, or where forecast load growth is expected to exceed the transformer's rating. Supply security requirements at some substations can also necessitate the addition of new or replacement units.

Replacement decisions are therefore based on a combination of condition and capacity drivers rather than age alone. In practice, most of our transformer replacements have been triggered by increased load demand, while condition-based replacements have been less frequent. Where feasible, transformers removed from service are refurbished and redeployed at other sites to maximise asset value.

Disposal practices follow environmental and safety standards. Oil is drained and treated or recycled, copper and steel components are recovered, and unusable material is disposed of through approved contractors. Where refurbishment is uneconomic, transformers are dismantled and recycled as far as possible to reduce environmental impact. Table 35 sets out the power transformer replacements planned for this period, reflecting the balance between condition, capacity, and security drivers.

*Table 35 | Power transformer replacement/renewal program.*

| Zone substation transformer | Timing (FY) | Estimate ($'000) |
|---|---|---|
| Replace Pleasant Point power transformer | 2030 | 2,200 |
| Replace Twizel Village power transformer | 2032 | 2,000 |
| Replace Fairlie Zone power transformer | 2031 | 1,500 |
| **TOTAL** | | **7,400** |

## Indoor switchgear

Indoor switchgear provides the switching, protection, and control functions that enable safe operation of zone substations and the wider distribution network. Installed inside purpose-built enclosures, this equipment houses circuit breakers, isolators, busbars, and associated control devices, protecting them from environmental exposure and improving reliability compared with outdoor switchgear. Table 36 presents our indoor switchgear population categorised by operating voltage rating and insulating medium used within the switchgear.

*Table 36 | Indoor switchgear population by operating voltage rating and insulating medium.*

| Voltage | Air | Solid Dielectric | SF6 | Oil | Total |
|---|---|---|---|---|---|
| **11kV** | 145 | 2 | 0 | 16 | 163 |
| **33kV** | 0 | 1 | 6 | 0 | 7 |
| **TOTAL** | **145** | **3** | **6** | **16** | **170** |

This switchgear forms a significant portion of our zone substation assets. The fleet includes both 11 kV and 33 kV installations, with most units operating at 11 kV. The majority of the fleet is 11 kV vacuum type switchgear, reflecting the transition to vacuum technology as the standard for new installations and replacements. Bulk oil units remain in two substations and are being phased out.

Indoor switchgear is central to managing faults, maintaining service continuity, and ensuring safe access for maintenance. Indoor switchgear also supports resilience by reducing the likelihood of weather-related failures and providing compact solutions for urban and industrial substations where space is limited. Our management focus with indoor switchgear is on embedding safety in all designs, sustaining reliability through condition-based maintenance, and ensuring efficient, cost-effective investment. Table 37 summarises our objectives with indoor switchgear.

*Table 37 | Indoor switchgear portfolio objectives.*

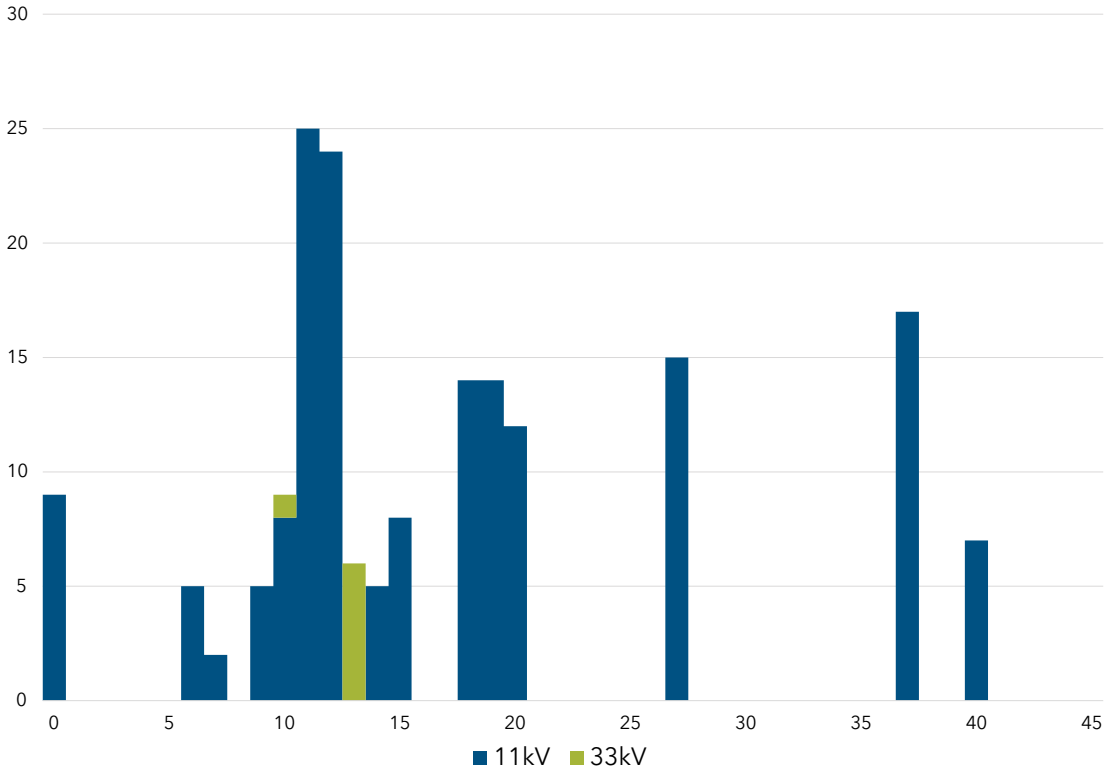
| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Incorporate arc flash detection, containment, and venting into all new installations.<br>Maintain compliance with SF6 management standards.<br>Ensure safety in design and operations. |
| **Customer service levels** | Refine condition-based maintenance to maximise reliability (SAIDI and SAIFI).<br>Provide secure and flexible switching arrangements to reduce outage durations. |

| | |
|---|---|
| **Cost** | Deliver efficient lifecycle management by standardising switchgear specifications and using condition data to prioritise renewal.<br>Ensure investment decisions remain cost-effective over the long term. |
| **Community** | Install switchgear in buildings that integrate visually with their surroundings in urban areas.<br>Apply appropriate safety and access measures to minimise disruption during maintenance and renewal works. |
| **Asset management capability** | Maintain accurate asset data in the EAM and GIS systems.<br>Develop and implement fleet maintenance strategies.<br>Ensure staff and contractors are trained in safe operation and emerging technologies. |

These objectives link directly to resilience and reliability by ensuring that investment decisions are risk-based and forward-looking. Enhancing safety and maintaining condition-based maintenance programmes protect customers from extended outages, while standardisation and accurate asset data improve cost efficiency and support long-term planning.

The age profile of indoor switchgear is shown in Figure 72. Most of the 33 kV fleet has been installed in the last 10 years, with the Pareora Zone Substation units commissioned in 2011. By contrast, the oldest equipment is found at Twizel Village (71 years old) and Tekapō Zone Substation (38 years old), where bulk oil switchboards remain in service. These older units are approaching the end of their practical lives and are scheduled for replacement during this planning period.

*Figure 73 | Indoor switchgear age profile in years*



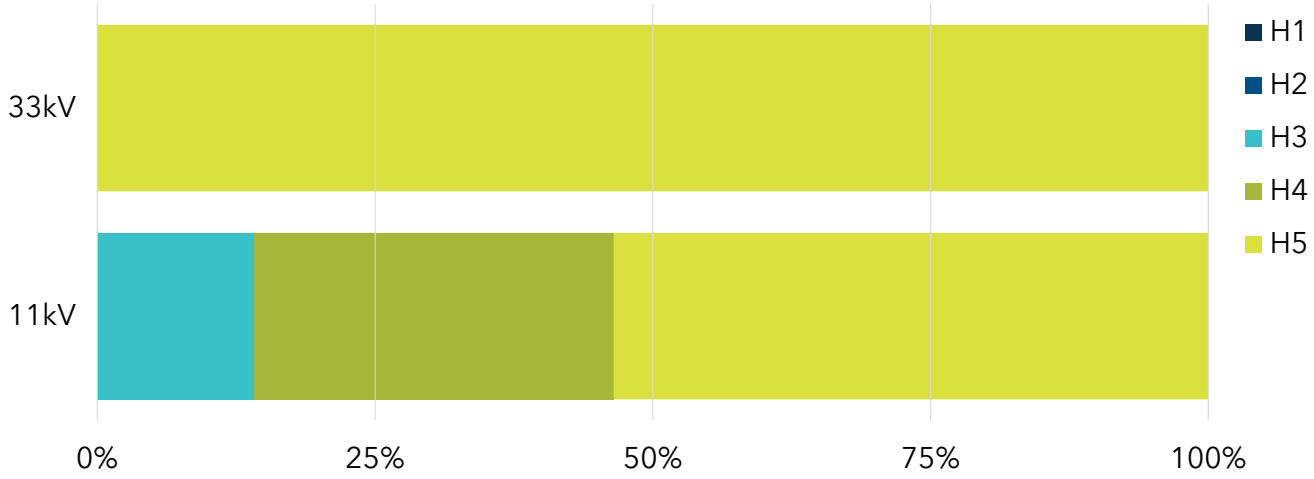

The age profile highlights the shift towards vacuum switchgear technology over the past three decades, to achieve improvements in reliability, safety, and maintainability. Our continued renewal of bulk oil units will complete this transition and align the fleet with current standards.

Indoor switchgear condition is assessed through a combination of inspection results, defect records, and operational performance. End-of-life is defined as the point at which a circuit

breaker or switchboard can no longer be relied upon to operate safely and effectively. Condition assessment therefore underpins renewal planning and ensures risks are identified before failures occur. Routine inspection and maintenance practices include monthly visual inspections, annual operational and diagnostic tests, and four-yearly insulation and resistance tests, supported by partial discharge testing where appropriate. These activities help identify degradation in insulation, contacts, mechanisms, or ancillary systems, and guide targeted interventions.

The age-based asset health profile is shown in Figure 74. All 33 kV indoor switchgear is in very good condition, with the six SF6-insulated panels installed at Pareora in 2011 expected to provide many years of reliable service. At 11 kV, most vacuum circuit breakers also sit in the good to very good range, consistent with their relatively recent installation and proven reliability. A smaller proportion of the fleet is in the mid-health category (H3), reflecting older units such as the bulk oil switchboards at Tekapō (38 years), which are approaching the end of their practical service life.

*Figure 74 | Age based indoor switchgear asset health index.*




Analysis of the AHI confirms that about 10 percent of the fleet will require replacement within the next decade, with bulk oil units being the main priority. These assets have higher maintenance requirements and pose and increased arc flash safety risk. By contrast, vacuum switchgear continues to show strong performance and low failure rates, supporting extended service lives where condition remains sound. The H3 proportion of the AHI analysis als indicates a need for planned renewal over the next 10 years, focusing on bulk oil equipment that is now obsolete and presents higher operational risk. No assets are currently in the H1 or H2 categories, confirming that the fleet is generally reliable and suitable for continued operation.

## Indoor switchgear and network protection

We use indoor switchgear to disconnect faulted circuits, protect our network from damage, and improve safety for staff and the public. Each year, our equipment undergoes detailed condition monitoring, partial discharge testing, and remote diagnostics to detect wear or deterioration early. This proactive approach allows us to identify assets nearing the end of their service life and address issues before failures occur. We also use standardised designs and spare-ready modules so that when a circuit breaker fails, it can be replaced quickly with minimal disruption to customers. Through these measures, we maintain a safe, reliable, and resilient network.

Linking the health profile with renewal planning ensures that resources are directed to the most critical areas, maintaining supply reliability, reducing safety risks, and supporting long-term network resilience. Indoor switchgear is generally reliable, but safe and effective operation depends on routine inspections, condition-based interventions, and managing specific risks such as arc flash and obsolescence. Our approach is set out below:

- **Condition-based management:** Performance is monitored through inspection, thermal imaging, partial discharge detection, and acoustic emission testing. This allows defects to be identified early and corrective action taken before failure occurs.
- **Routine inspections and servicing:** Circuit breakers, cabinets, and panels are visually inspected each month. Annual maintenance includes operational tests and diagnostic scans, while comprehensive servicing such as insulation testing, oil sampling, and mechanical checks is undertaken every four years or as required.
- **Arc flash risk management:** Arc flash remains a significant safety concern. All new switchboards include detection, containment, and venting systems, while older units are progressively retrofitted with blast-proof doors, arc flash detection, and venting. Operational practices include remote switching, PPE requirements, and restricted access during maintenance.
- **Bulk oil circuit breaker replacement:** Bulk oil units are increasingly difficult to maintain due to declining manufacturer support and spares availability. These assets are prioritised for renewal with vacuum technology, which offers higher reliability, reduced maintenance, and improved safety.
- **Standardisation and lifecycle planning:** New installations use standardised designs to reduce lifecycle costs and improve spare interchangeability. Renewal planning is informed by asset health results, capacity requirements, and network resilience needs.
- **Critical spares and contingency:** Spare switchgear units and critical components are held in the fleet to enable rapid replacement or fault recovery, ensuring network resilience and minimising downtime during unplanned events.

Indoor switchgear renewal is guided by condition, age, reliability, and safety requirements. The standard service life is assumed to be 40–50 years for vacuum and $SF_6$-insulated switchgear, while bulk oil units have a shorter practical life due to obsolescence and safety concerns. Renewal is triggered when:

- **Condition:** Systemic faults, insulation breakdown, or component failures occur.
- **Reliability or safety:** Assets present arc flash risks or fail to meet modern safety expectations.
- **Capacity:** Load growth exceeds equipment rating or requires more flexible switching.
- **Economical:** Maintenance costs rise above the cost of replacement.
- **Obsolescence:** Spare parts and technical support are no longer available.

Our disposal practices depend on the indoor switchgear equipment type. Bulk oil circuit breakers are decommissioned with oil removed and handled as a controlled substance. $SF_6$-insulated equipment is managed under gas handling standards to capture and log all quantities. Serviceable vacuum breakers may be refurbished for redeployment, while non-reusable components are recycled where possible.

Looking ahead, targeted replacement of the oldest 11 kV bulk oil switchboards at Tekapō substation is required, with future projects focusing on migration to standardised vacuum technology. New indoor switchgear projects also adopt designs that integrate arc flash protection and align with long-term resilience and safety objectives.

## Outdoor switchgear

Outdoor switchgear provides the switching, protection, and isolation functions needed to operate the network safely and reliably at zone substations. It includes circuit breakers, air-break switches, load-break switches, fuses, links, and reclosers. These assets are critical for fault clearance, enabling equipment to be safely de-energised, and for providing flexibility in operation and maintenance.

Unlike indoor switchgear, outdoor switchgear is directly exposed to weather, contamination, and environmental conditions, which influences both performance and maintenance needs. Its role is particularly important for resilience, as it allows rapid sectionalising of the network during faults and supports supply continuity during planned works.

Table 37 elucidates that our outdoor switchgear objectives focus on balancing safety, resilience, and long-term cost efficiency. By embedding condition-based practices and maintaining accurate asset data, we can target investment where risks are greatest while ensuring customer reliability and minimising community impact.

*Table 38 | Outdoor switchgear portfolio objectives.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Ensure safe operation by embedding arc-flash, oil containment, and SF6 management into all designs and maintenance.<br>Minimise environmental impacts through proper disposal and handling of oil and SF6. |
| **Customer service levels** | Maintain reliable supply by refining condition-based maintenance and enabling flexible switching to minimise outage durations during faults and planned works. |
| **Cost** | Optimise lifecycle costs by standardising switchgear specifications, prioritising replacement based on condition and risk, and coordinating works with associated assets to achieve efficiencies. |
| **Community** | Reduce local impacts by applying appropriate safety, access, and traffic management during maintenance or renewal works.<br>Ensure substations and switchgear integrate appropriately with surrounding environments. |
| **Asset management capability** | Maintain accurate and current data in EAM and GIS systems to support decision-making.<br>Develop maintenance and renewal strategies for different switchgear types, and ensure staff and contractors are trained in modern diagnostic tools and safe handling of oil and SF6 equipment. |

Table 39 shows the distribution of outdoor circuit breakers by voltage rating and type. Most are installed at 33 kV, reflecting their role in protecting power transformers and sub-transmission circuits. The 11 kV fleet is smaller, as most switching at this level is performed indoors, while 22 kV units are a historical legacy. Two 110 kV breakers have also been installed in recent years, reflecting growth in higher-voltage connections.

*Table 39 | Outdoor circuit breaker population by voltage rating 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** |

The arc interrupter medium technologies in service are summarised in Table 40. About 43% of circuit breakers are SF6-insulated, reflecting modern practice for outdoor installations. A further 38% are vacuum types, which are increasingly favoured due to their reliability and lower environmental footprint. Oil-filled breakers, while now only 20% of the fleet, remain in service at several 33 kV substations and are closely monitored because of their higher maintenance and safety risks.

*Table 40 | Outdoor circuit breaker population by voltage rating and interrupting media.*

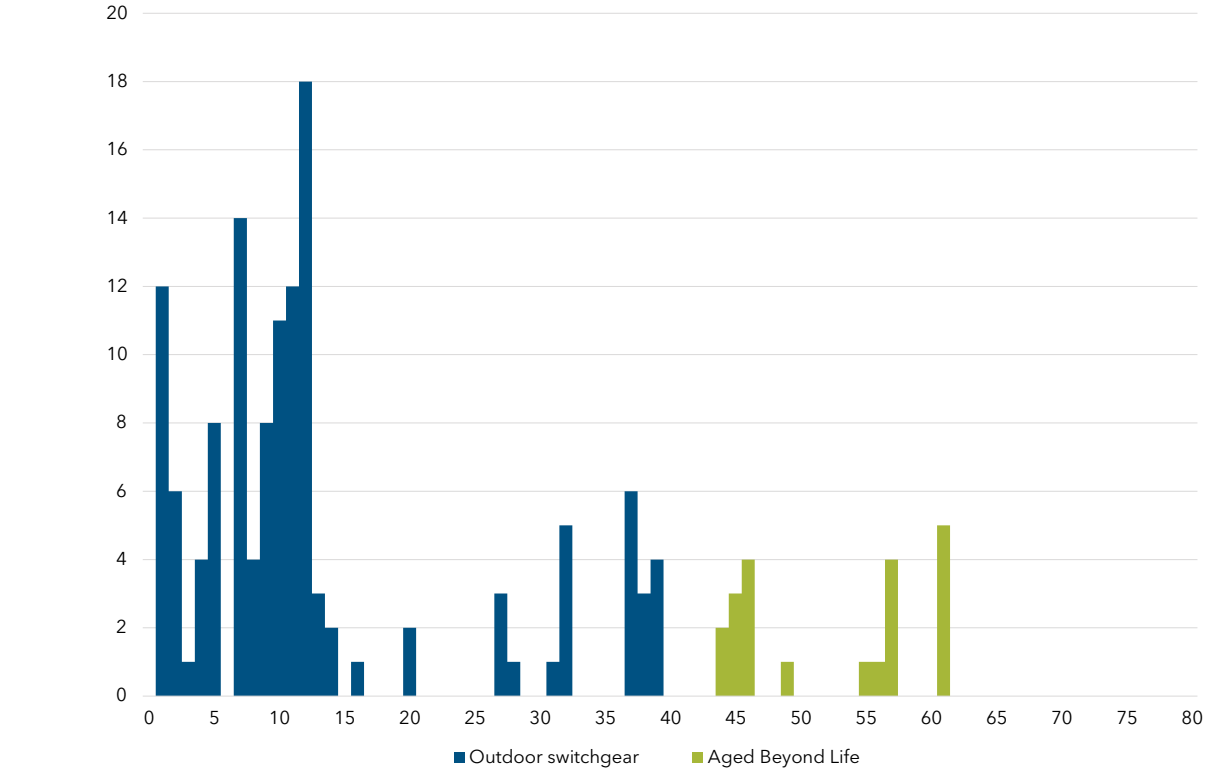
| Operating Voltage | Oil | Vacuum | SF6 | Total |
|---|---|---|---|---|
| 110kV | - | - | 2 | 2 |
| 33kV | 8 | 5 | 9 | 22 |
| 22kV | - | 2 | - | 2 |
| 11kV | - | 8 | 6 | 14 |
| **TOTAL** | **8** | **15** | **17** | **40** |

## Outdoor switchgear for fault management and reliable supply

Outdoor switchgear forms the first line of defence for our overhead network, isolating faulted circuits, protecting critical assets, and restoring supply quickly. Operating in exposed environments, this equipment faces constant weather and contamination risks, making early fault detection essential. Our outdoor switchgear follows standardised designs, supported by readily available spares, allowing repairs to be completed quickly and efficiently. This approach reduces customer disruption, enhances reliability, and strengthens the resilience of our network.

The combined age profile for outdoor switchgear is shown in Figure 75. While the majority of the fleet is under 40 years old, some units have exceeded 40 years of service. Outdoor switchgear generally has a service life of 40 to 55 years. Assets approaching this range are assessed closely, with replacement decisions informed by condition, criticality, and associated substation works.

*Figure 75 | Zone substation outdoor switchgear combined age profile in years*

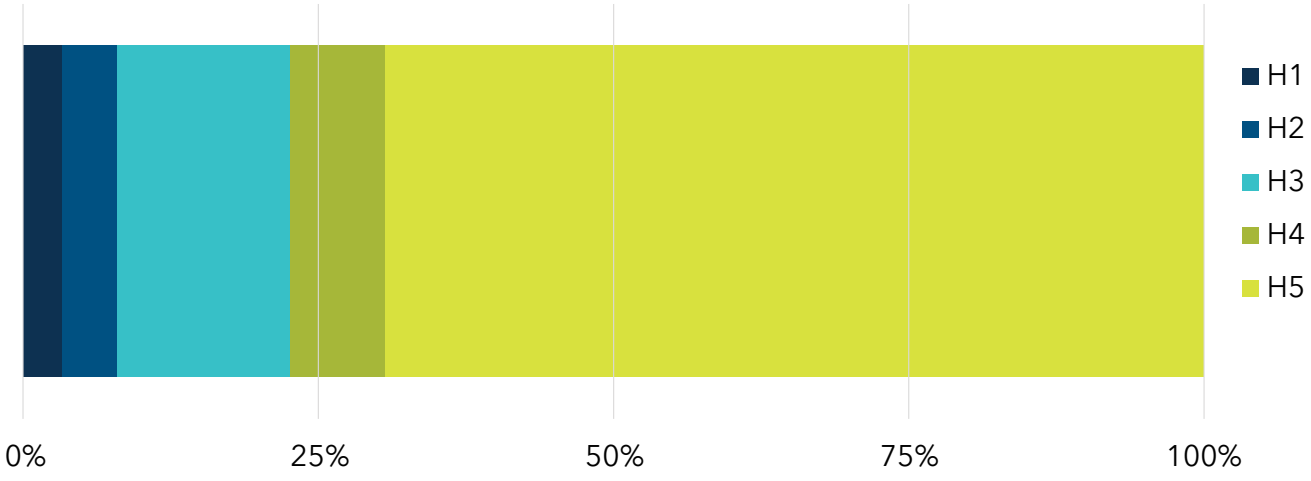



The condition of outdoor switchgear is influenced heavily by its exposure to the environment. Components are subject to moisture, dust, salt, and temperature extremes, which contribute to corrosion, insulation deterioration, and mechanical wear.

Oil circuit breakers (OCBs) carry higher operational and safety risks than vacuum or SF6 types. Frequent switching and fault interruption duties accelerate deterioration of contacts and insulating oil, increasing the likelihood of failure. Failures can be disruptive, and while rare, may result in explosions or fires. Vacuum circuit breakers (VCBs) and SF6 circuit breakers have demonstrated better reliability, lower maintenance needs, and stronger resilience in outdoor conditions. VCBs in particular are increasingly preferred due to their low environmental impact compared with SF6, while still providing robust interruption performance.

The age-based asset health profile for outdoor switchgear is shown in Figure 76. A small portion of the fleet sits in H1 and H2, reflecting assets nearing the end of serviceable life that require higher levels of attention. These include older circuit breakers, which are retained in service with regular inspection and refurbishment under our four-yearly zone substation maintenance programme.

*Figure 76 | Outdoor switchgear asset health*



Overall, most of the fleet is assessed in H4 and H5, indicating good to very good condition with no systemic concerns. Equipment in H3 and parts of H2 is dominated by oil-filled circuit breakers, which are less reliable than modern vacuum or SF6 units and require closer monitoring. These assets represent a medium term risk to reliability and safety and are being progressively replaced, with priority given to substations where the impact of failure would be greatest. The AHI profile shows that while most of the fleet is in good health, older oil-filled units require progressive renewal, making the design and construction of outdoor switchgear central to ensuring that replacements deliver reliability, safety, and long-term efficiency.

For outdoor 33 kV circuit breakers, our standard design is a live-tank SF6-insulated unit. SF6 technology has become the industry benchmark for high-voltage outdoor applications, combining compact construction with dependable interruption performance and adaptability to varied environmental conditions. Standardising on this design supports consistent resilience and efficient delivery, while also allowing flexibility in substation layouts where space or configuration is constrained.

Outdoor switchgear requires more routine and corrective maintenance than indoor equipment because it is directly exposed to the elements. Environmental exposure, ageing designs, and varying duty cycles create distinct performance and reliability risks. Our approach combines scheduled inspections, condition-based interventions, and technology-driven diagnostics to sustain safe and reliable operation.

- **Condition-based monitoring:** Diagnostic techniques such as thermal imaging, acoustic emission testing, and partial discharge (PD) detection are applied to identify defects before failure. Inspections align with the EEA Asset Health Indicator Guide and manufacturer recommendations.
- **Environmental exposure and ageing:** Outdoor assets face weathering, corrosion, and insulation deterioration. Maintenance focuses on visual inspections, cleaning, lubrication, and targeted refurbishment, with defective components replaced to extend service life.
- **Inspection and testing regime:** Monthly inspections include checks on circuit breakers, reclosers, and air-break switches. Biennial condition tests are performed on CBs, while full electrical and mechanical tests, including insulation and contact resistance checks, occur on a four-year cycle.
- **Oil circuit breaker management:** Oil-based circuit breakers carry higher risks of failure and potential fire or explosion. To mitigate these, these units are progressively replaced by SF6 or vacuum alternatives in line with renewal programmes.
- **Technology and innovation:** Modern tools such as drone inspections, GIS mapping, and SCADA-integrated relay data improve fault detection and inspection efficiency. These methods help target maintenance to the areas of highest risk while reducing time and cost.

Oil-filled circuit breakers typically reach the end of their practical life sooner than modern vacuum or SF6 designs, as their reliability declines with age and their maintenance burden increases. Vacuum and SF6 units provide longer and more consistent service, although their eventual replacement is still guided by both age and condition assessments.

Our replacement philosophy balances age-based expectations with condition data. Assets that continue to operate reliably after their nominal life can remain in service with refurbishment, while units that show systemic faults, rising failure risk, or safety concerns are prioritised for renewal ahead of schedule. In practice, this means older oil-filled breakers are being phased out first, while newer vacuum and SF6 units are expected to serve well into the future.

Over the next 10 years, replacement activity will focus on the small number of oil-filled circuit breakers still in service, particularly at substations where failure would have the greatest safety or reliability impact. Forecasts indicate a gradual but sustained replacement programme, with volumes driven more by condition and associated asset upgrades than by age alone.

At the same time, we continue to track industry developments in alternative technologies, such as vacuum and other low-emission solutions, to align future investments with both resilience needs and environmental objectives. This approach ensures that replacements not only maintain network reliability but also position the fleet to meet emerging regulatory and sustainability requirements.

Outdoor switchgear disposal practices follow environmental and community requirements. Oil from decommissioned breakers is safely removed and handled by approved contractors, with any contamination managed under environmental regulations. SF6 gas is recovered and processed to prevent release to the atmosphere. Metals and other materials are recycled where possible, while older mechanical components are disposed of in line with waste regulations.

Switchgear renewal also aligns with broader drivers of network resilience. The planned construction of a second 33kV supply point at Timaru GXP will, for example, remove the need to replace the 33kV outdoor switchgear at Timaru substation. Industry growth, new distributed generation, and increased electrification place higher loads on substations, sometimes requiring switchgear renewal in advance of expected life. In parallel, the increasing frequency of extreme weather events linked to climate change highlights the importance of modern, reliable switchgear to restore supply quickly after faults. Where switchgear is replaced, the opportunity is also taken to strengthen conductor connections and improve fault management capability, further supporting network resilience.

## Protection relays

Protection relays provide the first line of defence against electrical faults. Their role is to detect abnormal conditions such as short circuits, overloads, or equipment failures and to initiate rapid isolation of the faulted section. This minimises the impact of a fault on customers, protects expensive primary equipment such as transformers and switchgear, and upholds network safety standards.

Modern digital relays dominate our fleet, integrating advanced protection, control, and communication functions. These capabilities support resilience by enabling faster fault clearance, reducing nuisance trips, and providing operators with real-time system data through SCADA integration. Environmental controls within substations our protect relays from temperature and humidity extremes, helping maintain long-term reliability.

The objectives for protection relays, shown in Table 41, focus on safety, reliability, and cost efficiency while ensuring customer impacts from faults are minimised:

*Table 41 | Asset management objective and associated portfolio objectives.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Ensure reliable fault detection and clearance to protect people, equipment, and the wider network.<br>Embed safety in all designs and maintain compliance with electrical protection standards. |
| **Customer service levels** | Minimise the impact of faults and reduce outage durations by applying modern relay schemes.<br>Support improved SAIDI and SAIFI performance through fast and selective fault isolation, minimising consequential equipment damage during a fault. |
| **Cost** | Deliver cost-effective lifecycle management by standardising relay types, reducing duplication of functions, and prioritising renewals based on condition and risk |

| | |
|---|---|
| **Community** | Maintain security of supply by applying suitable protection schemes at critical substations.<br>Support community expectations for safe, reliable electricity supply. |
| **Asset management capability** | Maintain accurate configuration and operational data in EAM and SCADA systems.<br>Continue training staff in modern protection technologies and testing practices. |

Our protection relay fleet is a mix of electromechanical, static, and digital devices, with modern digital relays now forming the majority. Table 42 summarises the composition of the current protection relay fleet:

*Table 42 | Zone substation protection relay population.*

| Relay Type | Quantity | % of total |
|---|---|---|
| Electromechanical | 41 | 9% |
| Static | 27 | 6% |
| Digital | 387 | 85% |
| **TOTAL** | **455** | **100%** |

Digital relays dominate the fleet, reflecting a steady replacement programme over the last two decades. These devices provide improved functionality, integration with SCADA, and advanced self-monitoring compared with earlier types. Electromechanical and static relays remain in service at a few sites, but they are increasingly being replaced when substations are refurbished. Table 43 details the useful life of the various types of relays we have on our network.

*Table 43 | Protection relay useful life.*

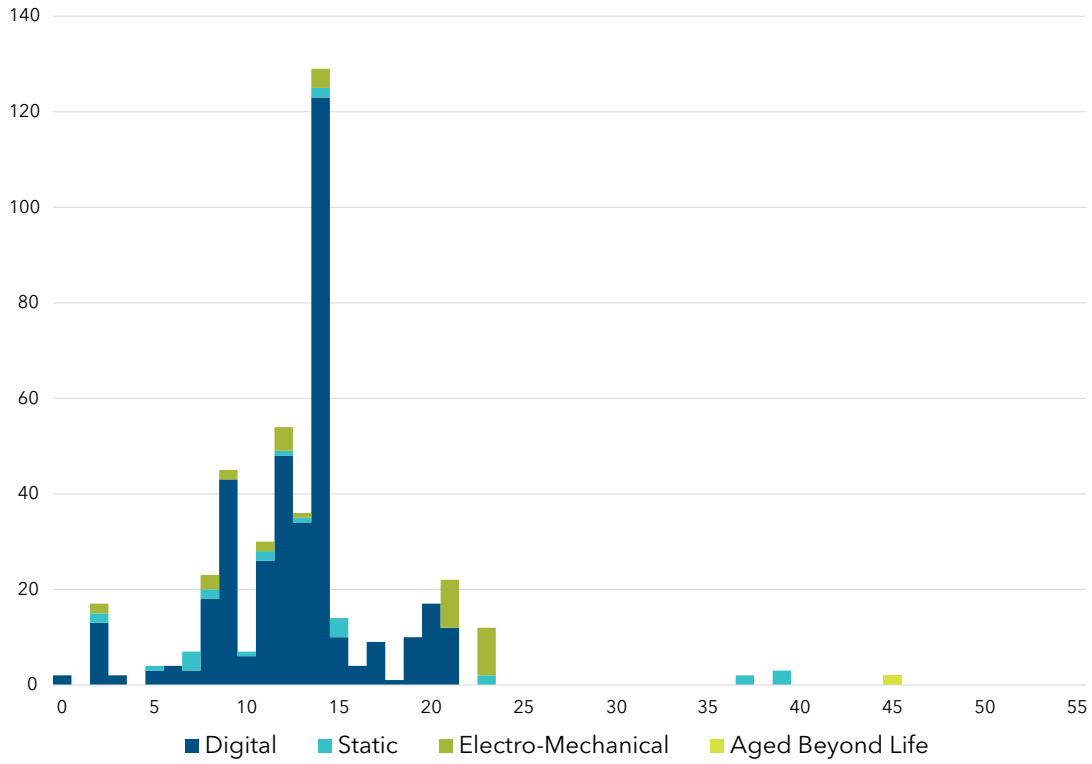
| Relay Type | Useful Life (Years) |
|---|---|
| **Digital** | 25 |
| **Static** | 25 |
| **Electromechanical** | 30-40 |

## The quiet guardians of our grid

Protection relays act as the unseen guardians of our electricity network, detecting faults in milliseconds and isolating affected sections to keep power flowing safely through the rest of the network. Modern digital relays combine precision with intelligence, using real-time monitoring and self-diagnostics to spot issues before they cause outages. Their integration with our operations room gives operators instant visibility across the network, helping faults clear faster and keeping customers connected. By standardising relay systems and using data-driven insights, we continue to strengthen protection, improve reliability, and ensure the grid remains resilient under all conditions.

The age profile of the fleet is shown in Figure 77. Nearly all relays (99%) are less than 25 years old, reflecting the modernisation of the fleet and the focus on resilience and safety through digitalisation. Only four electromechanical relays exceed 40 years of service, located at Timaru substation.

*Figure 77 | Zone substation protection relays age profile in years.*

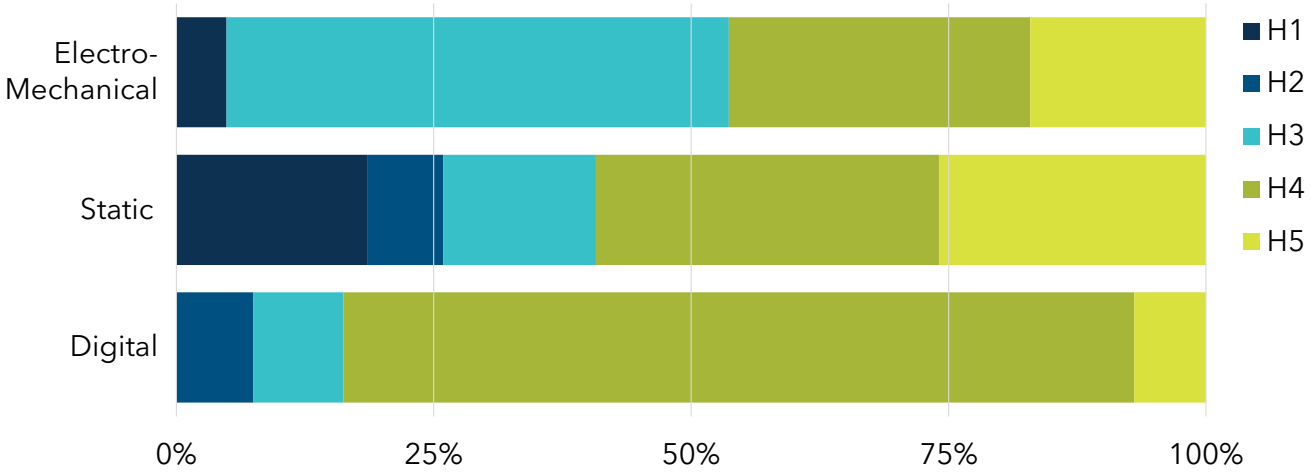



The condition of protection relays is assessed through a combination of periodic testing, self-monitoring functions (for digital relays), and performance records from fault events. Routine four-yearly testing verifies that trip circuits, current transformers, voltage transformers, and circuit breaker operations perform correctly. Digital relays extend this assurance by incorporating continuous self-diagnostics, which detect internal failures and report them via SCADA. Performance during faults also provides valuable evidence of relay reliability and accuracy in fault clearing events.

- **Electromechanical relays:** These older units rely solely on periodic testing for condition assessment. While many have exceeded their nominal life, several continue to perform reliably, though spare parts availability and calibration drift remain key risks.
- **Static relays:** Now largely obsolete, these relays are more difficult to maintain due to component ageing and declining manufacturer support. Failures typically relate to ageing electronics, and their condition is managed by prioritised replacement with digital units.
- **Digital relays:** These dominate the fleet and are supported by both periodic testing and continuous self-monitoring. Failures most commonly stem from capacitor degradation late in life, but their diagnostic functions and SCADA connectivity allow early detection and proactive replacement.

Overall, condition assessment confirms that modern digital relays are performing strongly, with risks concentrated in the older static and electromechanical populations. The AHI shown in Figure 78 provides an assessment of the relays based on their age and expected service life.

*Figure 78 | Protection relay asset health.*




The AHI profile demonstrates that the relay fleet is robust overall, with most assets in good to very good health. However, the presence of older static and electromechanical devices requires ongoing replacement to ensure network resilience and safety. Integrating AHI results into renewal planning ensures that investment is directed where risk is greatest, supporting supply reliability and protecting critical assets.

- **Electromechanical relays:** Concentrated in H3 to H4, with some units in H1 and H2 categories. These are ageing assets, with a small proportion already beyond their expected service life. While some continue to operate reliably, their declining supportability and increased failure risk mean they represent a near-term renewal priority.
- **Static relays:** Display the weakest protection relay age based health profile, with a notable proportion in H1 and H2. These are approaching or beyond end-of-life, reflecting obsolescence, reliability issues, and limited spare parts. Planned replacement with digital relays will continue over the planning period.
- **Digital relays:** Predominantly in H4 and H5, reflecting their relative youth and strong performance. A small minority are in H2 and H3, typically due to early units approaching mid-life. These relays continue to provide dependable service, with renewal planning scheduled around their 25-year expected life.

The management of protection relays combines routine testing, condition monitoring, and targeted renewal strategies. These strategies recognise the different characteristics of electromechanical, static, and digital relays, and aligns maintenance and renewal practices with their risk profiles.

- **Condition-based interventions:** Relay health is tracked through performance data, operational error logs, and results of periodic tests. Any relays showing anomalies or test failures are either refurbished (where economic) or replaced.
- **Digital relay management:** Modern relays are expected to deliver about 25 years of service. Their performance is monitored continuously through SCADA, and replacements are planned at end-of-life to avoid unexpected failures. Capacitor degradation in power supply circuitry is the most common late-life failure mode and is managed through proactive replacement.
- **Electromechanical and static relay phase-out:** These older technologies, with typical service lives of 30 to 40 years, are being systematically replaced with digital relays. Renewal is prioritised at substations where protection schemes require modern features or where reliability and safety risks are highest.
- **Routine testing and inspection:** All relays are subject to four-yearly protection system testing, covering trip circuits, breaker trips, and measuring circuits. Digital relays are additionally self-monitoring but remain included in this testing cycle to ensure whole-system integrity.

- **Safety and compliance:** Advanced functions available in modern relays, such as arc-flash detection, provide an additional layer of safety. All new installations are required to comply with relevant safety in design processes and industry standards.

The asset management strategies ensure relays remain reliable in protecting assets, personnel, and customers, while also keeping maintenance efficient and supporting the broader transition toward full digitalisation of the protection fleet. Protection relay renewal decisions are then guided by a mix of condition, age, and technological obsolescence. Unlike mechanical plant, relays are strongly influenced by the pace of electronic development, meaning replacement is often triggered by functionality and supportability rather than outright physical failure. Renewal triggers include:

- **Condition:** Failed test results, nuisance tripping, or unreliability in clearing faults.
- **Economics:** Where the cost of maintaining older relays outweighs the benefit compared to replacement with modern digital devices.
- **Safety and resilience:** Inability to deliver advanced features such as arc flash detection, duplicate protection, or fast fault clearing, which are increasingly required for safe operation.
- **Technology and obsolescence:** Lack of manufacturer support, limited spare parts, or inability to integrate with SCADA and modern protection schemes.

In broader planning terms, relay renewal supports resilience objectives by ensuring protection systems remain fast, selective, and coordinated. As load growth, distributed generation, and climate-related risks increase network complexity, modern digital relays provide the flexibility to adapt protection settings, reducing fault impacts on customers while maintaining safety. Over the next 10 years, the remaining static and electromechanical relays will be progressively replaced. Digital relays, which already comprise the majority of the fleet, will be managed to align with their expected 25-year lifecycle, with renewals phased to avoid large-scale concurrent replacement when these units approach end-of-life.

Disposal practices follow electronic waste management standards. Obsolete units are decommissioned and sent for certified recycling, with hazardous materials handled by approved contractors. Where practical, working units may be retained as interim spares to support the fleet until full replacement.

### Bulk metering

#### Network insights

Bulk metering provides the accuracy and assurance needed for both billing and operational decision-making. By integrating check meters across our substations, we gain real-time visibility of energy flows, ensuring regulatory compliance and supporting sound investment planning. These systems help us verify supply performance, maintain fairness for customers, and strengthen confidence in network data. What was once a basic accounting tool now plays an important role in network resilience and planning for future demand.

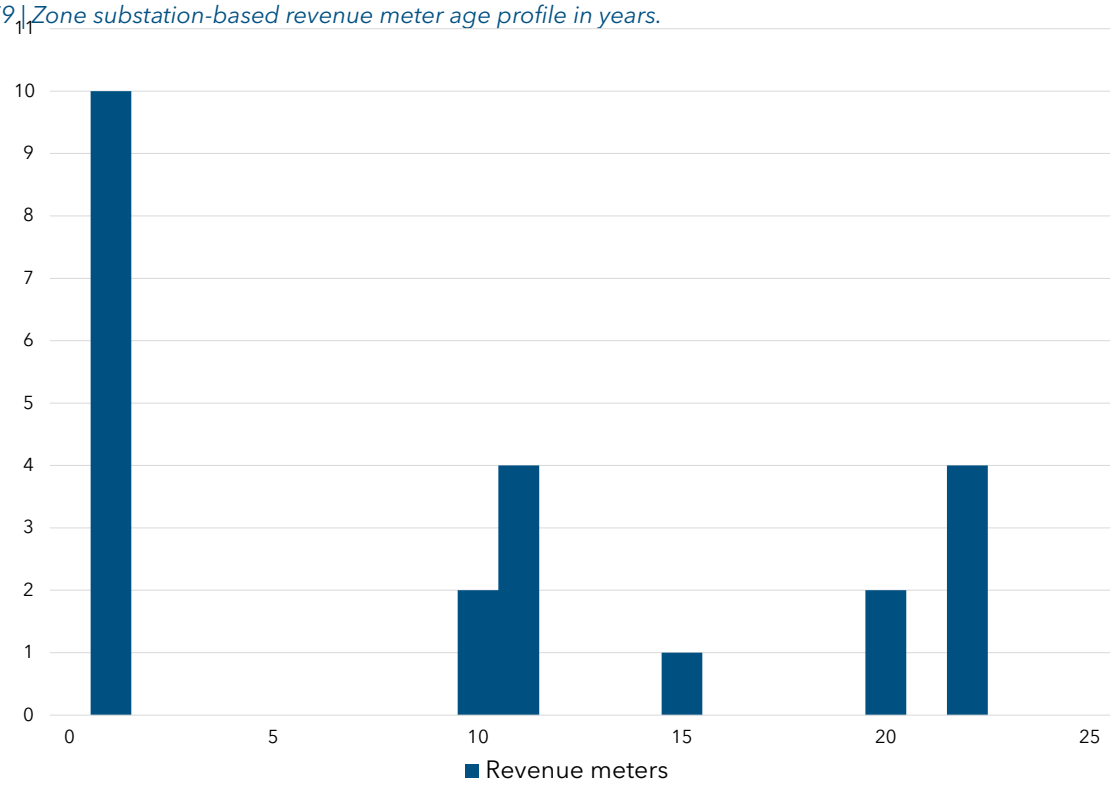
Bulk metering at zone substations provides the measurements needed for accurate billing, verification of energy supplied at higher voltage levels, and operational monitoring. Revenue meters ensure billing accuracy and compliance with the Electricity Industry Participation Code, while check meters validate energy flows and provide remote monitoring through SCADA.

The bulk metering fleet is relatively small, comprising eight revenue meters and six check meters installed at selected zone substations. Revenue meters are used for billing customers supplied directly at 11kV, while check meters provide operational assurance and support system planning. Table 44 and Figure 79 show the age profile of revenue meters, with half of the fleet between 16 and 20 years old and the remainder between 5 and 15 years old. This indicates that while most units remain within their expected 20-year service life, several will require replacement within the planning period.

*Table 44 | Zone substation revenue metering population.*

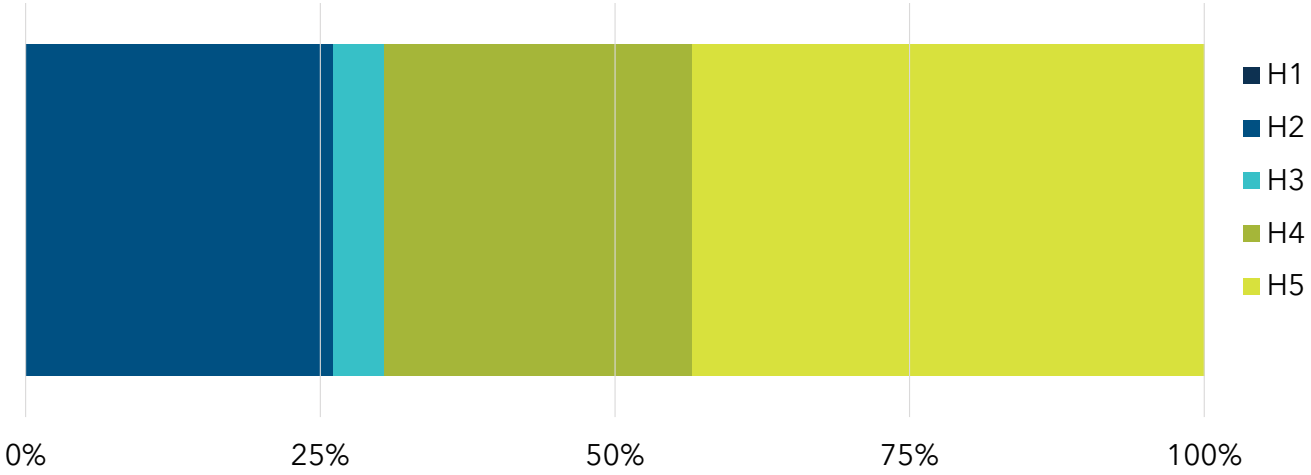
| Age (Years) | Number | % of total |
|---|---|---|
| 5 to ≤ 10 | 2 | 25% |
| 11 to ≤ 15 | 2 | 25% |
| 16 to ≤ 20 | 4 | 50% |
| **TOTAL** | **8** | **100%** |

*Figure 79 | Zone substation-based revenue meter age profile in years.*




The age-based asset health profile in Figure 80 guides replacement planning. Around one quarter of the fleet is in H2, reflecting moderate ageing and nearing end of life. A small proportion is in H3, with reduced expected service life. The remainder is in H4 and H5, where meters are assessed as good to very good and expected to perform reliably for at least another decade. This information is used to schedule replacements and ensure compliance with regulatory requirements.

*Figure 80 | Zone substation-based revenue meter asset health as of 2022/23*



Although bulk meters do not directly influence continuity of supply, they remain essential for financial accuracy, regulatory compliance, and sustaining customer trust. By validating energy flows, they also provide the foundation for accurate system analysis and informed operational decision-making, which in turn supports network planning and strengthens resilience.

Operation and maintenance of bulk metering assets are governed by regulatory requirements and delivered in close coordination with Metering Equipment Providers (MEPs). Revenue meters are maintained and certified by MEPs under the Electricity Industry Participation Code to ensure accuracy and adherence to industry standards. When failures occur, MEPs manage calibration or replacement, while we facilitate access and coordinates activities to minimise disruption. Check meters, integrated with SCADA, provide continuous monitoring and operational oversight, enabling early identification of issues and timely responses.

Replacements are scheduled alongside substation projects to reduce cost, avoid unnecessary outages, and ensure efficient delivery. This lifecycle-based approach maintains accuracy and reliability, while establishing a consistent standard across the network. All installations are designed, tested, and certified to meet wiring code standards, ensuring that risks to staff during inspection or replacement are minimised and safe working conditions are maintained.

Revenue meters are designed for service lives of around 20 years, while check meters are equipped for SCADA integration to enhance operational resilience. Together, they underpin accuracy, efficiency, and reliability by ensuring fair billing, preventing disputes, and maintaining confidence in supply arrangements.

## Load control injection plant

Load control injection plants deliver us the means to shape electrical demand by transmitting "ripple" signals through the network. These signals switch appliances such as hot water systems, space heating, and in some areas irrigation pumps. By shifting or curtailing non-critical demand, the plants smooth peak loads, delay the need for network reinforcement, and support network stability.

Injection plants play an important part in resilience, especially as distributed energy resources and variable generation make demand patterns less predictable. The fleet is concentrated at key substations across the region, with six upgraded to modern static designs and one still relying on a legacy rotary design. By maintaining and operating these assets, we ensure that peak demand is kept within capacity, supply remains secure during stress events, and costly upgrades to distribution or transmission networks can be deferred. The objectives listed in Table 45 link the Injection plant fleet to our broader resilience and efficiency goals.

*Table 45 | Zone substation revenue metering population.*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Ensure all installations meet safety-in-design requirements and comply with wiring and earthing standards.<br>Maintain safe access for staff and contractors during operation and servicing. |
| **Customer service levels** | Use ripple control to manage peak demand and maintain supply security.<br>Provide reliable signalling to support customer appliances and avoid unnecessary interruptions. |
| **Cost** | Apply lifecycle planning to align replacements with substation projects and minimise cost.<br>Maintain contracts for servicing and spares to optimise efficiency. |

| | |
|---|---|
| **Community** | Support wider energy efficiency and load management goals by deferring costly upgrades and reducing the need for peaking generation.<br>Ensure installations integrate well within substations to minimise local impact. |
| **Asset management capability** | Maintain accurate fleet data in the EAM and GIS systems.<br>Train staff and contractors in operating and maintaining both legacy and modern ripple equipment.<br>Monitor emerging smart meter–based control technologies as potential future alternatives. |

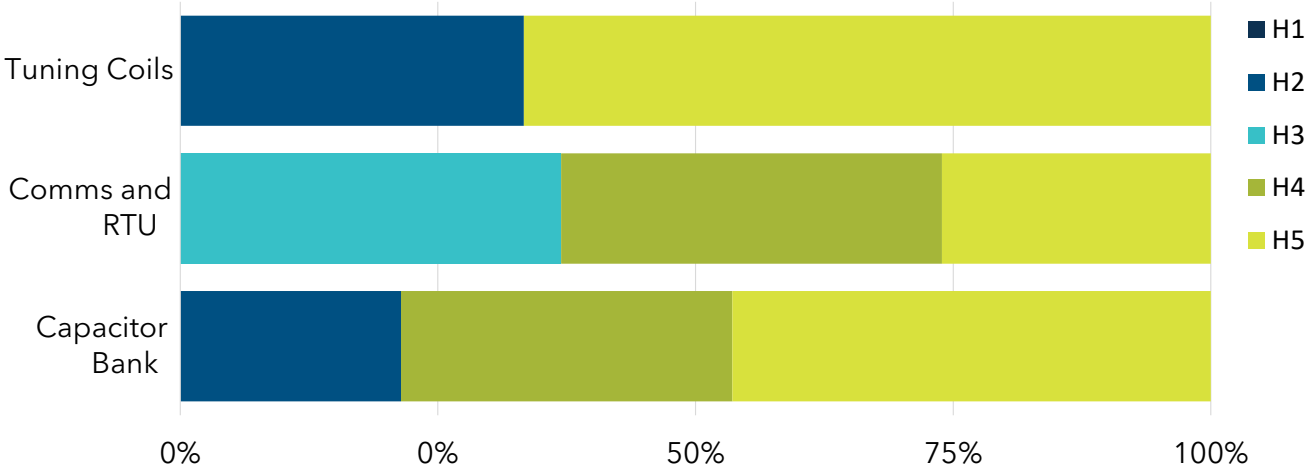
## Demand-shaping for a smarter network

Our load control injection plants allow us to actively manage electricity demand across the network by sending ripple signals to control appliances such as hot water systems and irrigation pumps. These systems help smooth peak load periods and strengthen resilience as variable demand approaches network capacity. They also defer costly upgrades that would otherwise be needed to expand supply. By maintaining these plants and aligning their renewal with our substation programme, we ensure that load control remains effective, supply security is maintained, and the network continues to adapt to a changing energy landscape.

The AHI for the load control injection fleet is shown in Figure 81. The AHI considers the design three main components of the load control injection plants:

- **Tuning coils:** Tuning coils ensure that ripple signals are effectively coupled into the network by matching the injected signal to the network. Their condition is primarily influenced by insulation integrity, mechanical wear on connections, and environmental exposure within the substation. The AHI profile shows a mix of H2 and H5 ratings. While most tuning coils are in very good health, a small proportion is showing signs of age and will require close monitoring to ensure signal strength remains consistent.
- **Capacitor banks:** Capacitor banks amplify the signal to the network. Capacitor banks also provide the reactive power needed to drive ripple signals. Their condition is tracked through insulation resistance testing and thermal performance checks. The AHI profile shows most units in H4 and H5, with a minority in H2. This indicates that, although the majority are performing well, some older capacitors are entering a phase where deterioration of dielectric materials may increase the risk of failure, prompting staged replacement. and provide the reactive power needed for signal strength,
- **Control systems with RTUs:** Controllers and RTUs (Remote Terminal Units) manage signal injection and integrate the plant into SCADA. Their condition is assessed through communication reliability, error rates, and compatibility with modern systems. The AHI profile indicates that a portion of this fleet sits in H3, with the remainder in H4 and H5. This reflects the presence of older RTUs nearing the end of their useful life. These units pose an increasing risk to interoperability and cyber resilience, and their eventual replacement with modern digital controllers is planned.

*Figure 81 | Load control injection plant asset health*




Overall, the AHI profile confirms that most of the fleet is in good health, with recent investment in electronic plants strengthening long-term reliability. The residual risk lies mainly with older capacitor units and outdated RTUs, which are already prioritised for staged renewal. These findings reinforce the importance of ongoing diagnostic testing and targeted replacement to maintain effective load control capability across the network.

Load control injection plants require specialised maintenance to ensure their continued effectiveness in managing peak demand and supporting system stability. While modern electronic plants are relatively low-maintenance, their performance still depends on regular inspection, calibration, and diagnostic testing. Legacy units, particularly rotary plant and ageing communications equipment, require closer oversight to mitigate reliability risks.

- **Routine inspections:** All plants are subject to annual inspections, including checks on external housings, signal injection levels, and operational status. These inspections confirm that tuning coils, capacitor banks, and controllers are functioning correctly and remain safely integrated into substation systems.
- **Diagnostic testing:** Every five years, detailed diagnostic tests are undertaken. These include resonant frequency checks on tuning coils, insulation resistance testing, and verification of ripple signal levels to ensure compliance with operational standards.
- **Specialist servicing:** Due to the unique nature of ripple control, our business maintains service contracts with specialist providers. These contracts cover annual inspections, supply of critical spares, and access to technical expertise for both modern and legacy systems. The arrangement ensures rapid response to failures and continuity of service across the fleet.
- **Integration with substation operations:** Maintenance tasks are coordinated with broader substation programmes to minimise outages and reduce costs.

The renewal of load control injection plant is guided by both condition and technology suitability. Modern electronic plants are expected to deliver reliable service lives of 25 to 30 years, provided they continue to pass diagnostic and performance tests. These assets will be retained in service until condition assessments or operational changes trigger replacement. The Tekapō rotary unit is the final legacy plant in the fleet and operates on a 500 Hz ripple frequency, which is no longer standard. While it still performs reliably for a small number of customers, spares and manufacturer support are now scarce. The plant will be allowed to operate until it reaches end of life, after which it will be decommissioned. Its load control function will be transferred to smart meters and programmable ripple relays, which provide equivalent capability without the need to reinvest in obsolete technology.

For electronic plants, renewal planning is integrated with substation refurbishment programmes to align costs and minimise disruption. Units nearing end of life are replaced with new ripple plants operating on the DECABIT standard (317 Hz), ensuring consistency across the fleet and compatibility with modern relays. Remote Terminal Units (RTUs) associated with ripple plants are renewed in line with communications upgrades, ensuring ongoing SCADA integration.

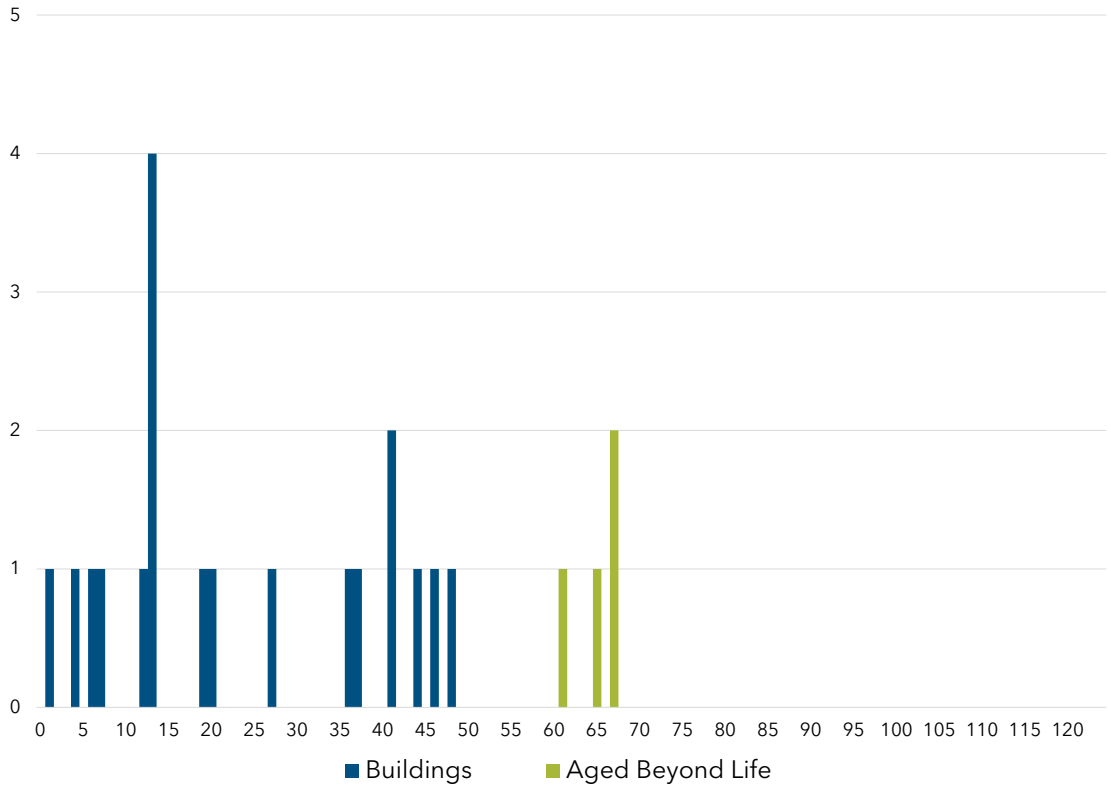
Disposal practices reflect both environmental and operational responsibilities. Electronic components are processed through e-waste recycling channels, while metallic components such as tuning coils and capacitor banks are reclaimed where possible. Rotary plant decommissioning will involve safe disposal of oil-filled parts, ensuring no environmental contamination.

## Buildings

Zone substation buildings provide the secure, functional environments required to house protection, SCADA, communications, indoor switchgear, and in some cases, load control equipment. Their role is to safeguard critical infrastructure from environmental exposure, seismic activity, fire, vermin, and vandalism, ensuring assets remain operational throughout their service lives.

Well-designed and maintained buildings strengthen network resilience by protecting equipment from external risks and enabling safe, reliable access for staff. They also support continuity of supply by ensuring sensitive assets operate under controlled conditions, regardless of weather or seismic events. Figure82 shows the distribution of our zone substation building fleet by age, reflecting both the presence of long-serving legacy structures and recent growth-driven investments in modern facilities.

*Figure 82 | Zone substation buildings age profile in years.*




We currently operate 25 buildings across our zone substations. These are constructed from a mix of steel-reinforced concrete, insulated steel panel, and timber-frame designs, reflecting different eras of development and investment. Five buildings are less than 10 years old, while a further eight fall in the 11–20 year age range,. At the other end of the spectrum, four buildings are more than 60 years old.

This distribution highlights two key trends: a growing proportion of modern, standardised facilities providing reliable service, and a small group of ageing legacy structures that require closer monitoring. Table 46 summarises the building population by age group.

*Table 46 | Zone substation building population.*

| Age (Years) | Number | % of total |
|---|---|---|
| **≤10** | 5 | 21% |
| **11 to ≤20** | 6 | 25% |
| **21 to ≤30** | 2 | 8% |
| **31 to ≤40** | 2 | 8% |
| **41 to ≤50** | 5 | 21% |
| **51 to ≤60** | 0 | 0% |
| **61 to ≤70** | 4 | 17% |
| **TOTAL** | **24** | **100%** |

The overall condition of our zone substation buildings is generally good, with most assets either new or refurbished as part of recent growth-driven projects. A smaller group of legacy buildings, many of which are timber-frame structures, require ongoing maintenance to remain serviceable. Recent inspections have confirmed that our buildings remain within seismic design limits. However, older structures are inherently less resilient to major seismic events, such as the Alpine Fault scenario. This risk is being actively reviewed to ensure continuity of operation in the event of a large earthquake.

Fire, vandalism, and unauthorised access are additional risks managed through secure construction, regular inspection, and, where necessary, upgrades to fencing and access control systems. Collectively, these measures ensure that substation buildings continue to support the resilience of the wider network while protecting staff and critical equipment.

New substation buildings are designed with layouts that balance practicality, safety, and adaptability. Internal spaces are arranged to separate control, protection, and communications equipment from higher-voltage switchgear areas, reducing operational risk and simplifying maintenance. Aesthetic treatment is applied at urban sites to ensure buildings integrate with their surroundings, reducing visual impact and maintaining community acceptance.

The ongoing management of substation buildings focuses on ensuring they remain functional, secure, and aligned with the needs of the equipment they house. Monthly preventive inspections are carried out to identify condition related risks at our buildings. Maintenance tasks are scheduled in line with both condition observations and broader substation works. For example, refurbishment of a building may be aligned with transformer or switchgear replacement, ensuring cost efficiency and minimising repeated disruption. Routine housekeeping includes vegetation control around buildings, vermin checks, and ensuring fire safety equipment remains serviceable.

Renewal decisions for zone substation buildings are based on structural condition, compliance with current safety and seismic standards, and their ability to continue providing suitable accommodation for protection, control, and switchgear equipment. Buildings are not replaced simply because of age; instead, refurbishment or renewal is triggered when the costs of maintaining fitness-for-purpose outweigh the benefits of retention.

Most modern buildings, constructed from reinforced concrete or insulated panel systems, have service lives extending well beyond 50 years if maintained appropriately. Refurbishment cycles typically involve resealing joints, replacing roof structures, upgrading fire systems, or reconfiguring layouts to suit modern equipment. This extends life at relatively low cost and avoids replacement.

Legacy timber-framed or asbestos-clad buildings are managed differently. These assets are nearing the end of practical life, with limited resilience to seismic events and higher maintenance needs. Where safe management of asbestos is no longer feasible, or where functional

requirements cannot be met, full replacement is scheduled. Temporary or containerised buildings may be used as interim solutions where timing of major projects requires flexibility.

## Spare and mobile capacity

Spare and mobile assets provide critical backup capacity across the network, ensuring that planned and unplanned outages can be managed without compromising supply. This fleet includes a mobile substation and a range of diesel generators, which together provide flexibility to maintain service continuity during substation maintenance, major equipment failure, or emergency events.

The mobile substation replicates the key functions of a fixed zone substation, with a 9 MVA transformer, associated circuit breakers, and full protection systems. It can step down from 33 kV to 11 kV or operate as a step-up transformer, enabling supply to be maintained while permanent equipment is removed from service. This capability is central to supporting resilience, particularly at rural substations with a single transformer.

Standby generators supplement this capacity by providing temporary supply at lower voltages. They are primarily used to support customers during prolonged outages or to maintain essential services when local infrastructure is unavailable. Table 47 summarises the mobile generation fleet.

*Table 47 | Mobile generation fleet details*

| Number | Size | Connection voltage |
|---|---|---|
| **2** | 810kVA | 400V or 11kV |
| **1** | 550kVA | 400V |
| **1** | 400kVA | 400V |
| **1** | 275kVA | 400V |
| **1** | 150kVA | 400V |
| **6** | 6.5kVA | 230V |

The main risks associated with this fleet lie not in their present condition but in the consequences of failure during deployment. A fault in the mobile substation could delay major maintenance or force unplanned outages, while generator failure could compromise supply security during planned works or emergencies. To mitigate these risks, assets are subject to proactive servicing. Routine maintenance ensures the readiness of both the mobile substation and the generator fleet. Generators are serviced each year, with operational and condition testing carried out alongside oil changes and calibration to confirm reliability. Their trailers are also inspected annually and issued with a warrant of fitness to ensure they remain roadworthy and safe for deployment.

To maintain performance, every generator is run under load for 20 to 30 minutes each year. This practice exercises the internal components and prevents wet stacking, a condition that can occur when diesel engines operate without sufficient load. Visual checks are also performed on belts, hoses, and air intake and exhaust systems to detect any signs of deterioration before they develop into failures.

The mobile substation undergoes its own programme of regular inspection and functional testing. These checks verify the performance of protection systems, switching capability, and transformer operation, ensuring that the unit can be relied upon when called into service. Together, these measures ensure that our spare and mobile assets remain immediately deployable and effective under operating conditions.

## Distribution transformers

Distribution transformers connect our low-voltage supply system to our high voltage supply system, stepping down electricity from 11 kV to levels suitable for households, farms, and businesses. They provide the final link between the distribution network and end-use customers, ensuring voltage is delivered within safe and reliable limits. Their performance is directly tied to the quality of service, with failures or poor condition leading to outages, equipment damage, or safety risks.

The fleet encompasses pole-mounted transformers, ground-mounted transformers, and specialised units such as voltage regulators. Pole-mounted units, common across rural and semi-rural areas, typically serve smaller groups of customers and are exposed to weather and third-party risks. Ground-mounted units, generally found in suburban and CBD areas, are larger, more costly, and supply critical or high-density loads. Specialised assets such as voltage regulators improve power quality on long rural feeders, ensuring voltage stability where distance would otherwise compromise supply.

### Demand-shaping for a smarter network

We expect to invest $31 million in our distribution substations over the next decade. This investment focuses on improving safety, protecting the environment, and maintaining condition across our transformer fleet. Distribution transformers connect our 400V low-voltage customers to our high-voltage 11 kV network. They form the final link to supply homes, farms, businesses, and other customers with electrical energy. We monitor transformer conditions through inspections and thermal checks, replacing assets just before failure to maintain reliability. Oil leaks are repaired promptly to prevent contamination, and new installations meet modern safety and environmental standards. This proactive approach ensures dependable supply and supports a resilient, future-ready network.

Resilience in this fleet is achieved by designing for long service lives, responding quickly to failures, and prioritising replacement where condition, environmental risks, or load growth present the highest threat to safety or reliability. Because all distribution transformers are oil-filled, environmental management is key to their operation, requiring prompt action on leaks and careful end-of-life handling to mitigate fire and contamination risks.

Our management of distribution transformers balance safety, service reliability, cost efficiency, and community expectations. Our portfolio objectives, shown in Table 48, guide both day-to-day maintenance and long-term renewal planning, ensuring transformers continue to meet operational and environmental standards.

*Table 48 | Distribution transformer portfolio objectives*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Promptly action all oil leaks and remediate contaminated soil.<br>Apply herbicides safely to protect staff and the environment. |
| **Customer service levels** | Replace failed pole-mounted transformers within 24 hours.<br>Monitor and assess ground-mounted transformers through inspections to guide timely replacement and minimise outages. |
| **Cost** | Deliver fit-for-purpose installations and prioritise cost-effective design, construction, and replacement strategies. |
| **Community** | Consider the placement of new substations to minimise disruption and visual impact.<br>Engage with communities on the location of larger installations where appropriate. |
| **Asset management capability** | Implement inspection and maintenance programmes in the enterprise asset management system.<br>Maintain accurate records of transformer condition and performance to support decision-making. |

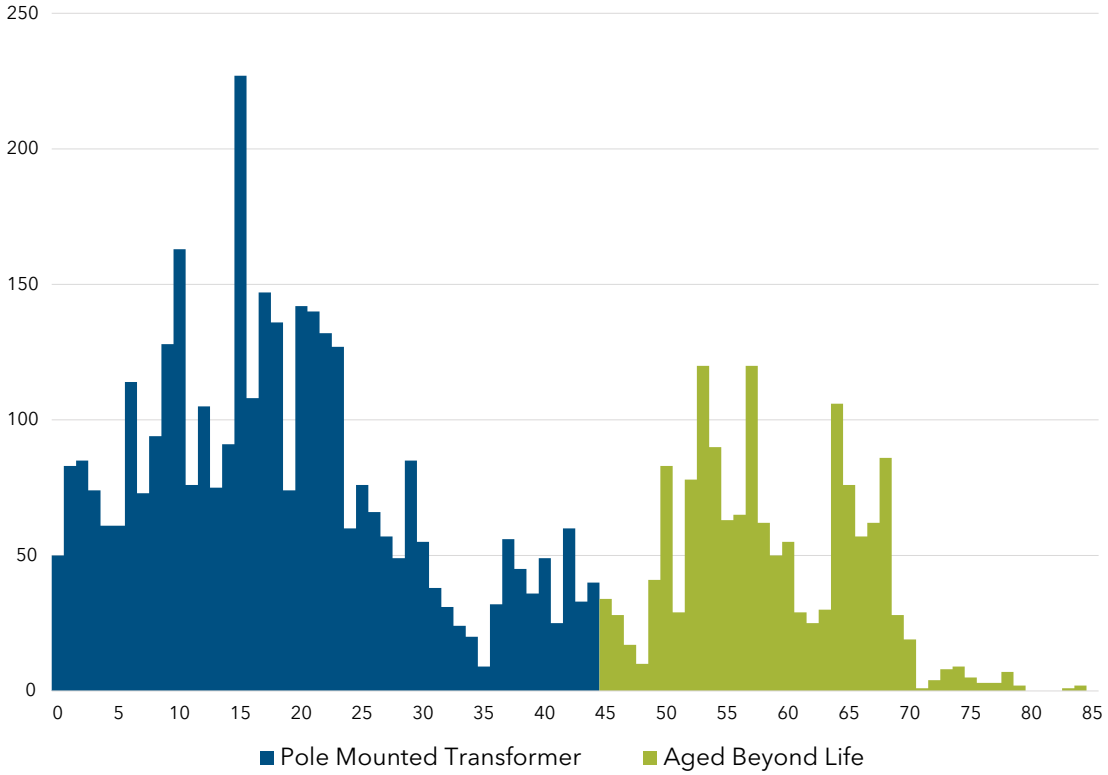
We currently operate 6,263 oil-filled distribution transformers across the network. Their capacity distribution is summarised in Table 49. The largest group is transformers rated at 15 kVA or below, which account for nearly 43% of the fleet. These units are typically pole-mounted and serve small rural clusters. Transformers rated between 15 and 100 kVA make up a further 19% of the population, supporting both suburban and rural supply. Larger ground-mounted transformers above 100 kVA, though fewer in number, represent a critical part of the portfolio due to their role in supplying dense urban loads and industrial sites.

*Table 49 | Distribution transformer population by rating*

| Rating | Number | % of total |
|---|---|---|
| **≤ 15kVA** | 2691 | 43% |
| **>15 and ≤ 30kVA** | 1193 | 19% |
| **>30 and ≤ 100kVA** | 1089 | 17% |
| **>100 and ≤ 250kVA** | 637 | 10% |
| **>250 and ≤ 500kVA** | 466 | 7% |
| **>500 and ≤ 1500kVA** | 187 | 3% |
| **TOTAL** | **6,263** | **100%** |

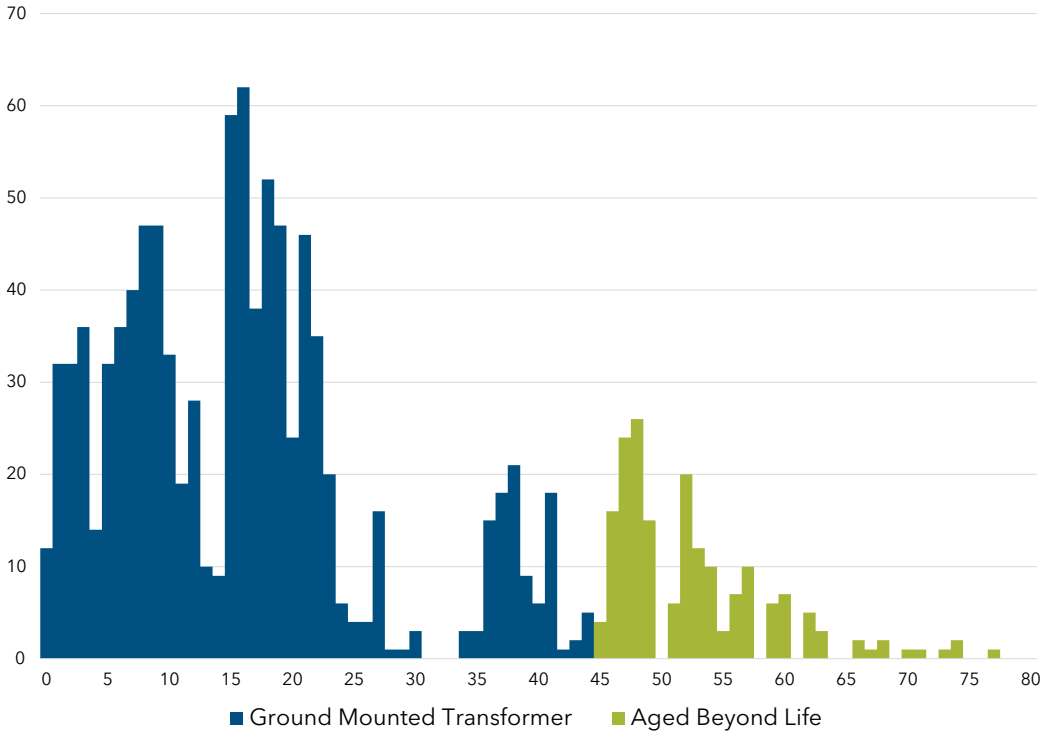
The age profile of pole-mounted transformers, shown in Figure 83, broadly mirrors that of the overhead line fleet they are attached to. While most units are less than 30 years old, there is a long tail of assets that have been in service for more than 60 years. Although many remain in good condition, they are the most exposed to weather, lightning, and vehicle strikes. Their relative vulnerability makes them more likely to fail suddenly, particularly during storm events, even when condition inspections show no obvious defects. For this reason, pole transformer replacements often occur reactively.

*Figure 83 | Pole mounted distribution transformer age profile in years.*



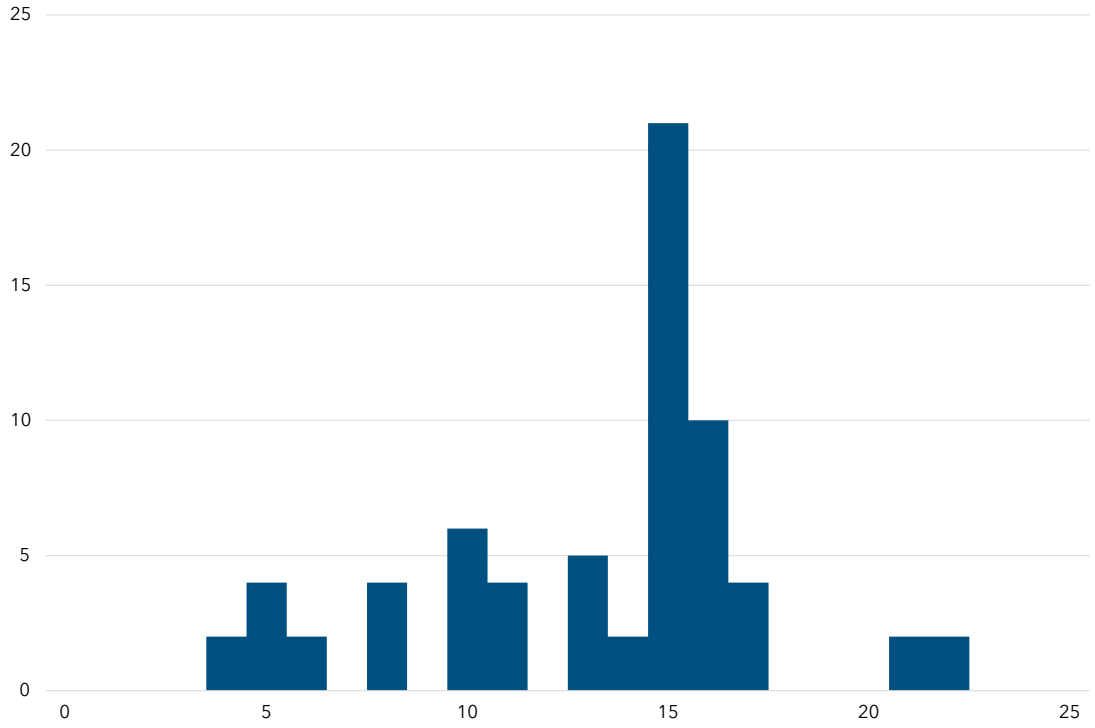

Ground-mounted transformers, illustrated in Figure 84, are generally younger, reflecting more recent investment in urban substations and industrial load growth. A large proportion were added during the 2000s and 2010s, supporting urban substation upgrades and industrial expansion, particularly in Timaru and nearby growth areas. This younger profile indicates strong investment over the last two decades, with most assets expected to remain in serviceable condition well within their standard lifecycle. The condition of ground-mounted transformers is more closely monitored, with any oil leaks or structural deterioration prioritised for remediation. These assets are less likely to fail outright but present greater consequence if they do, given their role in supplying clusters of customers or sensitive industrial loads.

*Figure 84 | Ground-mounted distribution transformer age profile in years.*



Voltage regulators, summarised in Figure 85, are a much smaller population, with 34 sites in service. These installations are relatively young, with the majority commissioned in the past 20 years to support rural irrigation and dairy conversions. The age profile highlights a fleet that is well within expected service life, consistent with benchmark life expectancy of 55 years. Voltage regulators present specific operational risks tied to their electronic controllers and moving contacts. Their condition is tracked through scheduled servicing, with failure risks centred on controller faults or wear from frequent switching. Because regulators are critical to maintaining voltage quality on long rural feeders, their ongoing performance has a direct impact on service reliability for customers in those areas.

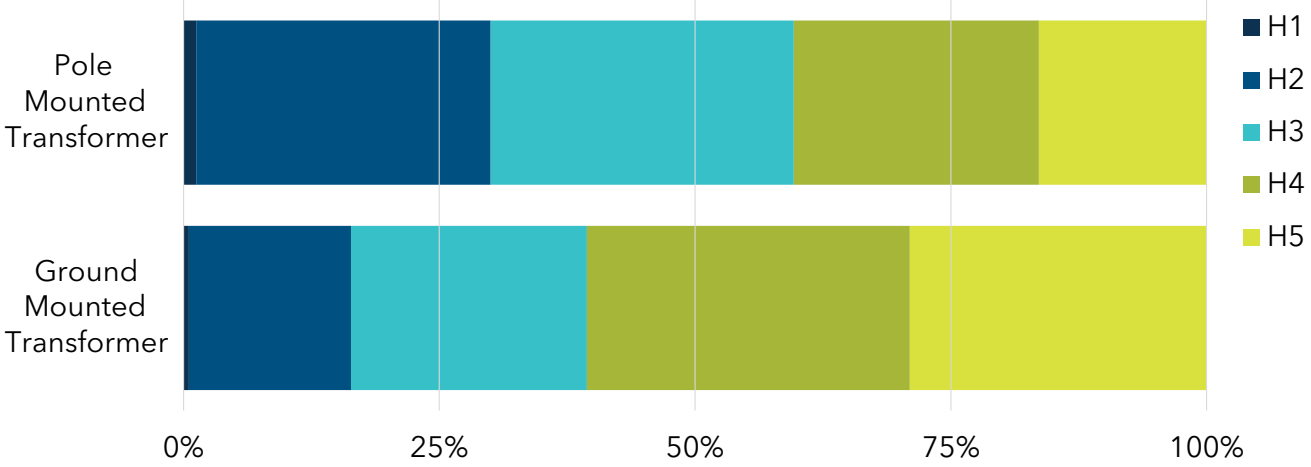
*Figure 85 | Voltage regulator age profile in years.*




The asset health profile for distribution transformers, shown in Figure 86, highlights the difference in condition between pole-mounted and ground-mounted units. Pole-mounted transformers present a wider spread across health categories, with notable concentrations in H2 and H3. These reflect ageing units that, while still operational, are approaching the limits of their expected service life and carry increased exposure to failures from lightning strikes, weather events, and third-party damage. A smaller proportion lies in H1, representing the most deteriorated units that will require renewal in the short term.

Ground-mounted transformers are generally in stronger condition, with the majority clustered in H4 and H5. These assets benefit from more recent investment in urban and industrial areas, as well as greater protection from environmental exposure. A minority of units fall within H2 and H3, indicating the presence of older substations where proactive monitoring is required to mitigate risks of oil leaks, corrosion, or electrical faults.

*Figure 86 | Distribution transformer asset health as of 2022/23.*




Taken together, the AHI profile shows that while the fleet remains broadly sound, targeted renewal is essential for the older pole-mounted population. Transformers are manufactured in line with standards, allowing operation beyond their nominal service lives, however performance is shaped by age, exposure, and external risks. Condition is assessed through visual inspections, thermal scanning, oil leak detection, and bushing evaluations, with more detailed checks for larger ground-mounted units. Prioritising transformer replacements on both age and condition reduce operational risk, safeguard reliability, and maintain confidence in both rural and urban supply.

Distribution transformers are designed and constructed to international standards, ensuring resilience under a wide range of network and environmental conditions. All new units are specified to AS/NZS 60076 and AS 2374, giving assurance of safety, quality, and performance. Oil-filled transformers remain the standard design, but we are considering environmentally safer alternatives such as natural ester fluids where feasible, reducing fire and contamination risks.

Pole-mounted installations follow standardised designs, allowing consistent construction, safe clearances, and efficient replacement practices. Larger two-pole substations are assessed for seismic strength, with relocation to ground level considered where stability or access presents risks. Ground-mounted transformers are built to withstand higher fault duties and supply critical loads, and all new pad-mount installations are designed by chartered engineers to meet earthquake resilience standards.

In specifying transformer capacities, we account not only for current demand but also for forecast growth in electric vehicles, distributed solar generation, and urban infill. This forward-looking design philosophy minimises the need for frequent upgrades and reduces lifecycle costs, while ensuring headroom for peak demand events. Forecast replacement volumes indicate around 135 units replaced annually across all classes.

*Table 50 | Distribution transformer replacement/renewal program*

| Rating | Number | Annual Replacement |
|---|---|---|
| **≤ 15kVA** | 2691 | 60 |
| **>15 and ≤ 30kVA** | 1193 | 27 |
| **>30 and ≤ 100kVA** | 1089 | 25 |
| **>100 and ≤ 250kVA** | 637 | 15 |
| **>250 and ≤ 500kVA** | 466 | 11 |
| **>500 and ≤ 1500kVA** | 187 | 5 |
| **TOTAL** | **6,263** | **143** |

Distribution transformers require relatively low levels of maintenance compared with other network assets, but proactive inspection and monitoring remain essential to ensure reliability and safety. Pole-mounted units are assessed during overhead line inspections, where condition indicators such as oil leaks, corrosion, or damage from lightning and third-party impacts are identified. Most small pole-mounted units are run-to-failure given their low replacement cost, with failures typically managed through rapid response crews carrying spares.

Ground-mounted transformers undergo more detailed inspections because of their higher criticality and larger load profiles. Annual non-intrusive inspections check for oil weeps, bushing deterioration, corrosion, and environmental risks such as vegetation encroachment or flooding exposure. Thermographic scanning is used to detect hot-spots, while partial discharge testing supports early identification of insulation stress. Larger units connected to ring main units (RMUs) or high-value customer loads receive five-yearly servicing, including oil sampling, contact checks, and insulation resistance testing.

Voltage regulators are maintained on a four-year cycle, reflecting the need to test electronic controllers, moving contacts, and tap change mechanisms. Load and operational histories from smart meters and SCADA provide additional insights, enabling predictive intervention where abnormal performance trends are detected.

This structured inspection and servicing regime allows the extension of the service life of its transformer fleet, manage environmental risks from oil leakage, and ensure that capacity remains available where it is most needed. Overall, the fleet continues to perform well, with no systemic defects identified. The main risks arise from environmental exposure, age-related degradation, and operational stresses. Proactive monitoring and targeted renewal remain essential to mitigate failures, manage environmental impacts from oil leaks, and ensure resilience in the face of storms and growing network demands.

Standard transformer service lives are typically around 45 years, although many units continue operating well beyond this where condition allows. All retired transformers are drained of oil, with the oil recycled through certified processors to manage environmental risk. Scrap metal is recycled where feasible, and asbestos-containing components in older low-voltage panels are removed by licensed contractors.

## Distribution switchgear

Distribution switchgear is central to the safe, reliable, and flexible operation of the 11 kV distribution network. It enables sections of the system to be switched, isolated, or reconfigured to reduce the impact of faults and shorten outage durations. The portfolio consists of three main fleets: ground-mounted switchgear, pole-mounted switches, and pole-mounted circuit breakers, reclosers, and sectionalisers. Each fleet plays a distinct role in balancing operational simplicity with modern automation, together forming the backbone of switching capability across the network.
The portfolio objectives for our distribution switchgear fleet are summarised in Table 51.

*Table 51 | Distribution switchgear portfolio objectives*

| Asset management objective | Portfolio objective |
|---|---|
| **Safety & environment** | Prevent injuries from switchgear operation or failure.<br>Eliminate SF6 leaks through monitoring, maintenance, and compliant handling.<br>Avoid oil leaks from causing environmental contamination through monitoring and maintenance. |
| **Customer service levels** | Continue automation of reclosers and voltage regulators to improve reliability. Consider the use of low-cost automated devices as tie switches to reduce outage duration. |

| Asset management objective | Portfolio objective |
|---|---|
| **Cost** | Deliver cost-effective lifecycle management.<br>Ensure designs remain fit for purpose and targeted at reducing risk. |
| **Community** | Minimise disruption from planned and unplanned outages.<br>Provide timely outage notification to all affected customers.<br>Use social media to keep the community informed during unplanned outages. |
| **Asset management capability** | Develop structured maintenance programmes in the EAM system.<br>Capture and use condition data to inform future investment and renewal planning. |

The objectives balance safety, operational performance, and long-term efficiency. Public safety is prioritised through risk reduction and environmental management of $SF_6$. Service levels are strengthened by automation, particularly reclosers and regulators, which reduce SAIDI and SAIFI. Cost efficiency is supported through standardised design and coordinated renewals, while timely communication reduces customer impact. Embedding condition data into the EAM system underpins evidence-based decision-making and ensures renewals improve resilience.

## Demand-shaping for a smarter network

Distribution switchgear keeps our 11 kV network safe, reliable, and adaptable by allowing rapid fault isolation, switching, and restoration to reduce outage times. We plan to invest $18 million over the next 10 years to maintain and upgrade this critical equipment. Our focus remains on monitoring SF6 and oil-insulated units, expanding automation through key reclosers and tie switches, and using condition data to renew assets before failure.

The distribution switchgear portfolio is best understood by considering its three main fleets, each serving distinct functions within the network:

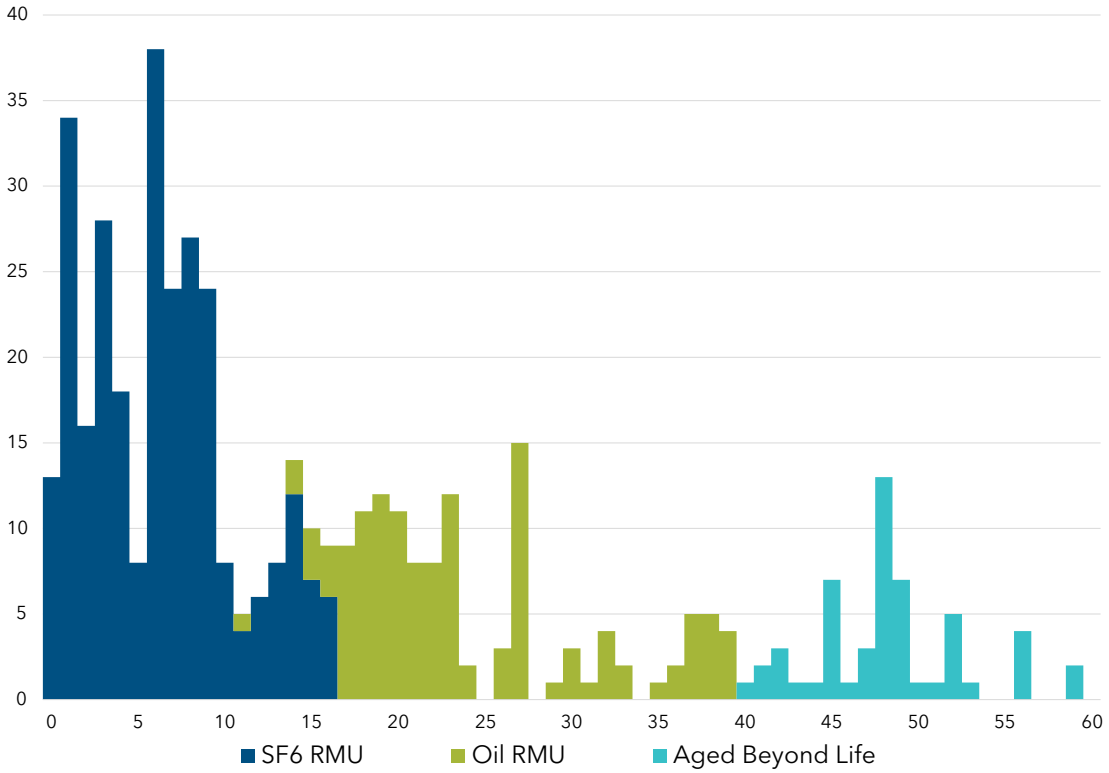
- **Ground-mounted switchgear:** Includes RMUs, fuse switches, and links associated with underground cable networks.
- **Pole-mounted switches:** Consist of drop-out fuses, air-break disconnectors, and links that dominate the 11 kV overhead network.
- **Circuit breakers, reclosers, and sectionalisers:** Provide advanced protection and automation on the overhead network.

### Ground-mounted switchgear

Ground-mounted switchgear, including Ring Main Units (RMUs), fuse switches, and links, forms part of underground cable networks in urban and industrial areas. These assets often supply large groups of customers, making their reliability vital for service continuity. The fleet comprises both oil-insulated and SF6-insulated RMUs, with SF6 now established as the standard for new installations because of its reliability, safety features, and compact design.

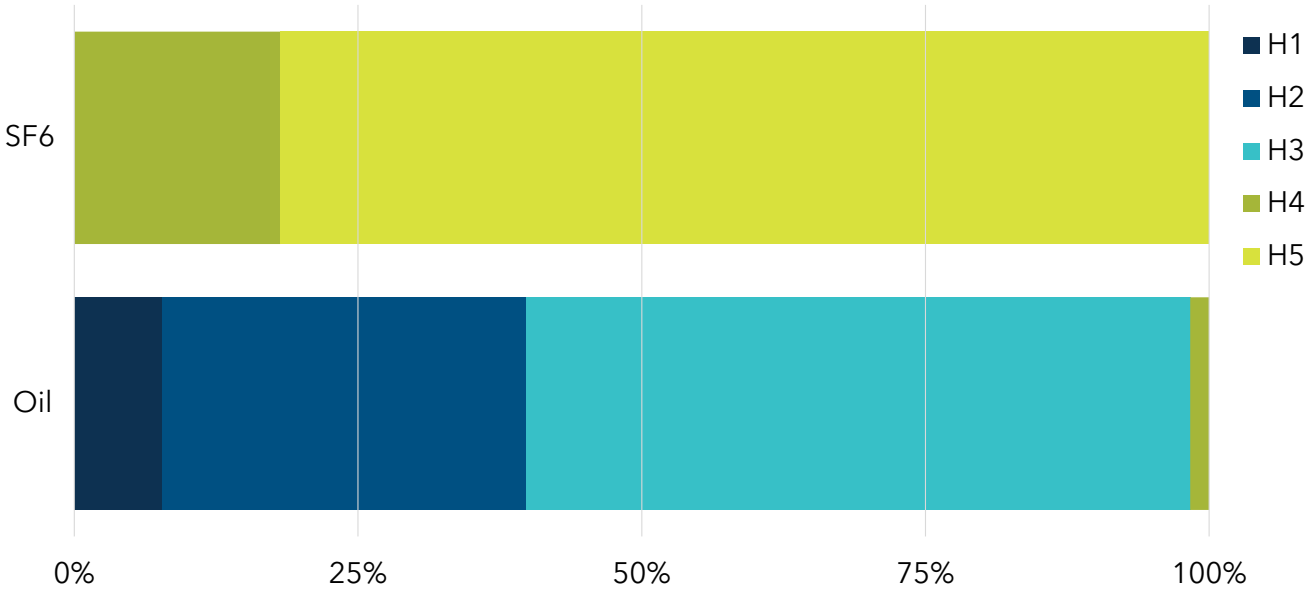
Population and age statistics confirm that there are 462 RMUs in service, consisting of 220 oil-insulated units and 242 SF6 units. The age distribution of these assets is illustrated in Figure 87. Most SF6 equipment is less than 15 years old, reflecting recent investment and the adoption of this technology as the default option. By contrast, several oil-insulated units are at or beyond their expected 40-year service life. While these older designs remain serviceable, they pose elevated operational risks, particularly in relation to oil leaks and fire hazards.

*Figure 87 | RMU age profile in years.*




Condition assessments indicate that older oil-filled units are more vulnerable to defects and insulation breakdown, while the SF6 fleet is generally in good condition. Asset health indicators, presented in Figure 88, show oil RMUs spread across H1 to H3, reflecting their ageing condition and associated risks. In contrast, most SF6 units sit in H4 and H5, confirming strong health and resilience across the newer portion of the fleet.

*Figure 88 | RMU asset health.*




Design standards have shifted toward a limited range of modern SF6 RMUs. These units feature compact layouts, arc-flash protection, and safer cable termination practices. The design also incorporates improvements in access for functional testing, enabling condition-based maintenance to be integrated into routine inspection cycles.

Maintenance practices are structured to reflect both the technology and the operating risks of each RMU type. All RMUs undergo an annual condition inspection to confirm operational integrity

and identify emerging defects. In addition, a six-monthly programme of partial discharge testing is carried out across the fleet to detect insulation stress at an early stage. Where partial discharge is identified, those units are monitored monthly to track changes in condition and to reduce the likelihood of in-service failure. Servicing intervals differ by design, as SF6 RMUs are serviced every seven years, and oil-filled RMUs receiving a full service every four-years.

Renewal planning is guided by condition and criticality. Oil units are being phased out in a structured programme, with replacements based on condition or coordinated alongside distribution substation projects. The fleet is progressively moving to a standardised SF6 base, ensuring consistency in performance and safety. Decommissioned oils are drained and recycled by certified processors, while SF6 is recovered and handled by licensed contractors, ensuring environmental and regulatory compliance.

## Pole-mounted switches

Pole-mounted switches, including drop-out fuses, air-break switches (ABS), and isolating links, are the most widespread devices on the 11 kV overhead network. Their role is both simple and essential: they provide isolation points that allow faults to be sectionalised and protect pole-mounted transformers that typically serve small groups of customers.

The age profile of pole-mounted fuses, shown in Figure 89, reveals a large population of younger assets installed in the last 20 years, but also a significant tail of units more than 50 years old. These older devices remain in service but carry higher failure risk, particularly under heavy fault conditions. Pole switches, illustrated in Figure 90, show a generally younger fleet, with most units under 20 years of age, although a small group remains in service beyond 50 years.

*Figure 89 | Pole fuse age profile in years.*

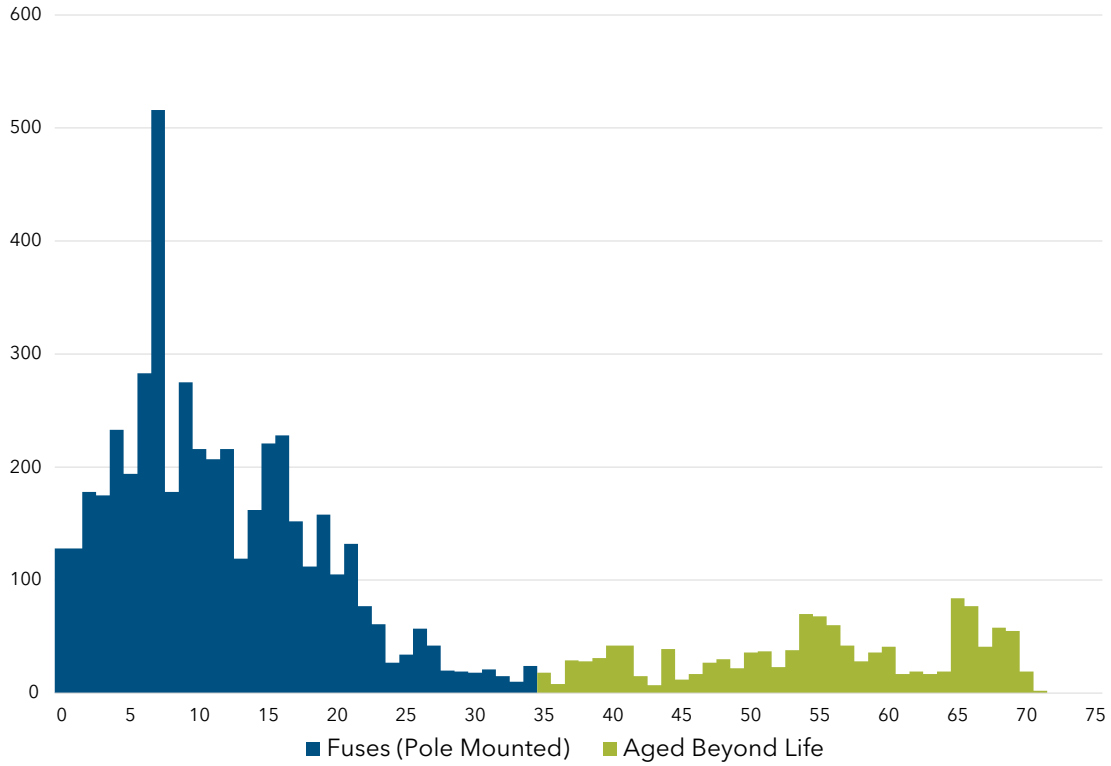
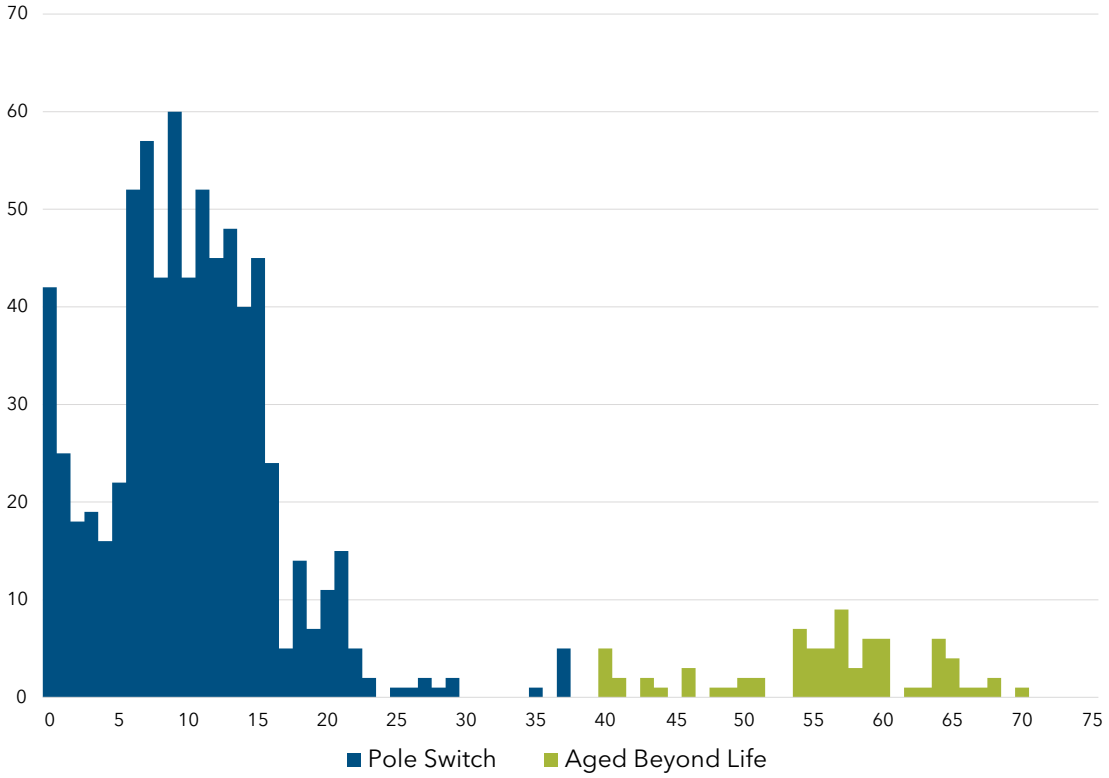
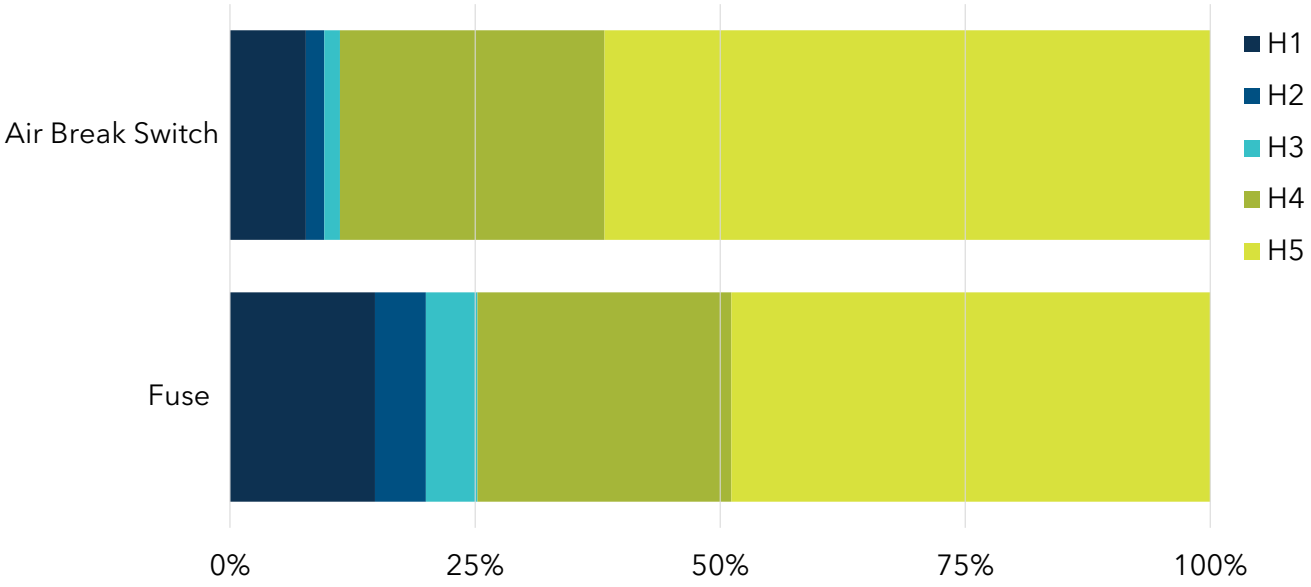


*Figure 90 | Pole switch age profile in years.*




Condition analysis confirms that most pole-mounted devices are performing reliably, supported by their straightforward design. However, older fuse types, particularly glass-tube fuse designs, are more prone to operational failure. Asset health indicators in Figure 91 highlight the contrast, where skew strongly toward H4 and H5, reflecting our current focus on replacing them, while fuses are spread from H2 to H5, with a notable portion in the lower health categories.

*Figure 91 | Pole mounted fuse and switch asset health as of 2022/23.*




Design standards ensure that pole-mounted switches and fuses are installed with bypassing capability, allowing maintenance or replacement to occur without customer outages. Modern designs incorporate stronger insulation and improved mechanical durability, extending life and reducing operational risk.

Maintenance is integrated into the wider overhead line inspection programme. Activities include

lubrication of moving parts, visual checks for corrosion, and targeted replacement of outdated fuse types.

Renewals are largely opportunistic, coinciding with pole replacements or refurbishment programmes. Devices supplying only a small number of ICPs are considered low priority, whereas sectionalising devices that influence larger network areas are given higher renewal priority. All disposals comply with environmental standards, with hazardous materials removed and processed through certified channels.

## Circuit breakers, reclosers, and sectionalisers

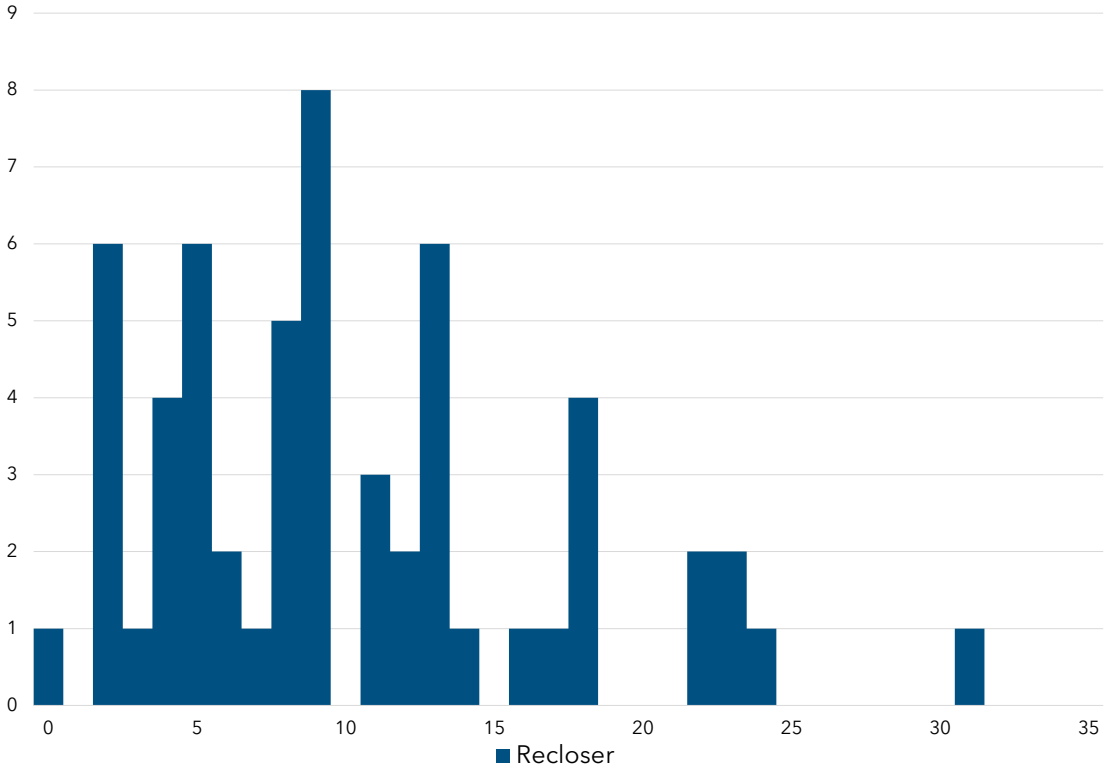
Pole-mounted circuit breakers, reclosers, and sectionalisers provide essential automation and protection on the 11 kV overhead network. Reclosers restores supply following transient faults and isolating persistent faults without operator intervention. Their integration with SCADA systems enables remote switching, delivering faster fault response and greater resilience across the distribution system.

The fleet comprises 74 reclosers, with the breakdown shown in Table 52. This includes 13 vacuum interrupters with oil insulation, 2 with SF6 insulation, 17 with epoxy resin insulation, and 46 with solid polymer insulation. Population data, illustrated in Figure 92, shows a relatively young fleet with most assets less than 15 years old. This reflects recent targeted investment in automation and reliability.

*Table 52 | Recloser types and quantities*

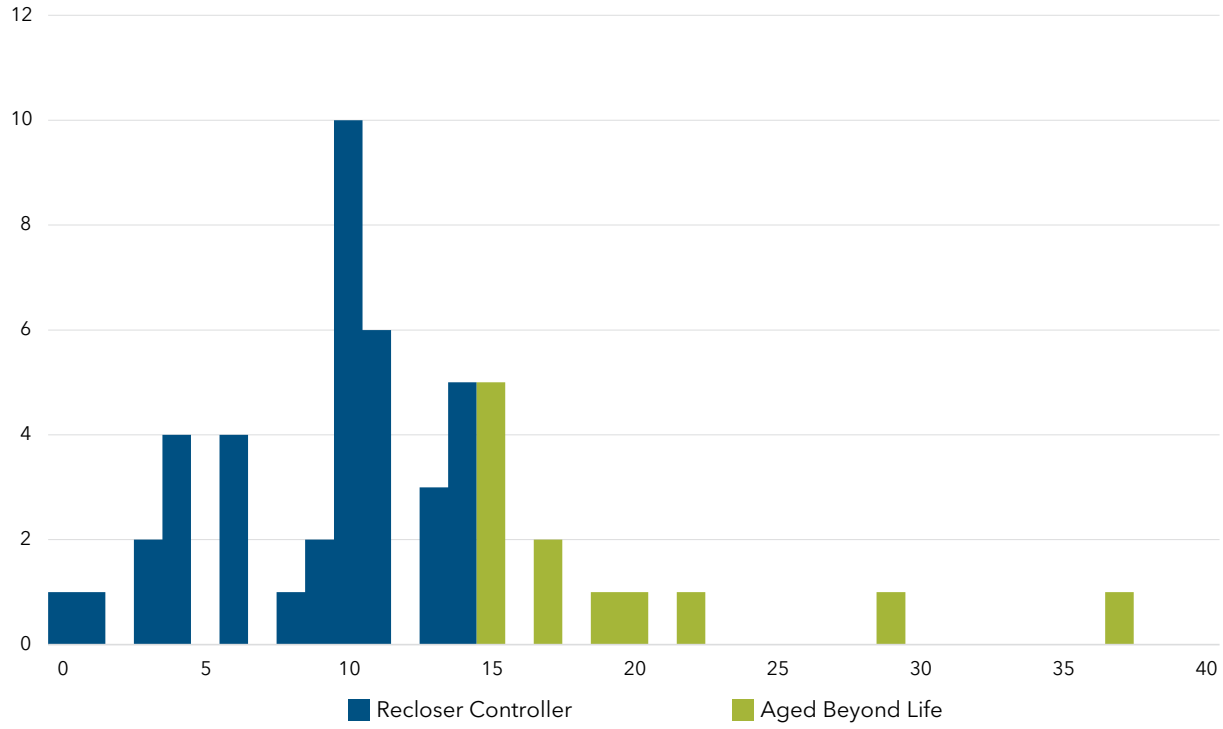
| Type | Number |
|---|---|
| Vacuum interrupter & oil insulation | 13 |
| Vacuum interrupter & $SF_6$ insulation | 2 |
| Vacuum interrupter & epoxy resin insulation | 17 |
| Vacuum interrupter & solid polymer insulation | 46 |

*Figure 92 | Recloser age profile in years*



Recloser controllers are considered separately because, although they operate as part of the same installation, their design life and failure modes differ from the interrupters themselves. Controllers contain electronic components that age faster than the mechanical recloser, which makes them more susceptible to obsolescence, spare part shortages, and compatibility issues. Figure 93 shows the age distribution of recloser controllers, highlighting a small group nearing the limits of their expected service lives and therefore requiring targeted renewal planning to maintain automation capability and reliability.

*Figure 93 | Recloser controller age profile in years*




Condition and health assessments confirm the strong performance of these assets. The majority of reclosers are in H4 and H5, as shown in Figure 94, indicating good to very good condition and low immediate risk of failure. A small share in H3 represents older oil-insulated units, which are being closely monitored. Figure 95 shows the asset health of controllers, which display a broader spread across categories. While many sit in H4 and H5, a notable proportion are in H2 and H3 due to electronic ageing, obsolescence, and limited spare availability. These units are prioritised for renewal to avoid reliability issues.

*Figure 94 | Recloser asset health*

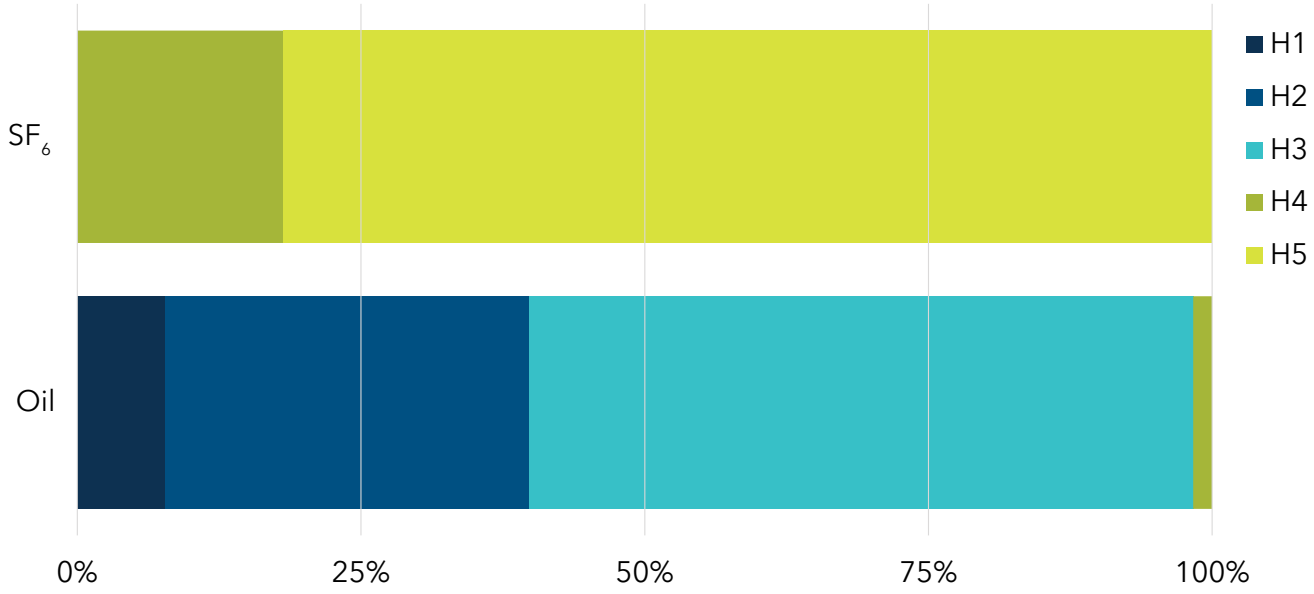
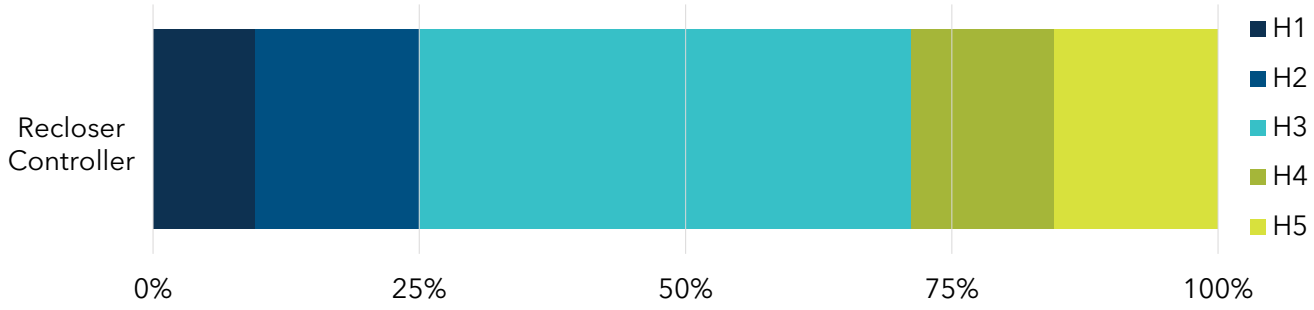



Figure 95 shows the asset health of recloser controllers, which are more widely distributed across health categories than the reclosers themselves. A significant proportion sit in H3, reflecting the impact of electronic ageing and the faster deterioration of components such as capacitors and power supplies. Smaller groups remain in H1 and H2, where obsolescence and the lack of available spares present clear risks. While a share of controllers remain in H4 and H5, the concentration in lower categories confirms the need for targeted renewal to sustain automation capability and avoid reliability issues.

*Figure 95 | Recloser controller asset health*




Design standards ensure every recloser installation incorporates bypass capability through isolating links and an associated air break switch. This arrangement maintains continuity of supply during failures or maintenance. Remote operability is now embedded as a standard feature, with SCADA integration supporting real-time fault management and flexible reconfiguration of the network.

Operation and maintenance practices are tailored to their automation and protection roles. Annual inspections include checks of auxiliary systems such as batteries, chargers, and communications. Thermal imaging is undertaken where load or condition warrants it, helping to detect hotspots before failure. Every four years, reclosers undergo full functional servicing, including bypass and isolator maintenance and testing of the interrupter. Controller batteries are replaced on a five-year cycle, with older controllers upgraded or replaced where obsolescence threatens reliability.

Renewal planning is proactive and focuses on high-risk segments of the fleet. Oil-insulated reclosers and ageing controllers are scheduled for replacement within this planning period.

Investment is directed toward models with stronger noise immunity, enhanced fault detection, and modernised automation features. Environmental obligations are met through controlled disposal processes, with oil drained and processed by certified recyclers and electronic waste managed through approved recovery channels.

## SCADA and communication systems

SCADA and communication systems facilitates the for monitoring, remote control, and secure data acquisition of our distribution network. They ensure continuous visibility, streamline operational decisions, and support efficient fault response. Over time, these systems have evolved through staged investments, resulting in a diverse mix of technologies and standards. In recent years, focused programmes have accelerated standardisation, and this work will continue as we replace ageing components and enhance capability to meet future operational needs.

The SCADA (Supervisory Control and Data Acquisition) portfolio has grown incrementally in response to changing operational requirements, evolving industry standards, and the introduction of automation into field devices. Early systems relied heavily on analogue communications and proprietary protocols, but the network is now transitioning to open standards and digital technologies. Recent investment has prioritised automation, particularly through integration of reclosers, IEDs, and remote access functionality. Growth is also driven by customer expectations of faster outage restoration and improved information, which require both broader coverage and higher system resilience.

The SCADA master station serves as the central control hub. It operates primarily from the Washdyke office with a fully functional hot standby hosted at the North Street Zone Substation. These installations ensure redundancy and continuity of service. The master station is continuously enhanced through new modules that improve alarm handling, event recording, and integration with other enterprise systems. This forward development ensures scalability for anticipated increases in data flow from field devices.

Remote Terminal Units (RTUs) and associated communication devices provide the interface between field equipment and the master station, transmitting telemetry and executing control commands. The fleet now comprises 68 devices across a range of functions, as summarised in Table 53. This includes 14 communication controllers and RTUs (21 percent), 20 communication sets (29 percent), 8 ethernet routers (12 percent), 7 input and output devices (10 percent), and 19 protection and control boxes (28 percent).

*Table 53 | SCADA RTU population by type on 31 March 2022/23*

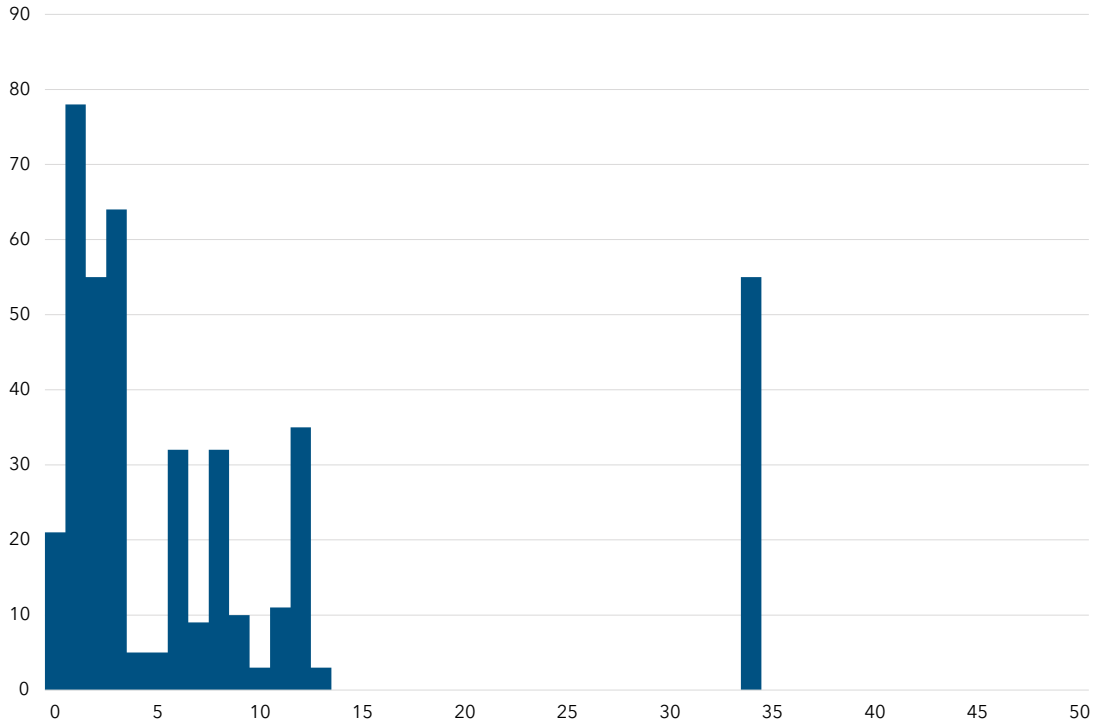
| Type | Devices | % of total |
|---|---|---|
| Communication Controller and RTU | 14 | 21% |
| Communication Set | 20 | 29% |
| Ethernet Router | 8 | 12% |
| Input / Output Devices | 7 | 10% |
| Protection and Control Box | 19 | 28% |
| **TOTAL** | **68** | **100%** |

This broader mix reflects the evolution of the fleet from simple RTUs to a more diverse set of communication and control devices that collectively support modern SCADA operations. Standardisation on the "Distributed Network Protocol version 3" (DNP3) communications protocol remains central to this programme, ensuring consistent integration with Intelligent Electronic Devices (IEDs). Modern units provide remote access capabilities, enabling engineers

to retrieve and analyse data without attending site, which reduces outage durations and improves operational efficiency. In contrast, older and less flexible devices are limited by proprietary systems or hardwired connections, making them more challenging and costly to maintain over time.

The population and age statistics, shown in Figure 96 highlight the progress already made in modernising our SCADA and communications fleet. Considerable renewal work has already been completed, particularly in upgrading RTUs. Today, only two legacy RTUs remain, representing a small share of the fleet and scheduled for replacement within this planning period. Once this programme is finalised, all RTUs will be standardised on the DNP3 protocol, which enables direct integration with IEDs and strengthens system resilience.

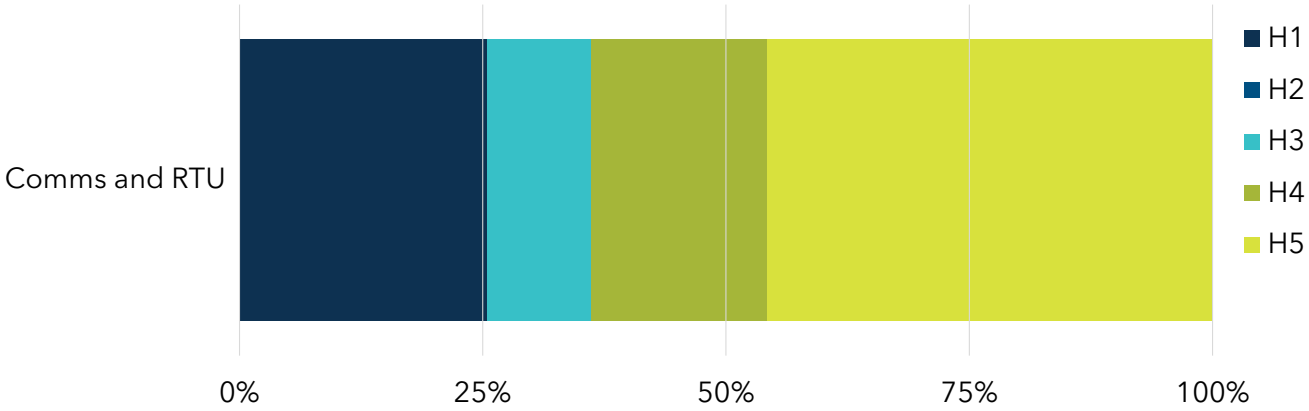
*Figure 96 | Zone substation SCADA and communications device age profile*




The communications network underpins SCADA as well as protection, metering, and telemetry systems. It is a layered system that combines fibre optics, microwave links, UHF and VHF radio, and Ethernet/IP-based circuits. Supporting infrastructure such as masts, cabinets, and repeater stations extend coverage across the network. Much of the system is Alpine-owned, but some elements are leased or shared with third parties. Historically analogue, the network is steadily transitioning to digital technology, which offers higher capacity, greater resilience, and advanced features such as intelligent fault restoration. This digital migration also strengthens cyber security, an increasing priority as more devices connect to the network.

The latest asset health data (Figure 97) shows that communications and RTU assets are spread widely across all asset health categories. A significant share sits in H1 and H2, indicating units that are already at or near end of life, with associated risks of failure, obsolescence, and lack of spare parts. A portion of the fleet sits in H3, reflecting mid-life condition where increasing maintenance effort is required to sustain reliability. The remainder of the fleet is healthier, with assets in H4 and H5 performing well. This spread highlights the dual challenge of replacing high-risk legacy devices while ensuring that mid-life units are closely monitored to prevent emerging vulnerabilities such as network blind spots, cyber risks, and delayed fault responses.

*Figure 97 | RTU asset health as of 2022/23.*




Beyond physical ageing, two broader risks dominate the SCADA and communications portfolio: the potential loss of visibility and control, which heightens the likelihood of switching errors and prolonged outages, and the growing threat of cyber security breaches, where unauthorised access could compromise safety, reliability, and financial stability. These risks are being addressed through targeted replacement of legacy assets, standardisation on modern communication protocols, and the continuous strengthening of cyber security measures.

Design philosophy for SCADA and communications systems centres on resilience, scalability, security and safety. Numerical relays and IEDs now generate vast amounts of operational data, requiring systems with higher capacity and smarter data polling. Modern RTUs are designed to provide remote access, supporting faster fault analysis. Communications upgrades focus on replacing analogue systems with digital alternatives, improving speed and enabling features such as automatic fault restoration. Supporting infrastructure, such as repeater sites and control buildings, is also modernised to align with these capabilities.

Maintenance is targeted at preserving reliability. Communications equipment and RTUs are subject to quarterly inspections, which test asset functionality, check the condition of buildings and ancillary systems, and identify early signs of deterioration. The SCADA master station undergoes patching as required to maintain cyber security and operational stability. Ongoing monitoring of RTUs also identifies anomalies, supporting a condition-based maintenance approach.

Renewals are driven primarily by obsolescence. The three remaining legacy RTUs are scheduled for replacement in this AMP planning period, ensuring all field sites operate on DNP3. Ageing microwave links and routers will also be progressively replaced with modern, secure alternatives. Condition-based renewals are applied to supporting infrastructure such as masts and repeater buildings. In all cases, disposal follows regulatory standards, with hazardous electronic components processed through certified recyclers.

## Voice communication

Voice communication remains vital for safe daily operations. The current network comprises VHF radios supported by hilltop repeater sites linked to the Control Centre by UHF trunk radio. While effective the existing analogue platform is limited in terms of channel capacity data integration and encryption. A staged upgrade to digital mobile radio (DMR) is underway improving clarity coverage and security. The digital system also integrates better with operational control ensuring that field teams remain connected during both routine operations and emergencies.

# 8. Supporting our network

## 8.1. Investment summary

Figure 98 below provides an overview of the material projects proposed under the Support and Transformation investment theme for the next 2 years. Each project is directly aligned with Alpine Energy's Asset Management Plan (AMP) priority of laying the foundations for a digital, flexible future, detailing their timing, budget, and expected outcomes to support the strategic objectives outlined in this section.

*Figure 98 | Summary of material Support and Transformation investment projects*

| Project Name | Digital principle | Timing | Budget | | Outcomes |
|---|---|---|---|---|---|
| | | | Capex | Opex | |
| **Everyday AI** | AI Driven | FY27-28 | | $150k | Reduce time to complete everyday tasks by leveraging Generative AI for automation, content generation, and decision support, resulting in measurable productivity improvements and democratised access to advanced AI tools across the enterprise. |
| **Cyber Security Programme** | Cyber Security | Ongoing | | $700k per annum | A risk-based response to cyber security threats and challenges, that is cost-effective and flexible to adjust to evolving threat landscapes and technologies. We are compliance ready for incoming legislation for critical infrastructure services. |
| **Data Strategy implementation** | Data and Information Ecosystem | FY27-28 | | $150k | Enterprise data platform fully embedded as a strategic enabler, providing secure, governed, and democratised access to data, analytics, and predictive models for improved asset performance and risk management. |
| **Customer Shift** | Digital Customer Experience | FY27 | | $300k | Faster, consolidated and more accurate communications to our customers regarding outages and vegetation management needs. Customer connection requests are managed with transparency and consistency with industry standards. |

| Project Name | Digital principle | Timing | Budget | | Outcomes |
|---|---|---|---|---|---|
| | | | Capex | Opex | |
| **Digital Skills** | Digital Skills & Learning | Ongoing | | $50k | Our people have the skills they need to perform their roles and the digital fluency to adopt new technologies such as AI and integrate the productivity efficiencies they bring into their everyday. |
| **Future-ready Network Operations** | Future technology led | FY27-28 | | $210k | Mitigate risk of manual 'as operated' network diagrams through digital 'mimics', improving safety for our field workers and improving resilience in the event of emergencies. Upgrading and expanding SCADA functionality to support mobile access, electronic switching preparation and integration with core systems. |
| **Future-ready Network Planning** | Future technology led | FY27-28 | | $130k | Uplift digital tooling for our future networks team to provide advanced modelling functions, improving the accuracy and confidence of network forecasting and investment. |
| **Enterprise Content Management** | Modern Architecture | FY27-28 | | $100k | Improving the security of our data and information, making it available and accessible when needed, including to integrated systems and artificial intelligence tools. Leveraging value from existing licensing. |
| **Digital operations and infrastructure upgrades** | Modern Architecture | FY27 | $250k | $159k | Critical operational technology operates on secure, modern platforms, reducing security and availability risks while lowering support costs and improving user experience. Reliable, streamlined communication ensures safety messages are clear and secure, enabling frontline focus on critical tasks, while telephony and connectivity risks are minimised in line with a digital-first approach. |
| **ERP/EAM implementation & Operating Model transformation** | Modern Architecture | FY27-28 | | $9m | D365 F&O will be the digital foundation for our future operating model, driving efficiency through our value chain and enabling decisions about what we do and how we do it in the future. |
| **Integration strategy implementation** | Modern Architecture | FY27-28 | | $400k | Ensure the integrity of our data by having a single source of the truth and ensuring consistency of data where it is used. Making data available where it is needed, reducing manual processes. |
| **Payroll Consolidation** | Modern Architecture | FY27-28 | | $50k | Consolidated payroll platform that ensures compliance to legislation and provides a simple, accessible way for our people to interact with time, attendance and job allocation information. |

## 8.2. Our digital strategy

At Alpine, **'digital' means applying the culture, practices, processes, data and technologies of the modern era to drive progress towards energy affordability, security and sustainability through effective asset and network management.** Our Digital Strategy aligns with our driving forces and the assumptions of how these factors are expected to materialise, specifically technological transformation and digitalisation.

Through our Digital Strategy, we will look to expand the bounds of what is possible by becoming a Digital Leader and driving a Digital First collaborative digitisation of the whole business and play our role supporting the whole energy system across four themes:

1. We will facilitate industry technological expertise by staying abreast of technologies, industry trends and sharing digital best practices.
2. We will maximise the value of data and technology by leveraging it to inform decisions and enhance operational efficiencies.
3. We will contribute to the industry's digital direction through collaborating on the development of data standards and accessible, reliable and interoperable data.
4. We will explore innovation opportunities by collaborating and partnering with all our existing and emerging partners.

**Digital Leader**

Embeds digital in every aspect of our organisation and operates with continual digital reinvention, participating in digital collaboration within the industry

**Digital First**

Integrates digital into every aspect of our organisation, thinks beyond Alpine and for the industry, thinks digital beyond existing technology.

Our role in the energy system means data and technology can provide value for our customers and community by driving value, enabling our business to be responsive and efficient both in how we provide solutions and engage with our customers and how we collaborate within the wider energy sector.

*Figure 99 | Data and technology in the energy system*

| Value driven | Responsive and efficient | A trusted advisor | Engaged with customers |
|---|---|---|---|
| We aim to deliver digital tools and services that maximise value at the lowest cost | We prioritise proactive and effective solutions that meet internal and external needs while also being adaptable to future requirements | We provide thought leadership and support a transparent and collaborative energy sector through open and discoverable data | We seek to continuously gather customer feedback and to use it to improve digital interactions |

Our digital strategy will deliver tangible and significant value by employing effective and forward-looking digital solutions, fostering collaboration, and aligning to the industry's digital efforts to maximise value at the lowest cost.

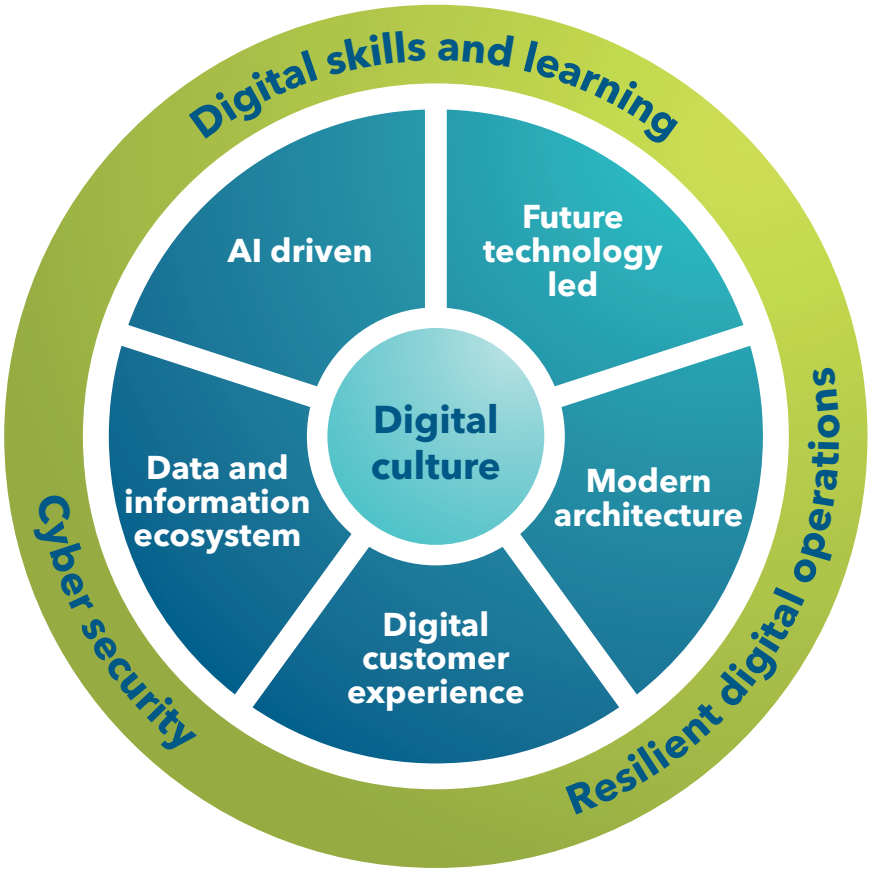
As our business and the industry evolves at a pace faster than ever before, our technology and data must be flexible and agile enough to live on a sliding spectrum, adjusting to business context, energy system, regulatory and market developments. Our Digital Strategy Principles guide our investment and prioritisation of technology and data decisions through enuring digital and data is at the core of our culture, delivering through strategic accelerators with our enablers guiding everything we do.

*Figure 100 | Digital Strategy Principles*

**The Strategic Centre:**
Digital culture is at the core of our Digital Leader ambition. To effectively operationalise our strategy, we need to align our culture on digital and data tools.

**The Accelerators:**
Branching off the strategic centre are our Accelerators which facilitate how we deliver the strategy.

**The Enablers:**
Surrounding our Accelerators, these elements must be considered in all decisions regarding digital, data and technology processes.




These principles work together to bring improvements and efficiency to digital interactions for our people, customers and stakeholders. These components aim to increase automation and digital assistance so our people can focus on high value, complex and strategic tasks. They also aim to support industry transparency and availability of data at a crucial time of transition towards open network principles for distribution system operator capabilities.

## 8.3. Our strategy in action

In our 2023-2025 Asset Management Plans, we set out our core investment plans to modernise our architecture and lay the foundations for:

- Our Target Architecture blueprint towards Modern Architecture to address the risks of legacy systems, reduce long-term costs, support the efficient and effective delivery of our core services and facilitate efficient customer service delivery.
- Definition of a revised Operating Model which will move us towards a Digital Culture by transforming core value chain processes and responsibilities and eliminating manual effort and rework, improving the quality of our asset data to better inform investment analysis, and streamlining end-to-end processes.
- Our Cyber Security Programme to ensure a continuous focus on managing cyber security risk in an ever-changing landscape by partnering with industry peers and technology providers.
- Investing in our Disaster Recovery capabilities to provide the backbone of Resilient Digital Operations, ensuring we can operate when our community needs us the most.

## Key Progress so far

In our 2023 AMP we outlined our digital investment programme, which matured through 2024-2025 into our Target Architecture roadmap. In our 2025 AMP we signalled changes to our digital investment programme, consolidating our ERP & EAM programmes into a single, integrated solution aligned with operating model transformation to drive an efficient core value chain. Since 2023 we have completed initiatives focused on:

- mitigating technology risk
- improving core compliance and works delivery processes
- creating transparent customer engagement processes
- reducing cyber security risk and improving digital resilience
- undertaking innovation initiatives to prove value within our engineering and asset management practices

Building on these priorities, we have delivered a series of initiatives that modernise our architecture, strengthen cyber resilience, embed digital skills, and leverage advanced technologies to improve customer experience and asset performance. These achievements reflect our commitment to creating a secure, data-driven, and digitally fluent organisation. The following summary outlines the key progress made under each strategic principle and the value these initiatives have delivered.

*Table 54 | Progress against our strategic principles*

| Strategic principle | Progress | Outcomes |
|---|---|---|
| **Modern Architecture** | We selected and approved our ERP/EAM system (Microsoft D365 F&O) and gained Board approval for Phase 1. Several systems were implemented, including ICP Billing & Lifecycle Management, Network Programme & Project Management, automated Job Pack Workflow, a cloud-hosted geospatial information system, a Field Mobility solution, an Outage Management module, and upgraded core infrastructure. | These initiatives have provided detailed plans and investment for future phases, streamlined ICP management and billing, increased transparency and control over project delivery, reduced manual handling, strengthened spatial asset visibility, enabled real-time field data capture, automated regulatory reporting, and modernised our systems for scalability and resilience. |
| **Digital Skills & Learning** | We commenced the transition towards a single unified operating model, initiating the digital amalgamation of NETCon onto Alpine's core systems underway and ensuring staff are trained and familiar with the new platforms. | This is unifying our digital platforms, enabling better collaboration and delivering a consistent digital experience across the organisation. |
| **Digital Culture** | Automated workflows were created for routine, low-complexity processes, replacing manual steps with digital solutions. | As a result, manual processes have been digitised, reducing the time and effort required for internal transactions. |
| **Future Technology Led** | We leveraged LV and Smart Meter data for network planning, piloted LiDAR and drone asset capture for overhead lines and vegetation assessment and implemented digital twin capabilities for overhead line design. | These actions have improved forecasting and modelling accuracy, reduced inspection times, enabled faster identification of asset risks, increased asset resilience, and reduced the time and effort needed for design processes. |

| Strategic principle | Progress | Outcomes |
|---|---|---|
| **Digital Customer Experience** | A Customer Relationship Management system was implemented, along with new processes for handling inbound customer enquiries and connection requests. | Service delivery has been enhanced through centralised, real-time customer data access, resulting in faster response times to customer enquiries. |
| **Data & Information Ecosystem** | We implemented modern Data & Analytics platforms, defined core data schemas, and developed risk-based models for inspection and maintenance prioritisation, while identifying lifeline asset dependencies. | This has enabled data-driven decision-making, improved modelling and forecasting, reduced outage and safety incident likelihood, and strengthened our ability to coordinate emergency responses. |
| **Cyber security** | We onboarded into a Security Operations Centre, undertook network security remediation projects, conducted annual penetration testing, improved IT controls, and enhanced digital identity protection using zero trust and least privilege principles. | These measures have improved our ability to detect and respond to threats, closed critical vulnerabilities, strengthened governance and compliance, reduced costs, and improved controls to prevent unauthorised access. |
| **Resilient Digital Operations** | Disaster recovery technology and plans were implemented and tested, including network redundancy. | We now have assurance that our systems can continue operating during major incidents, enabling us to support our community effectively. |

### What's next – our Horizon 1 business plan

Alpine's Digital First goal is to embed technology and data into everything we do, improving efficiency, empowering people, and enhancing customer outcomes. The focus for FY26–28 is completing our Target Architecture roadmap and building core capabilities. Our 2025 Horizon 1 Business Plan lays out the remaining digital investment in technological transformation and digitalisation to enable effective asset and network management. We continue to build on our digital strategic principles, laying the foundations for future operating model and industry directions.

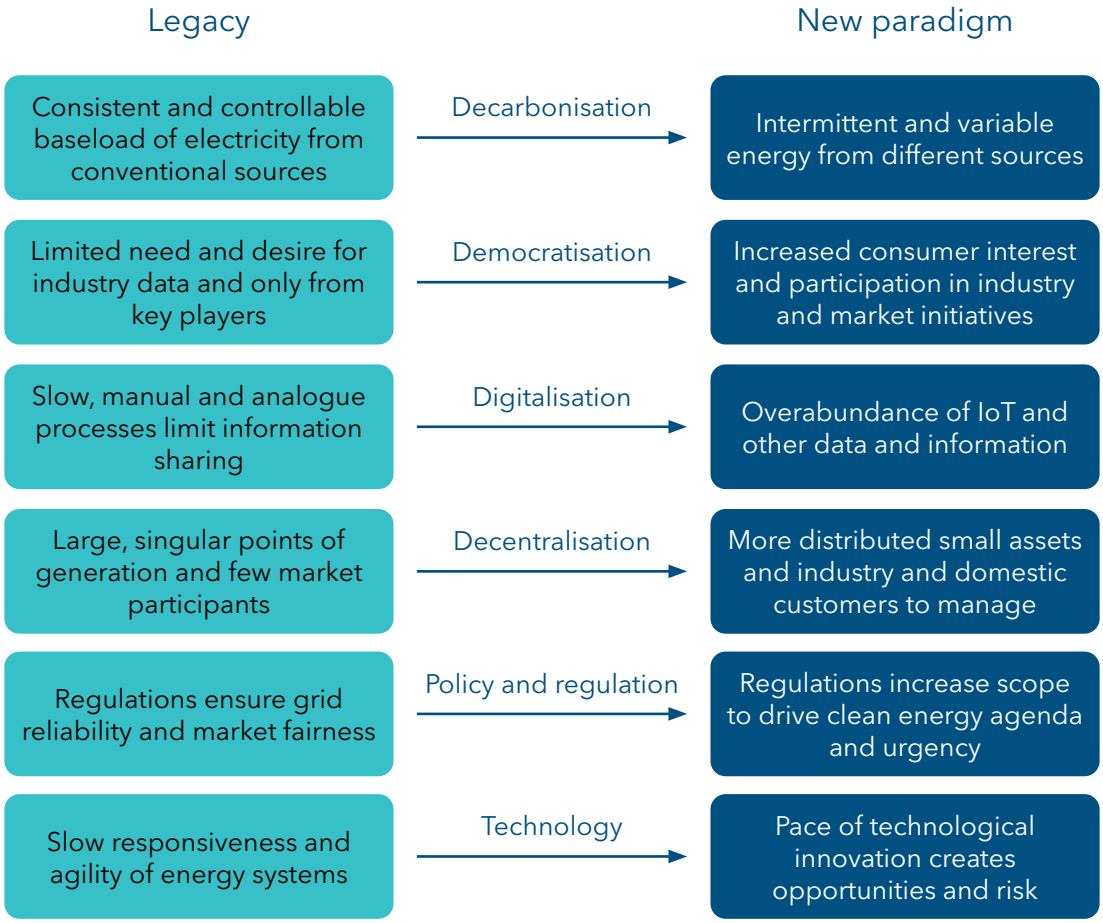
## 8.4. Horizon 1 investments

Lines companies are imagining a future in Aotearoa with:

- Close to 100% renewable generation
- Mass uptake of flexible distributed energy resources (DER)
- DER used for non-wires alternative and system balancing
- Electric vehicles and hot water responding to price signals
- Risk of 'herded' load discharge – refers to a situation where many electrical loads are released, restored, or discharged at the same time, causing a sudden and concentrated change in system load.

Beyond decarbonisation goals, the energy industry is going through fundamental changes, this new paradigm will need to be embraced to ensure change happens at the pace required to support industry and our business goals. Digitisation, as well as open data, will underpin this transition through better management and monitoring of the system and improved sharing of large quantities of high-quality data and analytics that this enables. This is key to navigating increasing complexity at the lowest possible cost to customers.

*Figure 101 | Fundamental changes in the energy industry*




The energy transition will evolve how frequently and closely we work with the wider industry on a wider range of topics. These relationships are key to developing intertwined processes, innovation collaborations and open data to help keep industry costs low. To better facilitate these endeavours, our industry needs to align on foundational digital and data directions. We will target initiatives within 3 core strategic Accelerators (AI Drive, Future Technology Led and Data & Information Ecosystem), underpinned by our Enablers, within this AMP period to both prepare for and enable Horizon 2 and 3 strategic drivers, including industry collaboration and data interoperability.

## Summary of material projects

*Table 55 | Material projects*

| Project Name | Project description | Digital Principle | Timing | Budget | | Outcomes |
|---|---|---|---|---|---|---|
| | | | | Capex | Opex | |
| Game-changing' AI | Seek out 'game-changing' industry AI use-cases to shift the dial on our asset management practices, moving from manual deterministic planning to probabilistic modelling and data-driven automated risk and investment assessments. Collaborating with industry to train AI models with rich data sets, enhancing accuracy and performance. | AI Driven | FY28-32 | | $325k | Greater accuracy, confidence and agility in our asset investment and works decisions, being able to quickly understand and impact assess changes in strategic drivers, risk and industry change. Joint AI models and projects, distributing benefit and outcomes across the industry. |
| DSM readiness | Prepare for distribution system management by assessing the readiness of our SCADA telemetry, field devices, data flows and communication infrastructure to meet system capabilities for real-time monitoring, outage detection, fault location, isolation and service restoration and voltage optimisation | Future Technology Led | FY27-30 | $1m | | Targeted roadmap of improvements enabling us to be ready and able to integrate into a distribution management system for improved and efficient network operations, reducing cost and improving customer experience. |
| DSO readiness | Prepare for industry wide interoperability requirements for a DSO future by ensuring we have defined and standardised asset data models with integrity and availability built in. | Data & Information Ecosystem | FY28-33 | $300k | | Lead and contribute to industry standards for asset data model and hierarchies, removing technical barriers for seamless operations between industry parties. |

## Property and fleet

Our property investments focus on creating a safer and more efficient environment for day to day operations. The planned redevelopment of our yard will provide a functional, secure, and future ready site that supports operational efficiency, improves material handling, and strengthens staff wellbeing. This upgrade ensures that the facilities underpinning our field and delivery teams remain aligned with the growing scale and complexity of work across the AMP period.

Our fleet renewal programme complements this by ensuring our vehicles remain reliable, efficient, and suited to the workload ahead. A fit for purpose fleet is essential for maintaining productivity, meeting response expectations, and supporting operations across a wide geographic area. The planned investment provides for a structured replacement of ageing vehicles and the introduction of units that better support future field practices. Together, these property and fleet projects strengthen the operational foundation needed to deliver our AMP safely, efficiently, and sustainably.

### Material property and fleet projects

*Table 56 | Material property and fleet projects*

| Project Name | Project description | Cost ($'000) | Timing |
|---|---|---|---|
| Yard development | Redevelopment of the operational yard to create a safe, functional and future ready site that supports efficient material handling, resilient operations and staff wellbeing. | 3500 | FY27–FY28 |
| Fleet replacement | Structured renewal of the vehicle fleet to ensure reliable, efficient and fit for purpose transport for field operations across the network. | 4,890 | FY27–FY28 |

## Asset information support

### Digital Services

The Digital Services team is responsible for designing, integrating, and supporting our enterprise technology platforms, including ERP, GIS, CRM, Productivity and industry specific applications. They ensure these systems are secure, scalable, and aligned with business needs, while leading the company's cybersecurity strategy and managing digital vendors and IT support. By embedding digital tools and automation across the business, Digital Services drive operational efficiency, empower staff, and lay the foundation for a modern, unified operating model, directly supporting our "Digital First" strategy and transformation goals.

### Network Intelligence & GIS

Network Intelligence & GIS lead the development and execution of our data strategy, maintaining high-quality network asset data and robust data governance across the value chain. This function provides advanced analytics, data visualisation, and geospatial services to support strategic decision-making, asset management, and operational planning. By democratising access to trusted data and insights, Network Intelligence & GIS enable evidence-based decisions, optimise asset performance, and help build a data-driven culture that maximises the value of its assets and supports future growth.

### Innovation

The Innovation function drives the adoption of emerging technologies, automation, and data science initiatives. This includes piloting new digital tools, AI models, and innovative solutions to improve efficiency, customer outcomes, and network reliability. Innovation partners with business units to explore use cases in predictive maintenance, workflow automation, and customer insights, while ensuring ethical integration of AI and fostering industry collaboration. By championing a culture of experimentation and continuous improvement, Innovation accelerates our digital transformation and positions the company as a leader in delivering sustainable, customer-centric energy solutions.

# 9. Risk and resilience

Resilience is central to our ability to deliver safe, reliable, and affordable electricity services in a changing and uncertain environment. It supports our capacity to meet customer expectations, comply with regulatory requirements, operate efficiently, enable regional growth, and react appropriately to unforeseen events. Our asset management approach recognises resilience as a critical outcome shaped by effective risk management applied across all operational activities.

The seven operational scenarios that guide our planning are Compliance, Customer, Efficiency, Growth, Operation, Resilience, and Unforeseen. These reflect the range of risks we must anticipate and manage. These include environmental risks such as natural hazards and climate change, operational risks linked to asset performance and service continuity, customer risks associated with reliability expectations, and emerging risks such as cyber threats and supply chain disruption.

Managing these risks requires a coordinated approach that brings together risk management, asset life cycle planning, business continuity, emergency preparedness, and cyber resilience. Our focus is on identifying risks early, reducing vulnerabilities, and enhancing our ability to sustain operations under adverse conditions.

Risk and resilience are embedded in our governance, decision making, and operational practices. Our policies, frameworks, and management systems are designed to ensure that resilience is considered in both strategic planning and daily operations. This chapter explains how we manage risk and build resilience across our operations. It describes our governance arrangements, risk assessment processes, investment prioritisation, emergency management, business continuity, cyber resilience, and critical infrastructure strategies. Each section reflects our commitment to strengthening resilience within the seven operational scenarios and ensuring our network remains capable, adaptable, and responsive in a complex and evolving risk environment.

## 9.1. Risk environment and local context

We operate in a region exposed to a wide range of risks that influence our ability to provide a safe, reliable, and affordable electricity service. Our network spans urban, rural, and remote areas, each presenting distinct environmental, operational, and community considerations. These risks impact the likelihood and severity of events and key elements of our risk environment include:

- **Natural hazards:** We face exposure to seismic events, flooding, extreme weather, and wind storms. These events can cause widespread damage to our network assets and disrupt service delivery. Climate change is expected to increase the frequency and severity of extreme weather, placing additional strain on both our physical infrastructure and our operational capacity. Managing these risks is critical to maintaining resilience and protecting community welfare.
- **Infrastructure dependencies and supply chain risks:** Our reliance on national grid connections, telecommunications, fuel supply, and transport networks creates exposure to external disruptions. Interruptions to these shared services can affect both planned operations and emergency responses. We work closely with suppliers, service providers, and regional agencies to manage these interdependent risks.

- **Customer demand and community expectations:** Growth in population and changing patterns of electricity use influence the capacity and reliability of our network. Customers expect rapid restoration of service, reliable supply, and price certainty. We monitor asset condition, manage capacity constraints, and review maintenance practices to balance service delivery with operational efficiency.
- **Emerging risks and evolving threats:** Cyber security risks, supply chain vulnerabilities, and geopolitical uncertainties add complexity to our risk environment. These factors have the potential to disrupt operations, compromise data integrity, and erode customer confidence. We recognise that resilience relies not only on infrastructure but also on strong organisational capability, effective risk governance, and active community engagement.

We apply structured scenario analysis, risk assessments, and operational intelligence to inform our planning and decision making. By combining local knowledge, industry practice, and regulatory guidance, we enhance our ability to anticipate risks, respond effectively, and adapt to changing conditions within our operating environment.

### 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% chance that it will be a magnitude 8+ event which would likely have a significant impact on our infrastructure.
- South Canterbury endures cold winters and regular weather extremes. Two years of data show winter and spring winds in inland Canterbury could increase by 15% to 25% by 2090 under high emissions scenarios.
- Climate projections for Canterbury show increased rainfall intensity, expecting 15% to 40% more rainfall in winter by 2090, and rising flood risk. NIWA estimates regional flood exposure at about $40 billion as of 2016. Severe weather in May 2025 triggered regional states of emergency and heavy rain of over one hundred millimetres in twenty four hours.
- 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.

## 9.2. Risk management governance and policy

Our approach to risk management is built on governance, structured decision making, and alignment with recognised standards. We apply the principles of ISO 31000 across all operational areas, ensuring that risks are identified, evaluated, and addressed in a consistent and deliberate manner.

Risk management is fully integrated into our planning, investment, and operational processes. It is treated as a shared responsibility across the organisation, with every team contributing to the identification and management of risks relevant to their activities. Accountability for risk is embedded within our governance model, with defined roles at every level:

- **Board oversight:** The Board has ultimate responsibility for risk management. It sets our risk appetite and monitors performance against it through regular reporting.
- **Committee support:** The Audit and Risk Committee supports the Board by reviewing key risks, monitoring the effectiveness of internal controls, and providing structured oversight of our risk approach.

- **Leadership implementation:** The Executive Leadership Team implements the risk management framework, sets organisational risk priorities, and ensures decisions are informed by risk assessments.
- **Team delivery:** Business units and operational teams apply risk management in daily activities, identifying emerging risks and confirming that appropriate controls are maintained.

Our Delegation of Authority framework ensures that decisions involving significant risk receive appropriate review and sign-off. This helps maintain governance discipline, supports informed decision making, and reinforces a culture of accountability.

We maintain a clear and structured risk management policy that outlines our intent to manage risk effectively, enhance organisational value, and strengthen operational resilience. This policy supports innovation, directs investment to where it is most needed, and ensures that risk is considered as part of every important decision we make.

## Risk management framework and processes

Our risk management framework provides a consistent and practical approach for managing uncertainty across all parts of the business. It is aimed to be aligned with ISO 31000:2018 and supports both strategic and operational decision making.

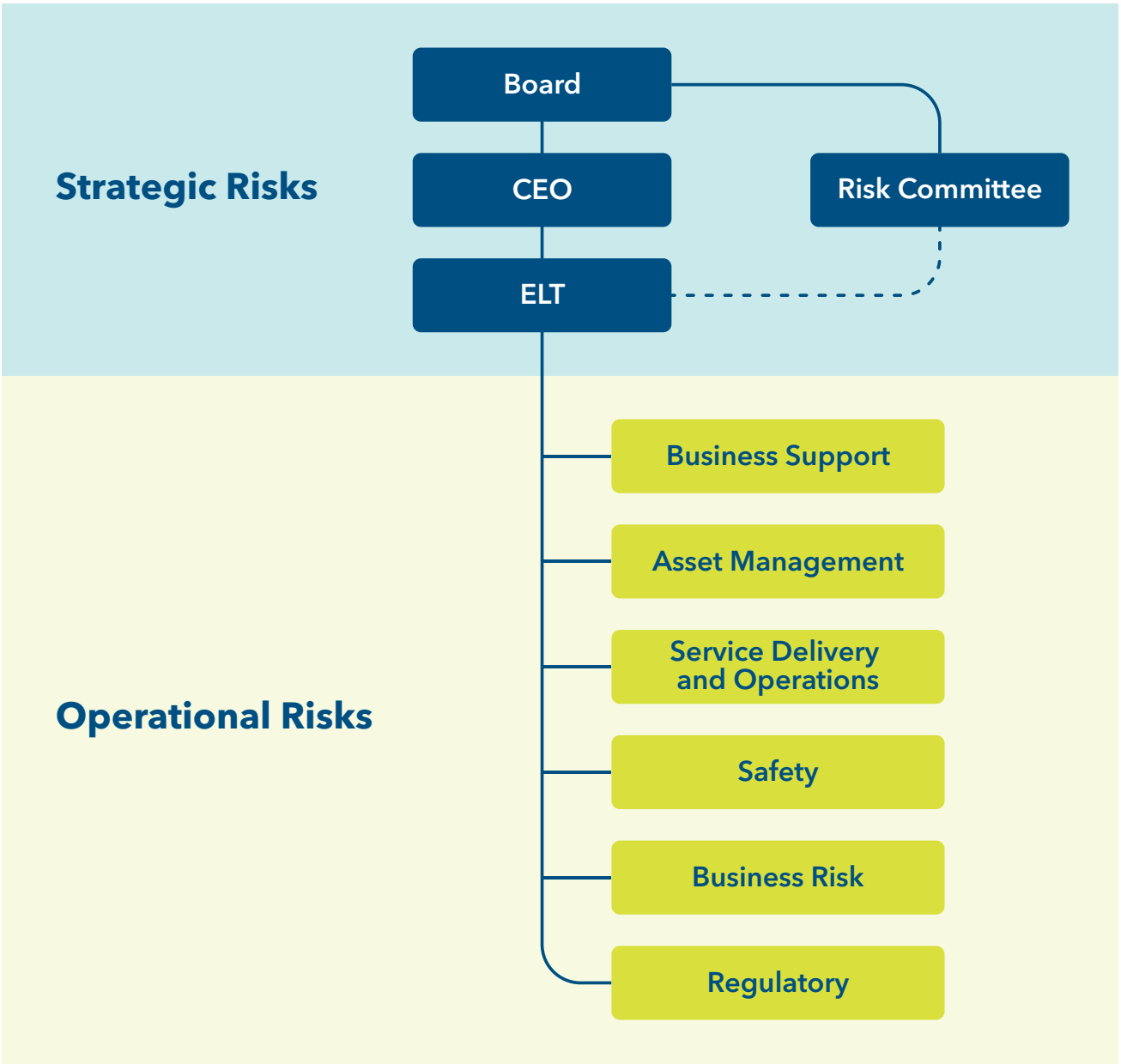
The framework sets out a structured process to help us understand risks early, respond appropriately, and make informed choices. It is used to guide maintenance strategies, prioritise investment, and adapt to changing conditions.

The key steps in our risk management process are:

- **Identify risks:** We identify risks that could affect objectives, including strategic, operational, and project risks. This draws on asset data, industry insights, regulatory changes, and feedback from our community.
- **Assess impacts:** Risks are assessed by their likelihood and potential consequences. We use performance records, condition data, and scenario modelling to understand where risks may emerge.
- **Select treatments:** We evaluate the available options and select the most suitable treatment for each risk. This may involve reducing the risk, transferring it, accepting it, or avoiding it altogether. Each decision is based on cost benefit analysis, our risk appetite, and how the treatment aligns with our operational scenarios.
- **Monitor and review:** We monitor risks and check that treatments remain effective. Regular reviews help us spot changes in risk exposure and adjust our response.
- **Engage stakeholders:** Communication is part of every step. We keep stakeholders informed, promote transparency, and support shared accountability.

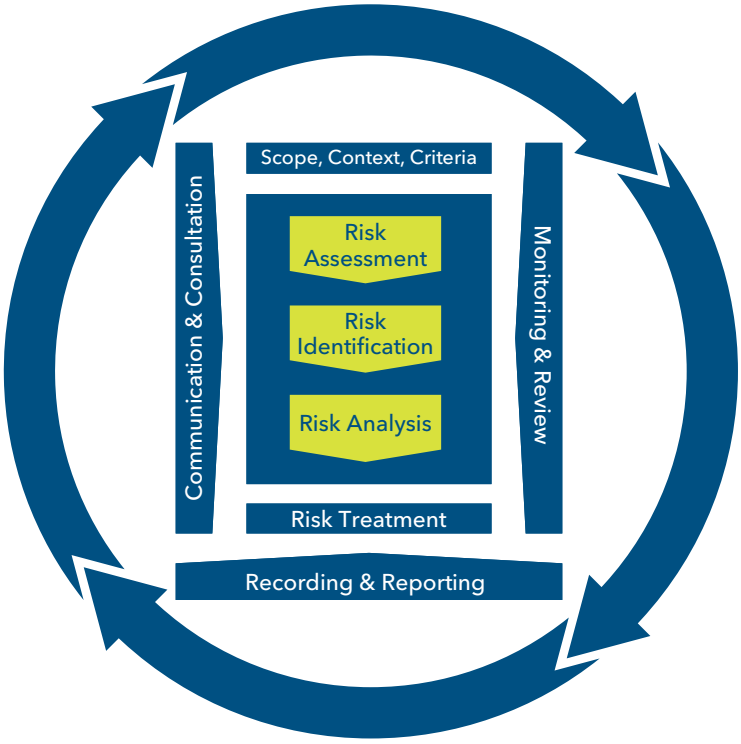
This risk process is linked directly to our asset lifecycle planning, works programme development, and investment decisions. It helps ensure that our plans reflect real-world risks, that resources are directed to where they are most needed, and that our network remains resilient and responsive.

*Figure 102 | Risk responsibilities*




We will improve our risk management process as represented in ISO31000 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 103 | Risk management process in accordance with ISO31000*




## Works Programme Committee and Risk-based investment decisions

Investment decisions are guided by a structured governance process that ensures alignment with strategic objectives, customer needs, and key risk considerations. At the centre of this process is the Works Programme Committee, which reviews, assesses, and prioritises proposed projects for inclusion in our Works Programme.

The Committee applies clear risk-based criteria to support investment decisions that balance safety, performance, cost, and community expectations. Each proposal is assessed for its contribution to network resilience and alignment with our operational scenarios. Key investment considerations include:

- **Health and safety:** We prioritise projects that address critical safety risks affecting the public, our customers, and our workforce. These investments reinforce our commitment to safe service delivery.
- **Environmental impact:** Environmental risks are assessed alongside potential effects on land, waterways, and sensitive ecosystems.
- **Regulatory compliance:** All projects are checked against legal and regulatory obligations. This includes compliance with electricity sector standards, environmental regulations, and workplace safety requirements.
- **Service performance:** We invest in projects that improve reliability, reduce the frequency and duration of outages, and enhance service quality.
- **Capacity and growth:** Projects are assessed for their ability to meet future demand, support new connections, and improve network flexibility. This ensures that investments enable efficient and timely growth.
- **Asset condition and criticality:** We consider the condition, risk of failure, and importance of assets when prioritising renewals and replacements. This helps maintain network performance and supports the long-term resilience of our network.
- **High impact and unforeseen events:** Some investments are designed to reduce exposure to low likelihood but high consequence events, or to provide contingency for unplanned needs. These support our preparedness for unforeseen and resilience scenarios.

## High impact low probability risks and mitigation

Some risks, although unlikely to occur, have the potential to cause widespread disruption and serious consequences for our network, customers, and community. These high impact low probability events are a critical part of our planning and require specific attention to ensure readiness and resilience. This proactive approach helps ensure that we are prepared for low probability events and capable of protecting our people, our services, and the wider community when disruption strikes.

The risks we monitor in this category include events that could result in significant service outages, asset damage, or safety impacts. While the probability of occurrence is low, the consequences are high enough to justify focused mitigation. Examples of high impact low probability risks include:

- **Major earthquakes:** Seismic events with the potential to damage key network assets or critical infrastructure.
- **Severe weather:** Extreme wind, flooding, or snow events that exceed historical patterns and stress system limits.
- **Grid-wide failure:** Widespread loss of supply due to national grid outages or major substation failures.
- **Catastrophic equipment failure:** Failure of large-scale assets such as power transformers or high voltage switchgear.
- **Extended supply disruption:** Long delays in accessing critical materials or equipment due to supply chain breakdowns.
- **Cyber intrusion:** Targeted cyber attacks affecting operational technology or control systems.

To mitigate these risks, we apply a combination of forward planning, targeted investment, and operational readiness. Key measures include:

- **Scenario planning:** Structured assessments to understand potential impacts and guide response preparation.
- **Critical spares:** Provisioning of spare equipment, rotable assets, and contingency resources to enable rapid recovery.
- **Resilient design:** Investment in asset upgrades and system configuration to strengthen network resilience.
- **Response planning:** Development of emergency plans for high consequence scenarios with clear response protocols.
- **Coordinated response:** Collaboration with other lifeline utilities, emergency services, and sector partners to support a joined-up recovery.
- **Ongoing review:** Monitoring of emerging threats and evolving risks to keep response plans current and relevant.

## Emergency response plan

Electricity is a critical service in any emergency. As a designated lifeline utility under the Civil Defence Emergency Management Act, we have a responsibility to support the safety and wellbeing of our community before, during, and after major events. Our emergency management approach is structured around the Four Rs (Reduction, Readiness, Response, and Recovery) which guide our planning, preparation, and participation in the wider emergency management system. We:

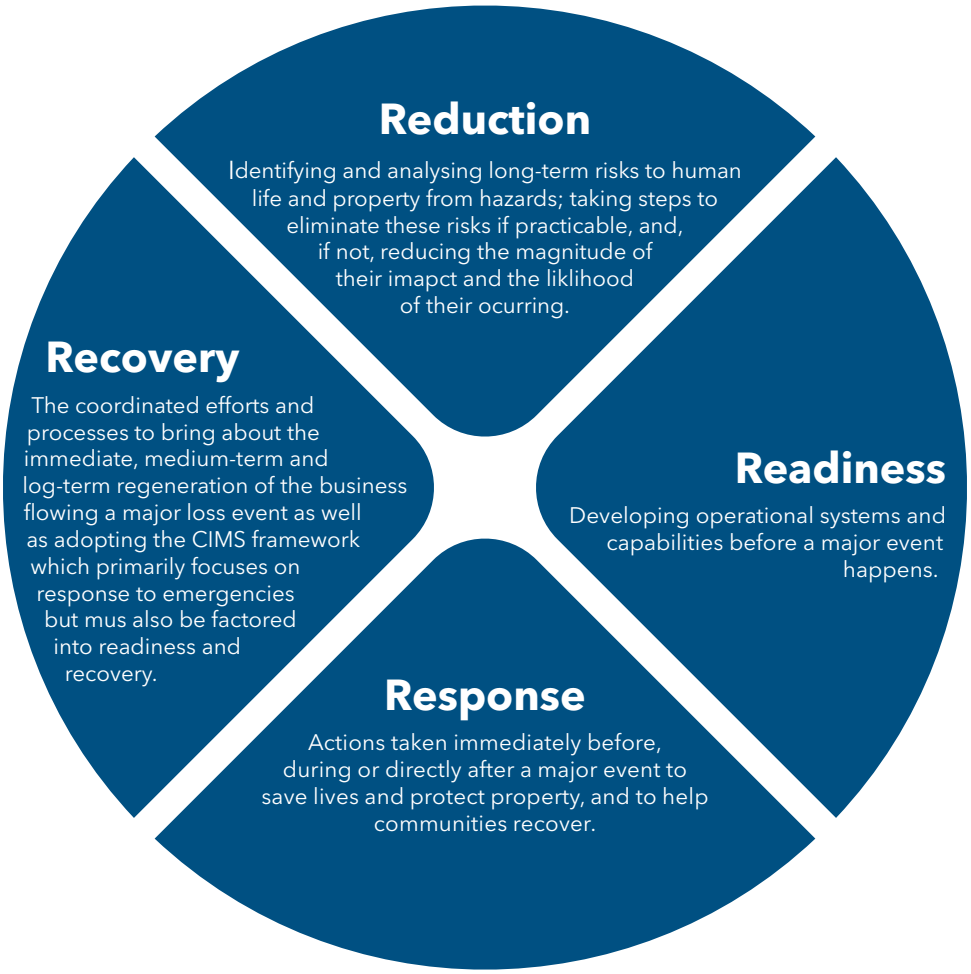
- **Reduction:** Reduce risk through resilient asset design, condition-based maintenance, and targeted investment in critical infrastructure
- **Readiness:** Prepare our people, systems, and procedures through training, scenario

planning, and regular emergency exercises

- **Response:** Act promptly to minimise disruption, restore power safely, and coordinate effectively with emergency services
- **Recovery:** Support regional recovery efforts by restoring electricity supply and providing technical assistance to other lifeline agencies

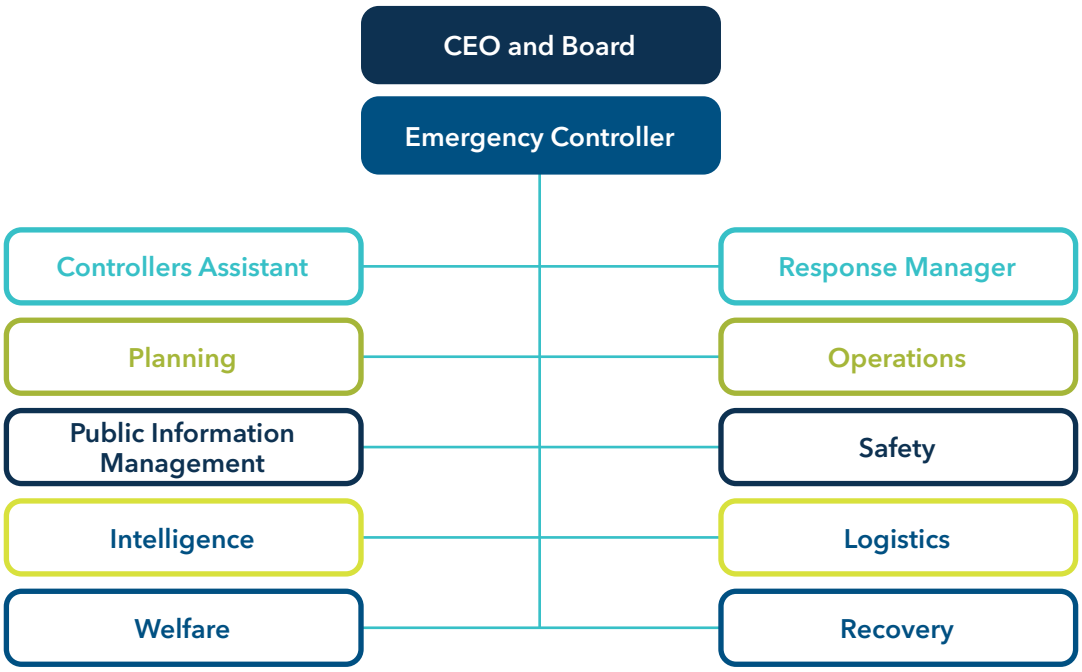
Our responsibilities extend beyond our own operations. We work closely with emergency services, regional lifelines groups, and other utilities to plan coordinated responses. These partnerships strengthen our collective readiness and help ensure that essential services are restored quickly and effectively when they are needed most.

*Figure 104 | 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 105 | Emergency response structure*




Our emergency management responsibilities are only fully realised through the strength of our partnerships. These relationships ensure that emergency actions are coordinated, response roles are understood, and resources can be mobilised quickly when needed. We engage regularly with emergency services, lifeline utility partners, and regional civil defence groups to align plans, share situational awareness, and improve our collective ability to manage disruption.

These efforts support practical delivery during major events. For example, joint training exercises with lifeline groups help build familiarity across agencies, while shared planning with other utilities reduces duplication and strengthens critical service restoration. By embedding stakeholder collaboration into our emergency response arrangements, we are better positioned to protect essential services and accelerate recovery for our community.

## Cyber resilience and information security

Technology plays an essential role in how we manage, control, and deliver electricity. As our reliance on digital systems grows, so too does our exposure to cyber threats. These threats range from unauthorised access and data breaches to sophisticated attacks on systems that control critical infrastructure. The consequences include operational disruption, financial loss, reputational harm, and safety risks. A proactive stance on cyber resilience ensures that we are equipped to manage these evolving threats and maintain the confidence of our customers, our community, and our partners

We treat cyber resilience as a core component of operational integrity. Our approach focuses on anticipating threats, strengthening defences, and responding quickly to incidents. It supports our operational scenarios of Operation, Resilience, and Unforeseen by protecting critical services and reducing the risk of prolonged outages. Key elements of our cyber resilience and information security approach include:

- **Identify cyber risks:** Assess vulnerabilities across information systems, operational technology, and supplier interfaces to understand where threats may emerge
- **Apply security controls:** Protect access points, secure critical systems, and implement monitoring to detect unauthorised activity
- **Build incident response:** Develop tools and capability to detect, contain, and recover from cyber events with minimal disruption

- **Meet compliance requirements:** Ensure alignment with legal, regulatory, and sector standards for cyber security and critical infrastructure protection
- **Collaborate with partners:** Share intelligence and coordinate with industry groups, regulators, and cyber security specialists to strengthen shared resilience
- **Integrate with planning:** Link cyber resilience to business continuity, emergency management, and operational risk planning

## Critical spares strategy and supply chain resilience

Access to critical spares is essential to restoring service quickly, managing faults, and responding to emergencies. Our supply chain resilience strategy ensures we can continue operations even when supply conditions are constrained. It supports service reliability, reduces repair times, and strengthens our ability to manage risks across planned and reactive work. The ability to secure and deploy the right equipment, components, and materials underpins both our routine operations and our readiness for unexpected events.

We manage critical spares based on risk, asset importance, and operational need. This involves identifying critical items based on their function, failure risk, and role in network performance. We use asset data and business continuity requirements to determine spare quantities and their storage locations. Spares are stored under appropriate conditions, maintained to ensure usability, and rotated to preserve stock quality. For long lead time items or those sourced from constrained markets, we secure supply early to mitigate the risk of delays.

Supply chain resilience extends beyond physical inventory. We work closely with manufacturers, service providers, and vendors to maintain reliable procurement channels and manage contractual risks. Our approach also includes procurement planning, contract management, and supplier performance monitoring. During emergencies or wider disruptions, we coordinate with industry peers and regional lifeline partners to share access to critical equipment and maintain operational continuity.

## Resilience intelligence and data-driven risk management

Informed decisions are central to effective risk management and long-term resilience. We rely on asset data, operational performance records, and structured risk intelligence to guide planning, prioritisation, and investment. This enables us to anticipate issues before they escalate, direct maintenance where it is needed most, and allocate resources to strengthen network reliability and community outcomes.

Our approach combines data analytics with risk modelling and practical engineering insight. Resilience intelligence supports both daily operations and long-term strategies by embedding risk signals into how we plan, invest, and respond. We monitor asset condition, performance, and service history to identify patterns and detect early warning signs. This data is then applied through models such as Condition-Based Asset Risk Management (CBARM) to assess asset criticality and determine where intervention is needed. Predictive modelling and scenario analysis help us understand how different risks could affect network performance and guide our response.

We integrate these insights into our capital planning and project selection processes to ensure that resilience investment is targeted and effective. Our models and inputs are regularly reviewed and refined to improve decision accuracy. These efforts are also aligned with our regulatory obligations, customer service goals, and regional resilience outcomes.

## Data-driven resilience decisions

By using resilience intelligence, our team identifies concerns on our network, target upgrades more effectively, and prepare for disruption with greater confidence. This approach draws on real-time asset data and risk modelling to guide investment where it makes the biggest impact. From weather-driven outages to ageing infrastructure, every decision is grounded in evidence and tailored to local conditions. The result is a stronger, more reliable electricity supply that can adapt to change and meet the evolving needs of our communities.

Building organisational capability is essential to sustaining a resilient and responsive network. Our resilience intelligence strategy is strengthened by the people who operate it, the processes that guide it, and the systems that support it. To ensure that our operational readiness keeps pace with emerging risks, we place strong emphasis on capability development across our workforce and service providers.

We draw lessons from previous events, conduct structured internal reviews, and engage with other electricity distribution businesses to refine our practices. This learning culture enables us to adapt quickly, respond decisively, and maintain service even under pressure. Training programmes are tailored to strengthen emergency management, hazard response, and business continuity awareness, while scenario-based exercises and simulations help test our response in realistic conditions.

Our competence register ensures we track skills, qualifications, and role readiness across critical functions, including contractors. Leadership development focuses on decision making under stress, while encouraging organisational learning from both success and failure. These activities are underpinned by a shared culture of responsibility, where resilience and risk awareness are treated as part of everyday operations rather than one-off exercises.

Together, these efforts ensure that we have the right capability in place to manage risk, protect essential services, and maintain confidence in our ability to respond to whatever challenges may arise.

## 9.3. Our resilience

Resilience is shaped not just by the strength of our infrastructure, but by the choices we make, the capability of our people, and our commitment to those we serve. It is strengthened through experience, improved through learning, and reinforced by trusted partnerships across our region.

Resilience remains part of how we operate, not an outcome we pursue once a challenge has arrived. It is our awareness of the environment we operate in, our readiness to adapt, and our shared responsibility that ensure we can continue to deliver essential services under all conditions. During the period of this AMP, we will be focusing on:

- **Improve operational readiness:** Refine planning and response capabilities to ensure faster, more flexible actions during network disruptions and emergencies.
- **Embed risk awareness:** Integrate evolving risk considerations into asset strategies, planning processes, and investment decisions across the organisation.
- **Address climate adaptation:** Continue to develop and apply targeted responses to climate-related risks, aligning with broader organisational and sector resilience goals.
- **Support regional lifelines:** Remain actively involved in regional and district lifelines workstreams to coordinate emergency planning and infrastructure readiness.
- **Link decarbonisation to resilience:** Use infrastructure upgrades related to national decarbonisation as an opportunity to strengthen system resilience and performance.
- **Strengthen local networks:** Support decentralised energy systems and localised generation to improve flexibility, fault tolerance, and service continuity.
- **Plan for extreme weather:** Advance weather risk modelling, asset design, and response

planning to reduce the impact of severe events on network performance.

We monitor how well our risk and resilience activities are working to ensure they stay effective and relevant. This includes formal reviews, audits, and lessons learned after incidents and exercises. We use tools such as the Resilience Management Maturity Assessment to assess our organisational capability and guide development where needed.

What we learn from events, both real and simulated, is used to refine our plans, improve our procedures, and strengthen our training. We report progress regularly to governance and leadership teams to maintain transparency and keep accountability strong. Through engagement with industry forums and regulatory bodies, we stay aligned with sector expectations and emerging risks.

Improvement is part of our routine. Insights gained from monitoring are built into our business planning, works programme, and staff development. It is not something we do after something goes wrong, it is how we continue to do better every day. By maintaining this cycle of review and action, we ensure our strategies support reliable service, strong readiness, and practical risk control.

# 10. 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 chapter describes the capital and operational expenditure needed to deliver the plans set out in this AMP, explains the key projects we expect to undertake in the coming year, and highlights the principal changes from the previous AMP and the reasons behind them.

## 10.1. Overview

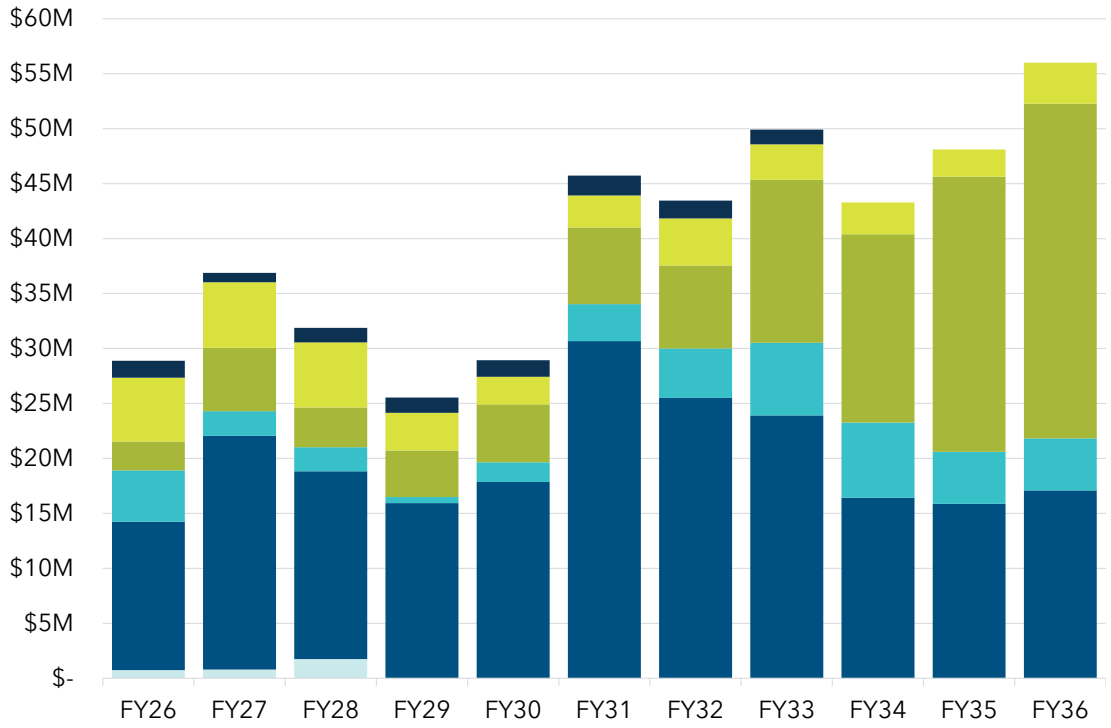
Our forecasts reflect the best information available at the time of publication. They draw on updated asset condition insights, refreshed demand projections, climate and resilience considerations, and the investment planning assumptions set out in Section 3. While these projections form a robust baseline, they are influenced by factors outside our direct control. These include the assumptions of our strategic AMP around shifts in customer demand and needs, climate impacts, emerging technologies and regulatory development, and wider economic conditions. As these uncertainties unfold, our forecasts will be refined through annual AMP updates and scenario analysis.

All values in this chapter are presented in constant prices, consistent with Schedules 11a and 11b in Appendix D. Our 10-year budget provides a transparent view of our foreseen expenditure over the planning period.

## 10.2. 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 106 | Total network CAPEX by category*




Our network capital programme reflects a measured lift in renewal, resilience, and growth investment across the next ten years. Figure 106 presents the forecast expenditure by category, showing how our programme evolves as condition issues intensify, climate pressures increase, and demand signals gradually strengthen across the region. The shape of the programme also reflects the financial envelope set by DPP4, which influences timing and sequencing in the early years of the planning period.

In FY27 the programme rise as more renewal work becomes unavoidable and as system growth pressures begin to re-emerge. From FY28 to FY31, the programme eases as more renewal work is stabilised and as system growth pressures begin to re-emerge. The ongoing electrification of industrial customers, the need to maintain readiness for potential step loads, and the preparation required for the new Timaru supply point all contribute to a gradual uplift. A more pronounced step up occurs from FY31 onward. At this point, several drivers converge. Condition based renewal requirements increase, climate resilience work becomes more significant, and major system growth projects begin to move into execution to ensure that new loads can connect without delay. The uplift also reflects the lead times associated with sub-transmission reinforcement and the coordinated investments required to support the long-term capacity of the network. By the end of the period, System Growth becomes one of the largest contributors to total expenditure, reinforcing the need to position the network for future industrial and commercial demand.

Across the entire programme, Customer Connections and Non-Network CAPEX provide steady contributions, reflecting predictable work volumes and the ongoing need to invest in digital tools and systems. The provisional allowance reduces gradually as planning confidence improves and as better asset condition and demand data become available.

The increase in network CAPEX over the planning period reflects updated asset condition evidence, maturing climate and weather risk pressures, and the need to maintain readiness for future industrial and commercial growth. Figure 107 compares the 2025 AMP and the 2026 AMP forecasts and shows how our investment profile has been reshaped to reflect these drivers. The recalibration in the early years is deliberate. It aligns investment with our latest growth forecasts, internal delivery capacity, and the timing of the highest risk reduction opportunities. For FY27 the 2026 AMP rises above the 2025 AMP as critical renewal projects require investment. From FY28

to FY32, the 2026 AMP remains lower than the 2025 AMP, reflecting delayed demand growth expectations, more accurate condition information, and a focus on delivering the most critical renewal and resilience projects first.

From FY32 onward, the trend reverses. The 2026 AMP rises above the 2025 AMP as major system growth projects begin to emerge. This uplift is necessary to ensure the network is prepared for future industrial electrification, potential step loads, and the long-term capacity requirements associated with the new supply arrangements for Timaru. The smoother profile across the mid-period also reduces the risk of over-investment during uncertain years while maintaining our commitment to remain connection ready for new customers.

Overall, the updated forecast represents a more disciplined, evidence based, and strategically sequenced 10-year investment programme that balances affordability, delivery capability, and the need to strengthen long-term network resilience and capacity.

*Figure 107 | Comparison of Network CAPEX in 2026 AMP and 2025 AMP*

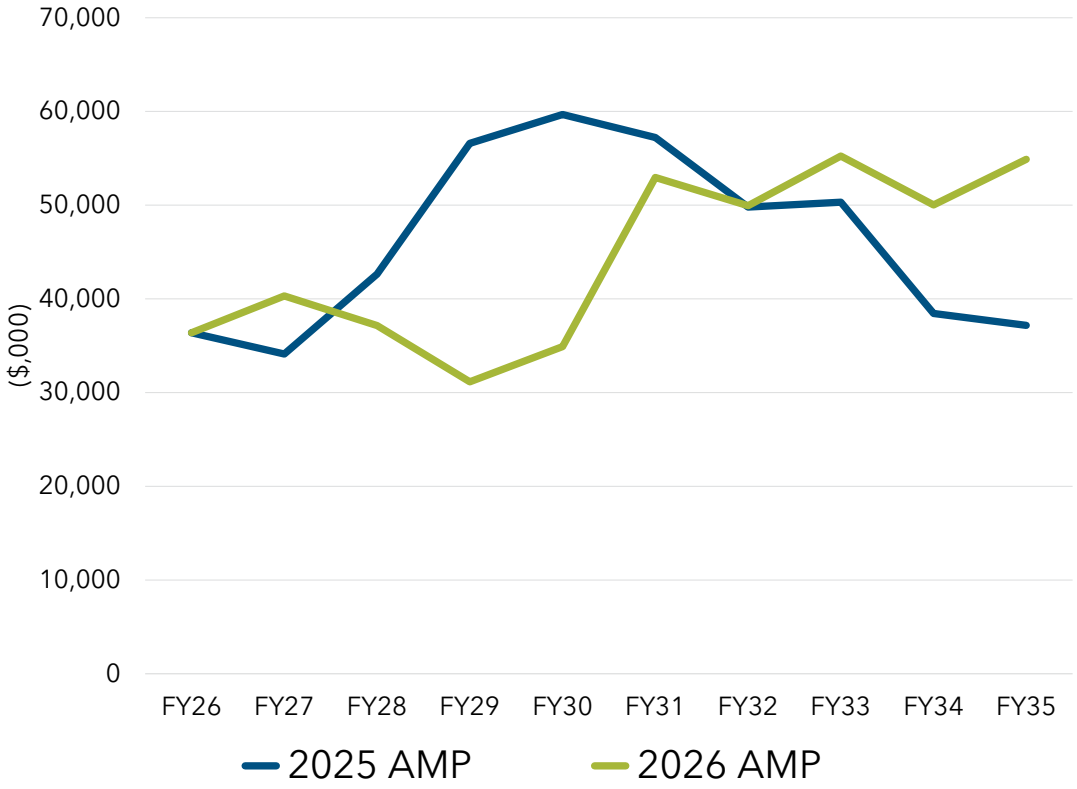



Table 57 below shows the variance by network CAPEX category between the 2026 to 2035 AMP and the previous AMP across the overlapping nine years. The pattern reflects a programme that has been refined with stronger asset condition intelligence, updated demand and capacity signals. The most material variances occur in asset replacement and renewal, system growth, and customer connections, where updated risk evidence and revised assumptions have reshaped the timing and scale of investment.

Customer connection expenditure is lower than last year's forecast in and fluctuates between FY28 and FY30, before moving higher from FY31 onward. This pattern reflects updated expectations for connection activity, revised assumptions about the timing of industrial and commercial developments, and more accurate design and cost allocation within the prudent scenario.

System growth shows the largest movements. Lower expenditure in FY28 to FY33, reflected in negative variances, arises from revised sequencing of major growth projects and updated demand timing. These shifts reflect a more disciplined and evidence informed approach to planning. The strong positive variances in FY27, and again in FY34 to FY35 occur because several major system growth activities are now forecast to take place later in the period than previously

assumed, rather than continuing at the levels shown in the previous AMP.

Asset replacement and renewal variances reflect a deeper understanding of asset condition and failure risk. Some fleets require earlier intervention based on updated asset health indicators, while others have been deferred following improved field information. This produces a mixture of negative and positive variances, with an overall trend toward earlier renewal of higher risk assets and smoother sequencing across the planning window.

Reliability, safety, and environmental expenditure is slightly higher in FY27 and FY28, materially lower in FY29 and FY30, and then higher from FY31 onward. The negative variances in the middle years reflect a deliberate reprioritisation, with fewer standalone resilience or safety initiatives scheduled than in last year's AMP as effort shifts toward increasing the overhead line work rate. The positive variances from FY31 onward reflect the timing of later reliability, safety, and environmental work rather than a broad uplift across the whole period.

In total, the variance pattern shows a programme that has been strengthened through better evidence, improved sequencing, and clearer alignment with the timing of risk reduction projects. The early years remain close to our practical capacity to perform the work required, while the middle of the period reflects lower expenditure expectations as growth, renewal, and resilience work is rephased. The positive variance in the later years of the comparison period reflects the movement of major projects further out in the planning window rather than a reduction in future need.

*Table 57 | Variance in Network Capital Expenditure*

| | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 | FY35 |
|---|---|---|---|---|---|---|---|---|---|
| **Consumer connection** | -1,042 | 1,088 | -1,091 | -34 | 1,034 | 91 | 660 | 723 | 789 |
| **System growth** | 1,614 | -9,443 | -12,565 | -7,955 | -12,605 | -8,583 | -5,165 | 8,805 | 23,120 |
| **Asset replacement and renewal** | 4,520 | -1,067 | -7,291 | -10,273 | 6,114 | 3,479 | 3,256 | -3,966 | -8,719 |
| **Asset relocations** | - | - | - | - | - | - | - | - | - |
| **Reliability, safety and environment:** | 184 | 428 | -6,524 | -6,666 | 2,445 | 3,340 | 5,440 | 5,680 | 2,680 |
| **Total** | **5,276** | **-8,994** | **-27,471** | **-24,928** | **-3,013** | **-1,673** | **4,191** | **11,242** | **17,870** |

## 10.3. Material projects

The material projects in our programme represent the highest priority investments required to address ageing assets, emerging constraints, and areas where security of supply must be strengthened. They are essential to managing critical risks and ensuring that the network remains connection ready for future customer demand.

A project is classified as material when expenditure exceeds $1 million, when it involves a critical asset, or when deferring the work would create an unacceptable consequence for customer supply. These projects reflect the most significant needs identified through our condition data, resilience assessments, and long-term planning assumptions, and together they form a disciplined and targeted investment response. The projects outlined in chapter 4 and in this AMP provide a consolidated view of the material investments planned for the period of this AMP.

# 10.4. Variance from 2025-35 AMP

Last year's AMP showed a 10-year network CAPEX forecast of $433 million. This has remained the same over the same period. The main material changes are summarised in Table 58 below.

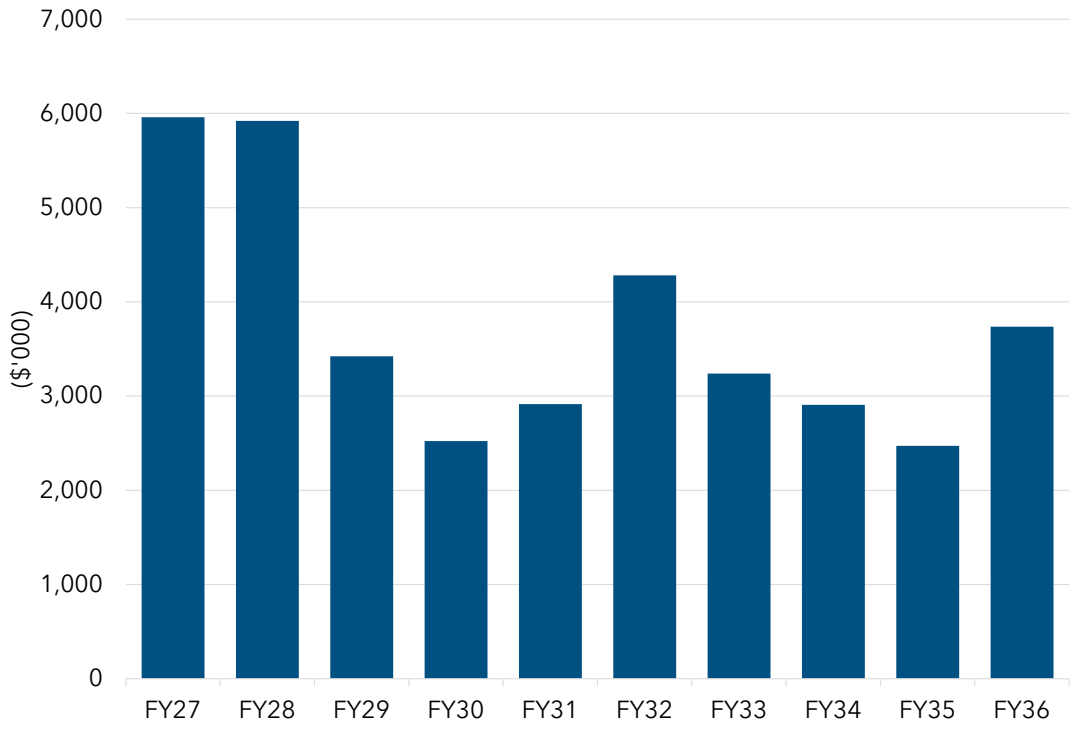
*Table 58 | Variance Drivers Underlying The Reduced Ten Year Network CAPEX Forecast*

| Programme Description | Forecast Change ($'000) |
|---|---|
| Our consumer connection forecast increases to reflect stronger activity and expectations over the 10-year period. Last year we anticipated around $65.1 million of connection related investment. We now expect around $69.5 million as the outlook for customer driven work strengthens. | 4,383 |
| System growth increases as the forecast now provides for a larger programme of capacity investment to support future load growth and emerging demand requirements. Last year we forecast around $116.8 million over 10 years. We now expect around $120.8 million as growth needs are confirmed more clearly. | 4,010 |
| Asset replacement and renewal decreases as the programme is now more tightly sequenced and refined around the highest priority renewal needs. Last year we forecast around $215.1 million over 10 years. We now expect around $201.6 million, reflecting revised timing and scope across the renewal portfolio. | -13,489 |
| Asset relocations decreases slightly as fewer relocation works are currently identified across the planning period. Last year we forecast around $3.3 million over 10 years. We now expect around $2.6 million. | -750 |
| Reliability, safety and environment increases as the forecast includes a larger programme of work to address safety, reliability, and environmental risks across the network. Last year we forecast around $32.4 million over 10 years. We now expect around $40.5 million as these needs are better defined. | 8,116 |
| Total | 2,270 |

## 10.5. Non-network CAPEX

The total forecast non-network CAPEX for the 10-year planning period is shown in Figure 108. The profile reflects the ongoing lifecycle replacement of our digital equipment, mobile and computing devices, communications hardware, fleet, plant, and property assets. These activities ensure that the essential tools and support systems required to operate the network remain reliable, secure and fit for purpose. The fluctuations in the expenditure pattern reflects the timing of vehicle replacements, property redevelopment, or higher volumes of equipment renewals. This scheduling maintains our operational capability while supporting resilience, data integrity and the safe operation of field and control systems across the business.

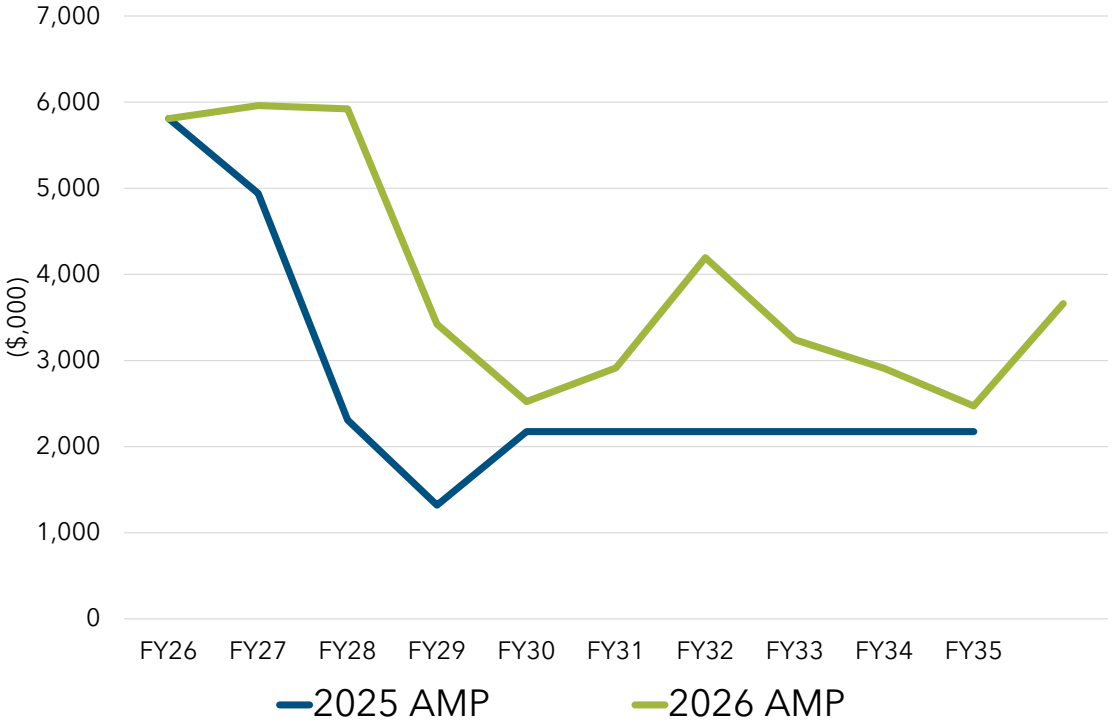
*Figure 108 | Non-network CAPEX*




The non-network CAPEX profile represents the planned renewal of the digital and operational assets that enable day-to-day network management. It covers the replacement of digital network equipment, computing and mobile devices, communications hardware, vehicle fleet, plant, and property. These activities follow lifecycle requirements across the business, ensuring that critical tools and supporting systems are kept current.

Compared with the previous AMP, the updated forecasts show a revised expenditure pattern. As shown in Figure 109, non-network CAPEX in the 2026 AMP is higher in the early years due to updated timing for digital renewals and adjustments to fleet and property planning. From FY29 onward, the revised phasing provides a more accurate view of non-network asset lifecycle needs and aligns investment with the timing of planned replacements and improvements.

*Figure 109 | Comparison of Non-network CAPEX in 2026 AMP and 2025 AMP*




Last year's AMP showed a forecast of $21.6 million for the nine overlapping years (FY27 - FY36), which has now increased by $1.6 million to $23.3 million. This change reflects a shift from broad allowances to detailed and fully costed lifecycle planning. The updated AMP applies clearer condition information, more accurate pricing, and firmer scheduling of renewals across plant, fleet, metering, facilities, and digital systems. These refinements provide a more realistic view of the investment required to maintain the tools, equipment, and support assets that enable day to day network operations. The main contributors to the increase are summarised in Table 59 below.

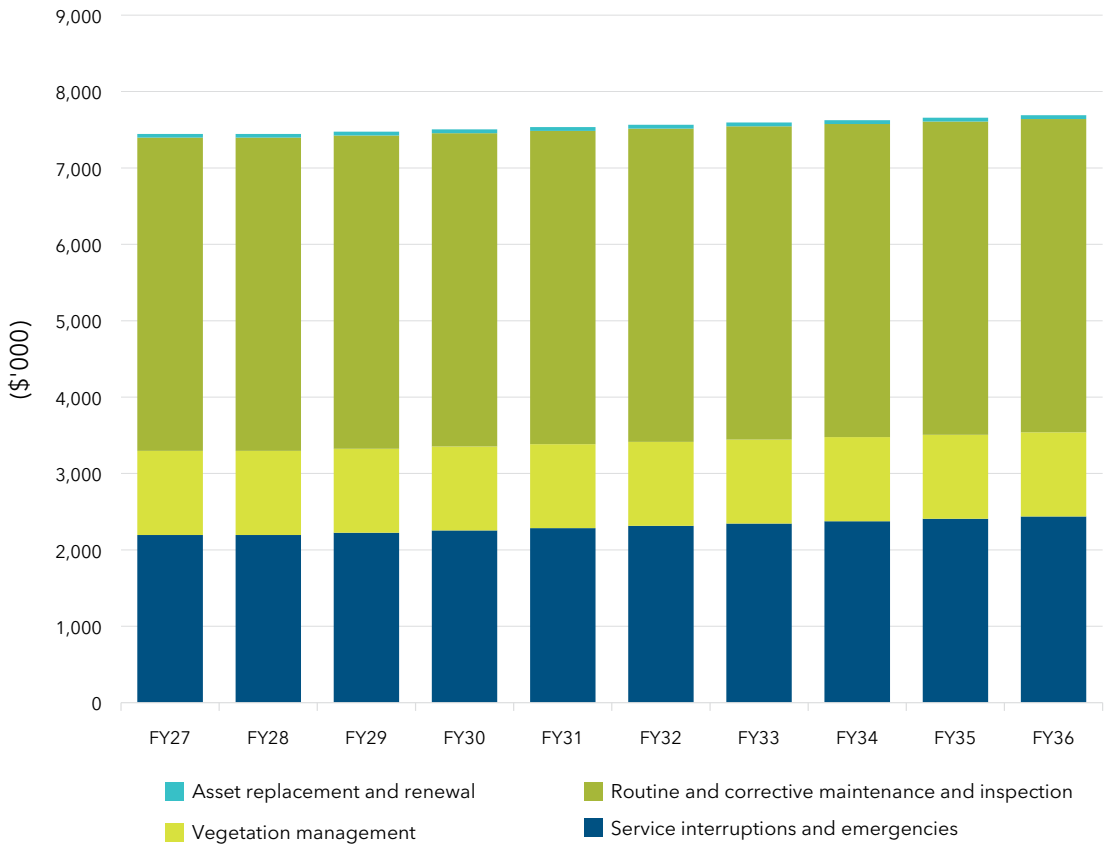
*Table 59 | Non-Network CAPEX Variance*

| Project Investment | Forecast Change ($'000) |
|---|---|
| **Plant and Equipment:** The Plant and Equipment forecast decreased as the expenditure that previously sat within this broader category is no longer carried in the same way. ThisNon-Network Plant and Equipment forecast group became redundant. | -6960 |
| **Vehicles:** The Fleet forecast increased and provides a clearer view of the timing and scale of vehicle renewals needed to support field operations. This reflects a more explicit view of the timing and scale of vehicle renewals needed across the next ten years. | 7,160 |
| **Land and Buildings:** The Property forecast increased and includes a larger programme of yard and facility investment in the early years. This provides a clearer view of the expenditure needed to maintain safe, functional, and fit for purpose operational yard and workspace. | 1,400 |
| **Digital Equipment:** The Digital forecast is broadly unchanged across the comparable years, with the updated AMP maintaining the same renewal profile for digital equipment over most of the period. We established a regular refresh programme for network and infrastructure equipment, computers, and mobile devices from 2027 onward, creating a sustained and more accurate baseline for digital renewals across the period. | 0 |
| Total | 1,600 |

# 10.6. Network OPEX

The total forecast network OPEX for the 10-year period is shown in Figure 110. The profile reflects the core activities required to operate, maintain and support the network each year. This includes routine and corrective maintenance, vegetation management, asset renewal and replacement work, and response to service interruptions and emergencies. The expenditure stays relatively stable across the period, with movements in individual years driven by inspection cycles, renewal activity, and expected emergency response requirements. These activities ensure that field operations, network performance and customer service levels remain reliable and consistent.

*Figure 110 | Total network OPEX by category*




The overlapping 9-year period from FY27 to FY35 shows a $2.7 million increase in the network OPEX forecast from $65.1 million in last year's 2025 AMP to $67.8 million in this 2026 AMP. Vegetation management increased the forecast by $900k, and a targeted adjustments to our routine maintenance profiles increased the forecast by $1.8 million.

*Figure 111 | Comparison of Network OPEX in 2026 AMP and 2025 AMP*

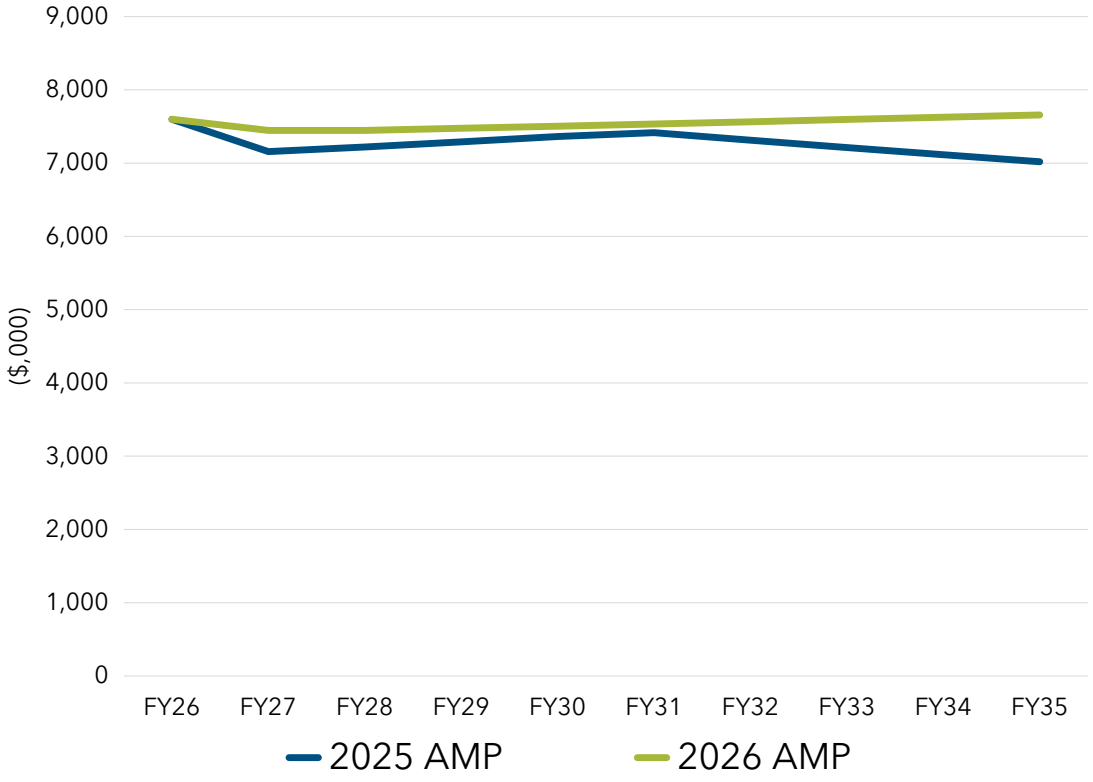



Table 60 below sets out the variance by network OPEX category for the overlapping 9-year period from FY27 to FY35. The figures show the difference between the 2025 AMP and this updated AMP.

*Table 60 | Change in Network OPEX [$'000] When Compared with the Previous AMP*

| | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 | FY35 |
|---|---|---|---|---|---|---|---|---|---|
| **Service interruptions and emergencies** | 0 | -26 | -22 | -18 | -146 | -116 | -85 | -54 | -23 |
| **Vegetation management** | 91 | 82 | 73 | 64 | 85 | 106 | 126 | 146 | 166 |
| **Routine and corrective maintenance and inspection** | 196 | 167 | 130 | 91 | 174 | 255 | 334 | 411 | 487 |
| **Asset replacement and renewal** | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| **Total** | 288 | 225 | 184 | 141 | 118 | 250 | 382 | 512 | 639 |

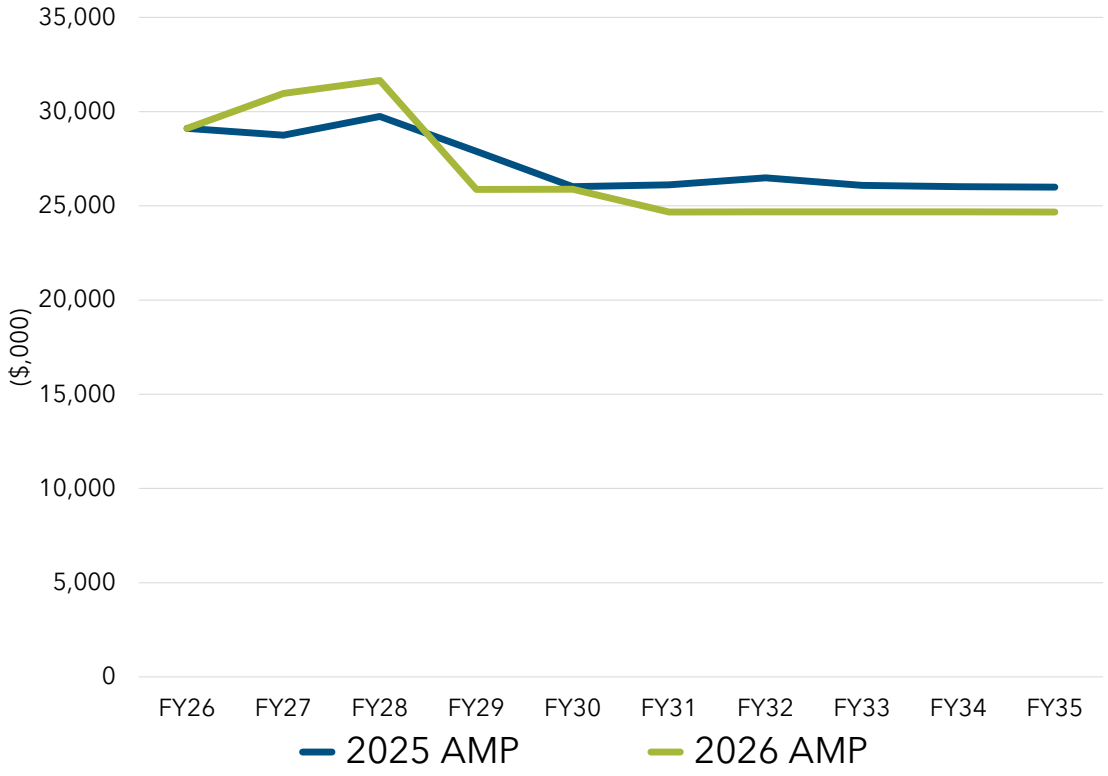
Service interruptions and emergencies decrease across most years, reflecting efficiency gains in our response approach and improved network reliability. Vegetation management shows an increase, driven by the planned uplift in inspection and cutting activity to maintain the latest clearance standards. Routine and corrective maintenance and inspection increase materially, reflecting an increase in overhead line inspection work. Asset replacement and renewal varies slightly to accommodate licensing fees from year to year. This pattern of variances demonstrates a revised operational profile that maintains service levels, managing risk, and supporting reliability outcomes.

## 10.7. Non-network OPEX

Our forecast for non-network operating expenditure has reduced from $271 million in the 2025 AMP to $266 million in this AMP. This change reflects a moderated view of future cost pressures and a clearer understanding of the drivers that sit behind our Business Support and System

Operations and Network Support activities. The updated forecast incorporates the step increase required in FY27 and FY28 to deliver our transformation programme in the early years, followed by a return to a more stable operating profile as implementation work concludes and efficiency gains are realised. The overall reduction indicates that the long-term cost base can be sustained at a lower level without increasing operational risk or compromising service quality.

*Figure 112 | Comparison of non-network OPEX in the 2026 AMP and the 2025 AMP*



# 11. How we will deliver our AMP

This chapter outlines how we will deliver the investment programme set out in this AMP. It reflects the scale and complexity of our planned works, and the evolving expectations of customers, regulators, and stakeholders. Our delivery strategy is designed to ensure we have the capability, systems, and partnerships in place to execute safely, efficiently, and transparently.

We focus on three core dimensions of delivery:

- **9.1. Delivery approach** – strengthening our delivery model and capacity.
- **9.2. Lifting our productivity across network delivery and operations** – lifting productivity in network delivery and operation.
- **9.3. Collaborating for sector efficiency** – demonstrating faster, deeper collaboration and standardisation to address fragmentation, unlock efficiencies, and support electrification at scale.

Together, these dimensions ensure we are well-positioned to deliver on our strategic outcomes and regulatory obligations over the 2026–2036 period.

## 11.1. Delivery approach

Our delivery approach is evolving to meet the scale, complexity, and expectations of our 2026–2036 works programme. Our commitment to aligning our capabilities with our forward-looking AMP is supported by the move to an integrated field delivery model. We recognise that people with the critical skills, and the development of our people is essential for successful delivery of the work programme. Our delivery model will strengthen capability, improve responsiveness, and streamline execution. In parallel, we are strengthening our preferred supplier model for externally delivered work. This reflects our commitment to managing more of our programme in-house while maintaining flexibility and efficiency through strategic external partnerships.

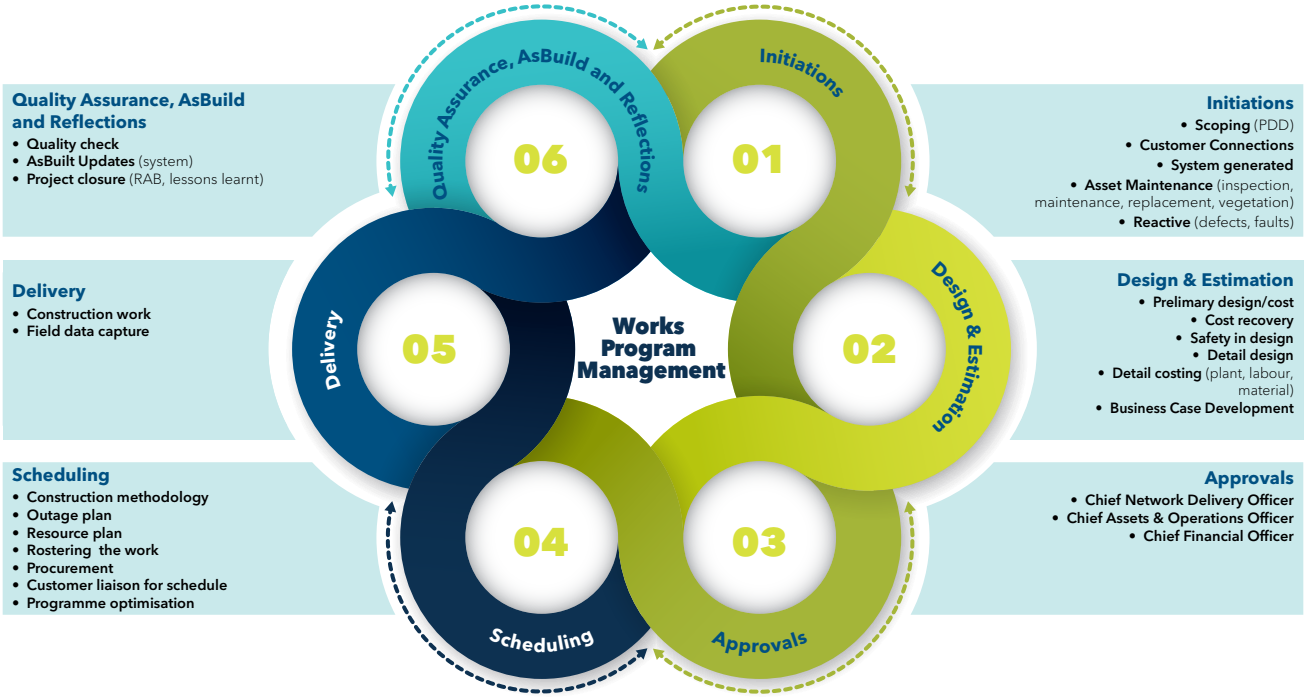
We are focused on ensuring that our delivery model supports the safe, timely, and cost-effective execution of capital, maintenance, and customer-initiated works, while enabling continuous improvement and alignment with our strategic outcomes.

### Delivery model

Our delivery model enables us to directly manage a greater share of the works programme, while retaining flexibility to engage external providers through a preferred supplier framework.

We are transitioning to a new delivery model underpinned by digital transformation that will grow our capacity to deliver a larger, more complex works programme. Figure 113 below depicts the new operating model

*Figure 113 | New delivery model*




Our delivery maturity is being underpinned by four key areas:

- **Streamlining and improving efficiency:** The integration of the field services contractor into the main business has consolidated our field services into a single accountable structure. We are now focused on strengthening in-house project management, improving efficiencies and handoffs across the delivery lifecycle, and embedding risk-based prioritisation via the Works Programme Committee.
- **Smarter sourcing and governance:** We are transitioning to a preferred supplier model for externally delivered work, enabling more consistent delivery outcomes and cost certainty. This is supported by clearer commercial frameworks and improved procurement coordination.
- **System and process maturity:** We continue to invest in delivery tracking tools (e.g. AdaptiveWork), ERP integration, and safety systems to support end-to-end visibility and control.
- **Workforce and safety leadership:** To sustain delivery, we are investing in people systems, role clarity, and safety initiatives.

Our Delivery Team remains responsible for ensuring the successful execution of all network capital expenditure and operational expenditure. 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 in-house project management professionals work collaboratively across the business and with customers and service providers, tailoring the delivery of work to achieve the best possible outcome for our network and our communities.

The remainder of this section outlines our current delivery model across capital works, maintenance, customer-initiated projects, and major works. This is followed by a discussion of how we manage our overall programme delivery, ensuring coordination, visibility, and resilience across all work types, and how we continue to build our capacity and secure the skills we need.

## Delivery model by work type

### 1. Capital works delivery

We follow a structured and transparent five-stage process for capital works delivery:


1. **Identification:** We assess network requirements through defect reporting, load studies, and customer work requests.

2. **Justification:** We undertake risk assessments, load studies, demand forecasting, feasibility analysis, and develop project scope and cost projections.

3. **Design:** We establish project teams, conduct site surveys, consult stakeholders, appraise assets, and finalise scope and cost. Safety in Design (SiD) reviews precede comprehensive design. Long-lead equipment is ordered early to mitigate supply chain risks.

4. **Procurement:** We prepare contract documentation and job packs, and procure additional equipment and materials as needed. While competitive tendering remains an option, we are transitioning to a preferred contractor framework to improve cost-effectiveness and delivery speed.

5. **Delivery:** Construction is now managed internally where possible, with the field services contractor fully integrated into our field services team. If internal capacity is constrained, projects are passed to our procurement team for external delivery. We monitor cost, schedule, quality, and risk throughout using Adaptive Work to track delivery milestones.

### Maintenance works delivery

We have shifted from a unit rate model to an actual cost transfer model for maintenance and inspections, resulting in true cost reflection in operational expenditure. Maintenance is delivered through a structured preventive maintenance program tailored to asset type, location, and criticality.

Key activities include routine inspections, transformer maintenance, switchgear maintenance, substation equipment inspections and checks, ground-mounted distribution switchgear maintenance, secondary systems inspections, and vegetation management.

Maintenance projects and tasks are scoped and monitored by our Service Delivery and Asset Lifecycle teams. We conduct regular reviews of delivery outcomes to refine our maintenance specifications and improve reliability and performance.

### Customer-initiated work

Our Customer Commercial team manages the identification, scoping, and feasibility of customer-initiated projects (e.g., subdivisions, commercial connections). Procurement and delivery are managed by Service Delivery, with physical works completed by the customer's chosen provider. We maintain oversight to ensure compliance and quality.

Section 3 covers our customer connection practices in more detail.

### Major projects

Major projects are typically AMP-identified works or large customer connections. We use in-house project management and may tender specialist electrical and civil components separately to

maintain competitive tension and ensure high-quality outcomes. To support delivery, we provide the field crew with a forward works programme at least three months prior to the financial year.

## Programme delivery management

This section outlines how we manage the delivery of our overall works programme, ensuring visibility, coordination, and resilience across all work types. It complements the preceding sections on delivery models for capital, maintenance, customer-initiated, and major works by focusing on programme-level practices that enable us to deliver safely, efficiently, and with minimal disruption.

### Coordinating significant works

To deliver a larger and more complex programme over the 2026–2036 period, we are embedding 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 providers 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[3].
- 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.

We continue to engage with councils, utilities, and stakeholders to align project windows and minimise disruption. Our Works Programme Committee uses a risk-based framework to sequence projects and integrate non-network options (e.g., flexibility, DER) where economic.

### Works pipeline visibility

We maintain visibility of future work volumes and types through structured planning and forecasting processes. This supports internal coordination, contractor engagement, and delivery efficiency. Key practices include:

- **Annual Network Development Plans (NDPs)** for each GXP region, developed using bottom-up demand forecasting, scenario modelling, and asset capability assessments.
- **Use of ETAP modelling and CRM data** to track customer enquiries, step loads, and distributed generation applications, which inform forward work volumes.
- **Demand categorisation by likelihood and timing**, enabling us to sequence projects and assess delivery risk.
- **Continuous monitoring and feedback loops**, including asset inspections and performance reviews, to refine forecasts and adjust delivery plans.
- **Structured governance via the Works Programme Committee**, which oversees programme coordination, risk management, and delivery alignment with strategic priorities.

3 Works Programme Committee: Provides governance over Alpine's works programme; monitors delivery, reviews escalated issues, and supports ELT investment decisions. See section 5.1 for more detail.

These practices ensure we can proactively manage delivery demand, maintain workforce stability, and support efficient execution across all work types.

### Works cost management

We apply a structured and transparent approach to works cost management to ensure affordability, delivery efficiency, and alignment with strategic outcomes.

Our delivery model supports cost management through:

- A unified internal delivery structure with clear accountability for core functions.
- Integrated programming and scheduling via the Works Programme Committee.
- A multi-year planning approach that enables prioritisation and sequencing of works.
- Transition to actual cost transfer for maintenance and inspections.
- Preferred supplier frameworks for external delivery, supporting cost certainty and delivery speed.
- Ongoing refinement of cost estimation practices, supported by AdaptiveWork and ERP integration.

These practices ensure we can deliver a growing and complex works programme while maintaining financial discipline and transparency.

### Delivery risk management

We manage delivery risk through structured forecasting, scenario planning, and investment prioritisation, including:

- **Step-load likelihood categorisation:** All large customer connections and demand increases are assessed using a probability framework (Confirmed, Very Likely, Likely, Possible, Speculative), enabling us to anticipate delivery risk and adjust investment timing accordingly.
- **Scenario-based forecasting:** We model multiple growth scenarios (Speculative, Possible, Prudent) to understand the impact of electrification, DG uptake, and economic shifts on delivery feasibility.
- **Risk-informed investment prioritisation:** Projects are evaluated against criteria including safety, reliability, efficiency, and ease of implementation. This ensures delivery risk is considered upfront in capital allocation.
- **Continuous feedback loops:** Insights from asset inspections, network performance, and customer engagement are fed back into planning to refine forecasts and mitigate emerging risks.
- **Governance oversight:** The Works Programme Committee monitors delivery risks through project reviews, change requests, and resource planning, ensuring alignment with our strategic outcomes.

This approach allows us to manage delivery risk dynamically, with decisions grounded in data, probability, and structured governance.

## Building our capacity

The competition for skilled labour in the sector is intensifying. Electrification, digitalisation, and climate resilience are driving demand for new capabilities across engineering, field services, and programme delivery. We must compete with other high-growth sectors for talent, while also developing the specialist skills needed to deliver our AMP.

To build capacity, we are activating multiple levers:

- **Innovative recruitment:** We continue to evolve our recruitment approach, with a strong focus on strengthening our employer brand. We have moved beyond traditional advertising channels by using role specific and values based recruitment videos that showcase our people, our work, and the lifestyle Alpine Energy offers. These videos provide candidates with a realistic and engaging insight into working with us, supporting better informed applications and stronger alignment.
- **Retention and development:** We offer flexible work arrangements, targeted training, and clear career pathways to retain and grow our people. Our people strategy is informed by market trends and internal capability reviews.
- **Collaboration with other EDBs and industry bodies:** We actively participate in working groups and joint initiatives to share resources, access specialist skills, and shape sector-wide responses to workforce challenges. This includes engagement with Electricity Networks Aotearoa and other South Island EDBs.
- **Contractor capability uplift:** We work closely with service providers to support workforce planning, training, and safety leadership. This ensures our contractors are equipped to deliver our programme safely and efficiently.

These efforts are essential to ensure we can deliver our AMP safely, reliably, and at scale.

## Lifting our productivity across network delivery and operations

Delivering more for less is a central challenge for our business and the wider sector. With rising expectations from customers, regulators, and shareholders, and a constrained cost environment, productivity is now a priority.

The Minister for Energy has made it clear that EDBs must reverse the sector's long-term decline in total factor productivity (TFP), as identified in the CEPA report commissioned by the Commerce Commission.[4] The sector's 1.4% decline in TFP from 2008 to 2023 underscores the need for tangible, measurable efficiency gains. We are committed to responding to this challenge with urgency and transparency.

Internally, we are focused on lifting productivity across all stages of **network delivery** from planning, design through to construction. This includes reducing duplication, improving cost visibility, and embedding digital tools that streamline workflows and enable smarter decision-making.

Our productivity uplift is not limited to network delivery. It also applies to **network operations and maintenance** – spanning customer services, asset management, digital systems, and commercial operations. We are investing in the systems, metrics, and capabilities needed to track performance, identify bottlenecks, and continuously improve.

4 Cambridge Economic Policy Associates (CEPA). (2024, June 24). EDB productivity study: A report prepared for the Commerce Commission.

### Assets and network delivery

These initiatives focus on the planning, execution, and management of works (capital, maintenance, and customer-initiated projects) ensuring efficient, timely, and cost-effective delivery.

- **Standardisation and digitisation** – when applied to delivery processes, e.g., standard designs and materials for works execution.
- **Expand standard designs and materials** – directly impacts delivery efficiency and consistency.
- **Streamline value-chain processes to reduce rework and truck-rolls** – targets delivery process improvements and operational efficiency in field execution.
- **Recruit a Delivery Performance Manager to lead commercial and efficiency analysis** – role focused on improving delivery outcomes and commercial performance.
- **Connection process improvements** – standard templates, queue management, and faster approvals for connections are part of the delivery workflow.
- **Voluntarily permit ≥10 kW export per connection where safe, ahead of code changes** – a delivery-side initiative to enable customer connections and future-proof the network.
- **Leverage ePMO tool to track end-to-end delivery –** digital enablement for delivery tracking and milestone management.

### Network operations and maintenance

These initiatives focus on the ongoing management, monitoring, and optimisation of the network – automation, data analytics, and operational systems.

- **Accelerate network automation (e.g., remote switching)** – directly relates to operational efficiency and automation of network functions.
- **Advance OMS/ADMS roadmap and LiDAR deployment** – operational systems for outage management, advanced distribution management, and asset monitoring.
- **Performance measurement and benchmarking** – operational metrics and benchmarking for continuous improvement.
- **Adopt internal productivity metrics** (e.g., $ per MW enabled, rework rate, automated device coverage) – metrics for operational performance and productivity.
- **Digital enablement** – continue investment in GIS, CRM, and data analytics to reduce duplication and improve planning accuracy.

## 11.2. Collaborating for sector efficiency and innovation

The sector must demonstrate faster, deeper collaboration and standardisation to address fragmentation, unlock efficiencies, and support electrification at scale.

We are pursuing collaboration pragmatically to deliver our AMP. We recognise that many of the challenges we face – workforce constraints, rising costs, and the need for flexible, customer-centric solutions – cannot be solved in isolation. We must work with our peers, partners, and communities to build shared capability, reduce duplication, and deliver better outcomes for customers.

We also see collaboration as a lever for innovation. By pooling insights, standardising processes, and co-investing in shared platforms, we can accelerate the adoption of new technologies and business models, particularly in areas like DER integration, outage management, and customer connections.

This AMP outlines the collaborative initiatives already underway, and other focus areas for us to refine and implement:

- Shared delivery frameworks:
  - Develop a preferred contractor framework with EDBs , enabling shared crews, agreed rates, and guaranteed minimum expenditures.
  - Compare internal vs external delivery costs to inform sourcing decisions.
- Procurement:
  - 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.
- Place-based partnerships:
  - Co-plan with councils, Waka Kotahi and lifeline utilities to align road corridors and project windows.
  - Support regional resilience planning and sustainability initiatives through joint investment and coordination.
- Joint workforce development:
  - Explore shared workforce models and joint training programmes to address labour shortages and support delivery capacity across the region.
- Sector standardisation:
  - Contribute Alpine's templates (standards, investment cases, design packs) to sector working groups.
  - Develop DSO capabilities that support coordinated CER integration and flexible demand management.
  - Collaborate with industry peers to develop climate-resilient construction standards and embed these into our design and delivery practices.
- Open data and transparency:
  - Publish queue and hosting-capacity data.
  - Share DER approval metrics and connection turnaround times.
  - Develop shared platforms for pricing, outage, and distributed generation management.
- Innovation partnerships and shared learning:
  - Formalise innovation partnerships with other EDBs, EECA, and Transpower.
  - Establish shared learning pathways to accelerate capability uplift and adoption of new technologies.
- Community energy partnerships:
  - Investigate co-investment models with community groups to support local generation, resilience, and affordability outcomes.

These initiatives reflect our strategic shift toward being a proactive collaborator, with more deliberate regional and industry partnerships. They also support our broader strategic outcomes by enabling smarter infrastructure, customer choice, and financial resilience.

## 11.3. Measuring our success

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.

*Table 61 | Our health and safety targets*

| | Actual 2024/2025 | Targeted 2025/2026 | Targeted 2026/2027 | Targeted 2027/2028 |
|---|---|---|---|---|
| **Business safety** | | | | |
| Safety experience scores | 76% | 85% | 87% | 90% |
| Critical Risk reviews | 4 | 4 | 4 | 4 |
| Safety Assurance completion | N/A | 90% | 92% | 95% |
| **Public safety** | | | | |
| Number of serious injury events[5] involving members of the public | 0 | 0 | 0 | 0 |
| Number of public safety awareness campaigns | 12 | 10 | 10 | 10 |

### Our network reliability performance targets

SAIDI and SAIFI remain the standard industry measures for network reliability. These metrics are calculated in accordance with the Commerce Commission's Default Price-Quality Path (DPP) Determination, which sets fixed limits for planned and unplanned outages over each five-year regulatory period.

For the 2026 AMP, our business is now operating under the fourth regulatory period (DPP4), which commenced on 1 April 2025. DPP4 introduces updated input methodologies and quality standards, with a stronger emphasis on resilience and service quality.

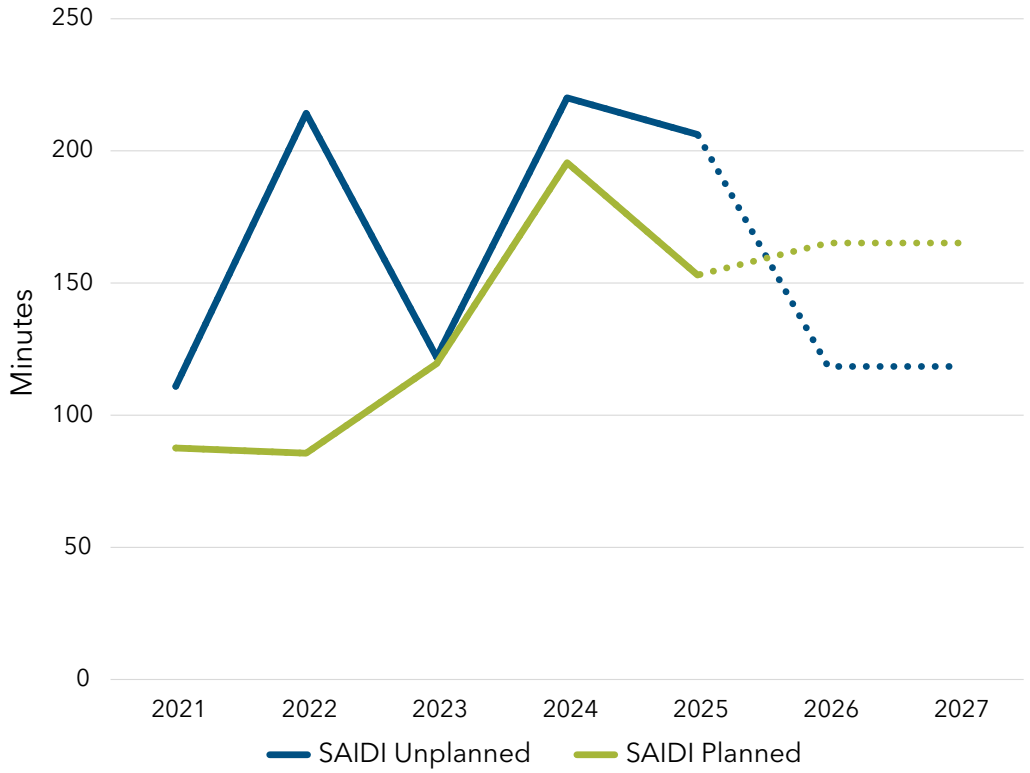
Our investment programme is structured to maintain reliability performance indicators consistent with DPP4 requirements, while balancing affordability. Our SAIDI and SAIFI targets for the 2025–2030 regulatory period reflect these updated standards and will be reported annually in accordance with Information Disclosure requirements.

We continue to embed customer feedback into our planning and maintain transparency with stakeholders through AMP disclosures, ID reporting, and ongoing engagement.

Our recent SAIDI performance, shown in Figure 115, provides useful context for the reliability targets that apply under DPP4. The past five years show considerable variation in unplanned outages, driven largely by weather events and the condition of overhead line assets, while planned outages reflect the scale and timing of maintenance and renewal work. Unplanned SAIDI rose sharply in 2022 and 2024 due to significant weather related faults. Planned SAIDI follows the pattern of our work programme, increasing when major renewal activity is undertaken in urban areas.

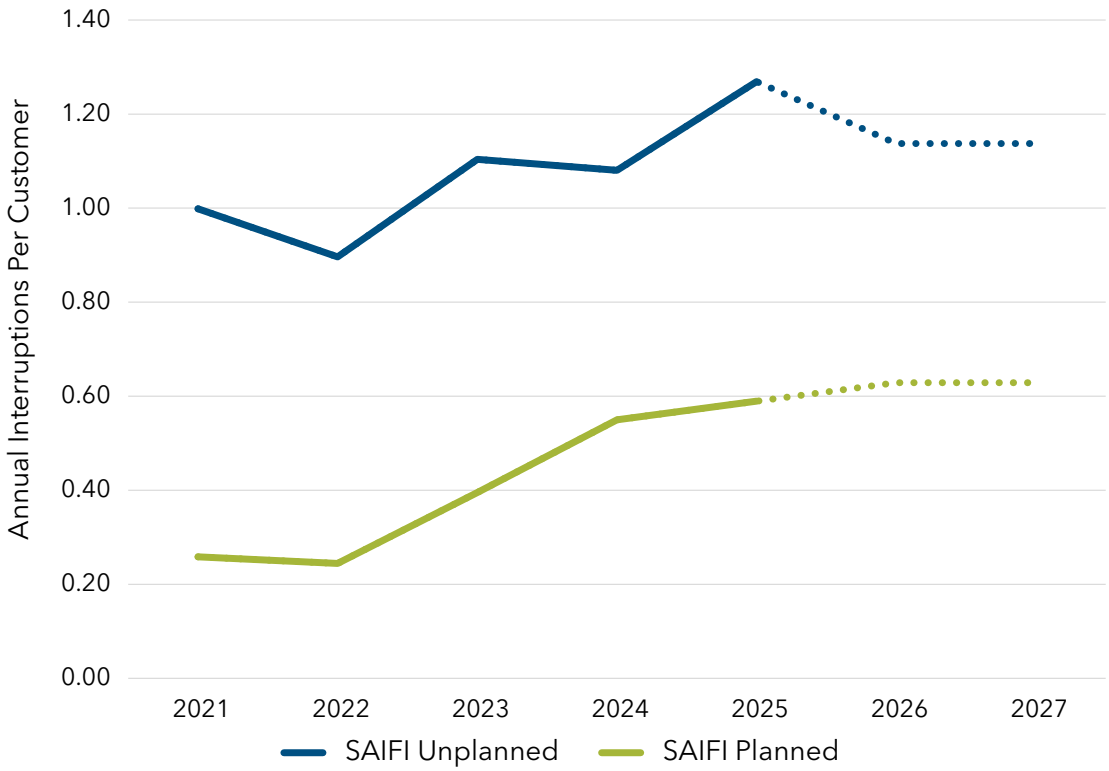
5 Excluding third party contact e.g., car vs. pole.

*Figure 115 | SAIDI performance (2021-2025) and targets (2026 – 2027)*




SAIFI measures how frequently customers experience power interruptions over a year, and together with SAIDI it forms the core of our reliability assessment under DPP4. The recent trend shows relatively stable unplanned interruption frequency, moving from 1.00 in 2021 to 1.27 in 2025 before easing slightly across the forecast period. Planned interruptions have increased gradually as more asset renewal work is scheduled, rising from 0.26 in 2021 to around 0.63 from 2026 onward. This pattern reflects the shift toward proactive asset renewal and the larger volumes of planned field activity required to manage condition risks and strengthen network resilience. The forecast for 2026 and 2027 illustrates a steady reliability outlook, consistent with the investment strategy outlined in this AMP and aligned with DPP4 quality expectations.

*Figure 116 | SAIFI performance (2021-2025) and targets (2026 – 2027)*




## Maturing our approach to measuring customer experience

Looking ahead, we recognise that traditional reliability indicators such as SAIDI and SAIFI—while essential for regulatory reporting—do not fully capture the day-to-day experience of all customers across our network. As our customer-experience approach matures, we will expand our analysis beyond network-wide averages by monitoring performance at each of our seven GXP regions and developing more granular metrics that better reflect the outcomes our investment programme is intended to deliver.

This includes building a clearer understanding of how interruption performance is distributed across different customer groups, enabling us to assess not only the average level of service but also the variability around it. These insights will enhance our ability to deliver a more consistent, predictable, and equitable service, while strengthening the transparency between planned improvements, delivered investments, and the real-world outcomes experienced by customers. They will also inform the development of our Strategic Reliability Management Plan (SRMP).

The SRMP will bring together the reliability interventions available to us into a structured framework spanning network augmentation, non-network solutions, operational response measures, and targeted capital and operational initiatives such as sectionalising devices and vegetation management. Drawing on contemporary reliability practices from New Zealand and Australia, and grounded in our own network planning and operational experience, the SRMP will establish a multi horizon approach to reliability management that complements the investment strategy set out in this AMP.

# 12. Appendices

## Appendix A: Glossary

| Acronym/term | Definition |
|---|---|
| **ADMS** | Advanced Distribution Management System |
| **AHI** | Asset Health Indicators |
| **AM** | Asset Management |
| **AMP** | Asset Management Plan |
| **AMMAT** | Asset Management Maturity Assessment Tool |
| **AS/NZS** | Australian / New Zealand Standard |
| **CAIDI** | Customer Average Interruption Duration Index |
| **CAPEX** | Capital Expenditure |
| **CBAM** | Carbon Border Adjustment Measure |
| **CBARM** | Condition-Based Asset Risk Model |
| **CEPA** | Cambridge Economic Policy Associates |
| **$CO_2$** | Carbon Dioxide |
| **ComCom** | Commerce Commission |
| **CRM** | Customer Relationship Management |
| **CPI** | Consumer Price Index |
| **DER** | Distributed Energy Resources |
| **DG** | Distributed Generation |
| **DSM** | Demand-Side Management |
| **EAM** | Enterprise Asset management |
| **EDB** | Electricity Distribution Business |
| **EDBs** | Electricity Distribution Businesses |
| **ERP** | Enterprise Resource Planning |
| **ESG** | Environmental, Social, and Governance |
| **ETAP** | Electrical Transient and Analysis Program |
| **EV** | Electric Vehicle |
| **F&O** | Finance and Operations |
| **GHG** | Greenhouse Gas |
| **GIS** | Geographic Information System |
| **GXP** | Grid Exit Point |
| **H&S** | Health and Safety |
| **HILP** | High Impact Low Probability |
| **HV** | High Voltage |

| | |
|---|---|
| **ICP** | Installation Control Point |
| **ICT** | Information and Communications Technology |
| **IED** | Intelligent Electronic Device |
| **ID** | Information Disclosure |
| **IM** | Input Methodology |
| **ISO** | International Organisation for Standardization |
| **kV** | Kilovolt |
| **kVA** | kilovolt-ampere |
| **LiDAR** | Light Detection and Ranging |
| **LV** | Low Voltage |
| **Markov modelling** | A probabilistic modelling technique used to predict how asset condition will change over time |
| **MVA** | megavolt-ampere |
| **MW** | Megawatt |
| **MWh** | megawatt-hour |
| **NDP** | Network Development Plan |
| **OMS** | Outage Management System |
| **OPEX** | Operating Expenditure |
| **OT** | Operational Technology |
| **PMO** | Programme Management Office |
| **PV** | Photovoltaic |
| **RMMAT** | Resilience Maturity Model Assessment Tool |
| **RMU** | Ring Main Unit |
| **RTU** | Remote Terminal Unit |
| **SAIDI** | System Average Interruption Duration Index |
| **SAIFI** | System Average Interruption Frequency Index |
| **SCADA** | Supervisory Control and Data Acquisition |
| **$SF_6$** | Sulphur Hexafluoride |
| **SNA** | Significant Natural Areas |
| **SOI** | Statement of Corporate Intent |
| **SoS** | Security of Supply |
| **SoSS** | Security of Supply Standard |
| **$tCO_2e$** | tonnes of carbon dioxide equivalent |
| **UHF** | Ultra High Frequency |
| **VHF** | Very High Frequency |
| **V2G** | Vehicle-to-Grid |
| **V2H** | Vehicle-to-Home |

# 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 11.3 |
| 1.2 | Monitoring and continuously improving asset management practices; | Section 5.3 |
| 1.3 | Close alignment with corporate vision and strategy; | Section 4.2 |
| 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 |
| 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 7.3 |
| 1.7 | An emphasis on optimising asset utilisation and performance; | Section 7.3 |
| 1.8 | That a total life cycle approach should be taken to asset management; | Section 5.2<br>Section 7.3 |
| 1.9 | That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered. | Section 6.4 |
| **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 5 |
| 2.2 | Are clearly documented and made available to all stakeholders; | All sections |
| 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; | All sections |
| 2.4 | Specifically support the achievement of disclosed service level targets; | Section 11.3 |
| 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 9 |
| 2.6 | Consider the mechanics of delivery including resourcing; | Section 11 |
| 2.7 | Consider the organisational structure and capability necessary to deliver the AMP; | Section 11 |
| 2.8 | Consider the organisational and contractor competencies and any training requirements; | Section 11 |
| 2.9 | Consider the systems, integration and information management necessary to deliver the plans; | Section 8 |
| 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; | All sections |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 2.11 | Promote continual improvements to asset management practices. | All sections |
| **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 4.1 |
| 3.4 | Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed; | 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 3.1 |
| 3.7 | A description of the accountabilities and responsibilities for asset management on at least 3 levels, including governance, executive and field operations - | Section 5.1 |
| 3.8 | All significant assumptions: | Section 4.2 |
| 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 4.2 |
| 3.10 | An overview of asset management strategy and delivery; | Section 4 and 11 |
| 3.11 | An overview of systems and information management data; | Section 8 |
| 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 8 |
| 3.13. | A description of the processes used within the EDB for- | |
| 3.13.1 | Managing routine asset inspections and network maintenance; | Section 5.2 Section 7.3 |
| 3.13.2 | Planning and implementing network development projects; and | Section 6.2 Section 11.1 |
| 3.13.3 | Measuring network performance; | Section 11.3 |
| 3.14 | An overview of asset management documentation, controls and review processes. | Section 4.3 |
| 3.15 | An overview of communication and participation processes; | Section 3.2 |
| 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 | All sections |
| | **Assets covered:** | |
| 4 | The AMP must provide details of the assets covered, including - | |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 4.1 | A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including- | Section 2.1<br>Section 6.3 |
| 4.1.1 | The region(s) covered; | Section 2.1<br>Section 6.3 |
| 4.1.2 | Identification of large consumers that have a significant impact on network operations or asset management priorities; | Section 6.3 |
| 4.1.3 | Description of the load characteristics for different parts of the network; | Section 6.3 |
| 4.1.4 | Peak demand and total energy delivered in the previous year, broken down by sub-network, if any. | Section 6.3 |
| 4.2 | A description of the network configuration, including- | |
| 4.2.1 | Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; | Section 6.3 |
| 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 6.3 |
| 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 6.3 |
| 4.2.5 | A description of the low voltage network including the extent to which it is underground; and | Section 7.3 |
| 4.2.6 | An overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems. | Section 7.3 |
| 4.3 | If sub-networks exist, the network configuration information referred to in sub clause<br>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- | |
| 4.4.1 | Voltage levels; | Section 7.3 |
| 4.4.2 | Description and quantity of assets; | Section 7.3 |
| 4.4.3 | Age profiles; and | Section 7.3 |
| 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 7.3 |
| 4.5. | The asset categories discussed in clause 4.4 should include at least the following- | |
| 4.5.1. | The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); | Section 7.3 |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 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 11.3 |
| 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 11.3 |
| 7 | Performance indicators for which targets have been defined in clause 5 above should also include- | |
| 7.1 | Consumer oriented indicators that preferably differentiate between different consumer types; | Section 3<br>Section 11.3 |
| 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. | Section 11.3 |
| 8 | The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets. | Section 11.3 |
| 9 | Targets should be compared to historic values where available to provide context and scale to the reader. | Section 11.3 |
| 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. | N/A |
| | **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 6.2 |
| 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 6.2 |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 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 7.3 |
| 11.4 | The use of standardised designs may lead to improved cost efficiencies. This section should discuss- | Section 7.3 |
| 11.4.1 | The categories of assets and designs that are standardised; | Section 7.3 |
| 11.4.2 | The approach used to identify standard designs. | Section 7.3 |
| 11.5 | A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network. | Section 3.4 |
| 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 6.2 |
| 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 6.2 – 6.3 |
| 11.8.1 | Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; | Section 6.2 |
| 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 6.3 |
| 11.8.3 | Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and | Section 6.3 |
| 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 6.3 |
| 11.9 | Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including- | Section 6.2 |
| 11.9.1 | The reasons for choosing a selected option for projects where decisions have been made; | Section 6.2 |
| 11.9.2 | The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; | Section 6.4 |
| 11.9.3 | Consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment. | Section 6.4 |
| 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 6.3 |
| 11.10.1 | A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; | Section 6.1 |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 11.10.2 | A summary description of the programmes and projects planned for the following four years (where known); and | Section 4.2<br>Section 6.1 |
| 11.10.3 | An overview of the material projects being considered for the remainder of the AMP planning period. | Section 4.2<br>Section 6.3 |
| 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 6.3 |
| 11.12 | A description of the EDB's policies on non-network solutions, including- | Section 6.4 |
| 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 6.4 |
| 11.12.2 | The potential for non-network solutions to address network problems or constraints. | Section 6.4 |
| | **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 7.2 |
| 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 7.3 |
| 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 7.3 |
| 12.2.2 | Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and | Section 7.3 |
| 12.2.3 | Budgets for maintenance activities broken down by asset category for the AMP planning period. | Section 7.3 |
| 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 7.3 |
| 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 7.3 |
| 12.3.2 | A description of innovations made that have deferred asset replacement; | Section 7.3 |
| 12.3.3 | A description of the projects currently underway or planned for the next 12 months; | Section 7.1 |
| 12.3.4 | A summary of the projects planned for the following four years (where known); and | Section 4.2<br>Section 7.1 |
| 12.3.5 | An overview of other work being considered for the remainder of the AMP planning period. | Section 7.3 |

| | 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 7.3 |
| 12.5 | Identification of the approach used for developing capital expenditure projects for lifecycle asset management, including an explanation of: | Section 7.3 |
| 12.5.1 | Approach used to inform capital expenditure projections for lifecycle asset management | Section 7.3 |
| 12.5.2 | The rationale for using the approach for each asset category | Section 7.3 |
| 12.6 | Identification of vegetation management related maintenance, including an explanation of the approach and assumptions used to inform vegetation management related maintenance | Section 7.3 |
| 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 7.3 |
| | **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 8.4 |
| 13.2 | Development, maintenance and renewal policies that cover them; | Section 8.4 |
| 13.3 | A description of material capital expenditure projects (where known) planned for the next five years; | Section 8.4 |
| 13.4 | A description of material maintenance and renewal projects (where known) planned for the next five years. | Section 8.4 |
| | **Risk management:** | |
| 14 | AMPs must provide details of risk policies, assessment, and mitigation, including– | |
| 14.1 | Methods, details and conclusions of risk analysis; | Section 9.2 |
| 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 9.2 |
| 14.3 | A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2; | Section 9.2 |
| 14.4 | Details of emergency response and contingency plans. | Section 9.2 |
| | **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 11.3 |
| 15.2 | An evaluation and comparison of actual service level performance against targeted performance; | Section 11.3 |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 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 5.3 |
| 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 5.3 |
| | **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 11.1 |
| 16.2 | The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans. | Section 11.1 – 11.2 |
| | **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 6.4 |
| 17.2.1 | The EDB's practices for monitoring voltage quality on its low voltage network | Section 6.4 |
| 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 6.4 |
| 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 6.4 |
| 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 3 |
| 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 3.2 |
| 17.3.2 | The EDB's approach to planning and managing customer complaint resolution | Section 3.2 |
| 17.4 | Practices for connecting new consumers and altering existing connections | Section 3 |
| 17.4.1 | A description of the EDB's practices for connecting consumers, including the EDB's approach to planning and management of: | Section 3 |

| | Contents of the amp clause | AMP section |
|---|---|---|
| 17.4.1(a) | Connecting new consumers, and overcoming commonly encountered issues | Section 3 |
| 17.4.1(b) | Alterations to existing connections | Section 3 |
| 17.4.2 | How the EDB is seeking to minimse the cost to consumers of new or altered connections | Section 3 |
| 17.4.3 | The EDB's approach to planning and managing communication with consumers about new or altered connections | Section 3 |
| 17.4.4 | Commonly encountered delays and potential timeframes for different connections | Section 3 |
| 17.5 | A description of the following: | |
| 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 6.3 |
| 17.5.1(b) | How the EDB takes the timing and uncertainty of new demand generation, or storage capacity into account | Section 6.3 |
| 17.5.1(c) | How the EDB takes other factors into account, eg, the network location | Section 6.3 |
| 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 |
| 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 3.4<br>Section 6.4 |
| 17.6.2 | The EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers | Section 4<br>Section 11.2 |
| 17.6.3 | How the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt or discontinue these practices | Section 8.3 -8.4 |
| 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 11.2 |
| 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 11.2 |
| 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. | |

# Appendix C: Region schematic diagrams

This appendix contains the schematic Single Line Diagrams for each region.

## Albury

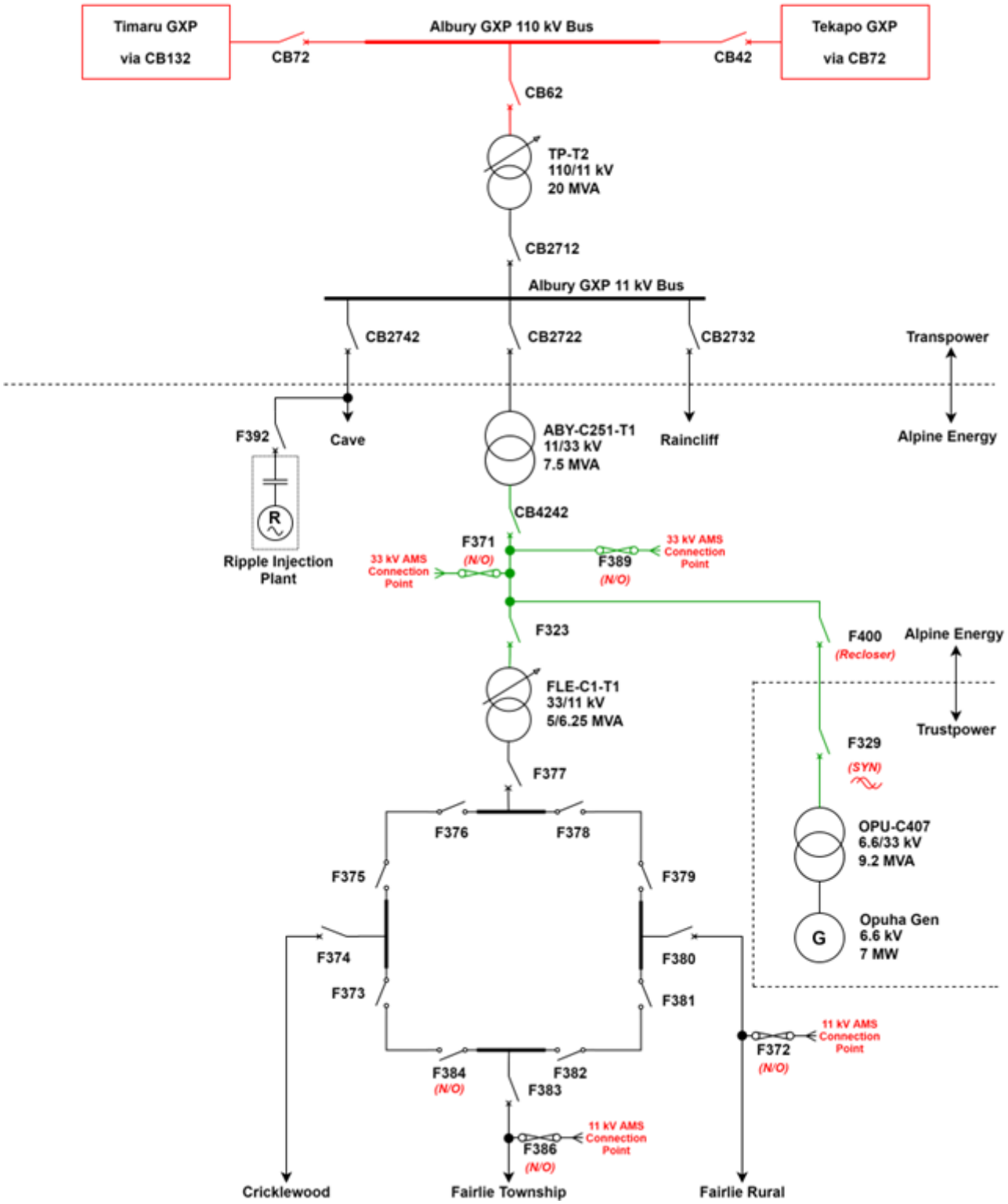
The Albury GXP is fed off the TIM–TKA 110 kV line and has a single 110/11 kV 20 MVA transformer connected to an 11 kV switchboard. The Transformer was upgrade in 2017 from 6 to 20 MVA. These are Transpower assets.

We take supply from three feeder circuit breakers, two of which supply the 11 kV distributions feeders around Albury. The remainder 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. This same 33 kV feeder connects to the Opuha power station 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 surrounds rural area.

# Albury Region Network Overview



## Bells Pond GXP

Bells Pond GXP is a single tee off the STU–OAM–WTK2 110 kV Transpower transmission circuit. The GXP is essentially a 110 kV metering point with Alpine Energy owning and operating the 110/33/11 kV zone substation. The Bells Pond zone substation has dual 110/33/11 kV, 20/15/15 MVA and 40/20/30 MVA transformers feeding into two 11 kV switchboards. There are five 11 kV distribution feeders supplying the area around Bells Pond, with one dedicated to the Waihao Downs irrigation pump station.

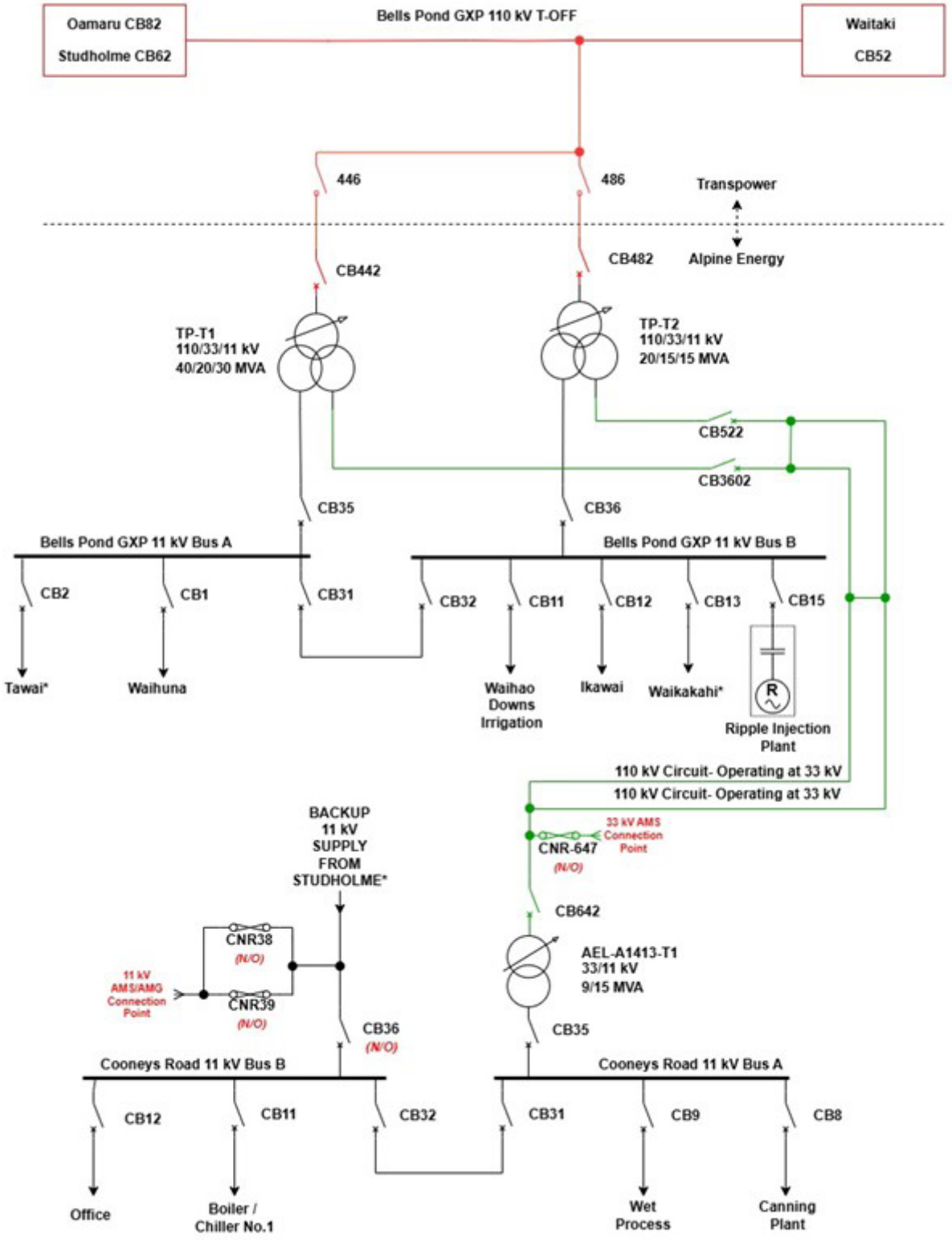
There is an 11 kV ripple injection plant located at the Bells Pond zone substation connected to the 11kV Bus B.

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. The zone substation is located immediately adjacent to the ODL dairy factory. The 11 kV from the power transformers at BPD GXP 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 ODL dairy factory, with one distribution feeder connected to an adjacent feeder from Studholme zone substation to provide backup supply up to 1 MVA (depend on feeder seasonal loading).

Figure below shows the overview of the region's network overview diagram.

# Bells Pond Region Network Overview




* Marked feeders interconnect with STU for backup supply

## Studholme GXP

Studholme GXP is supplied via the 110 kV transmission network from Timaru and Waitaki. The system is normally operated split at STU DS76 between May and September, with supply sourced from Waitaki during the dairy season. Outside this period, the switch is operated closed to enhance security of supply.

There are two 110/11 kV transformers (single phase banks) owned and operated by Transpower at Studholme GXP.

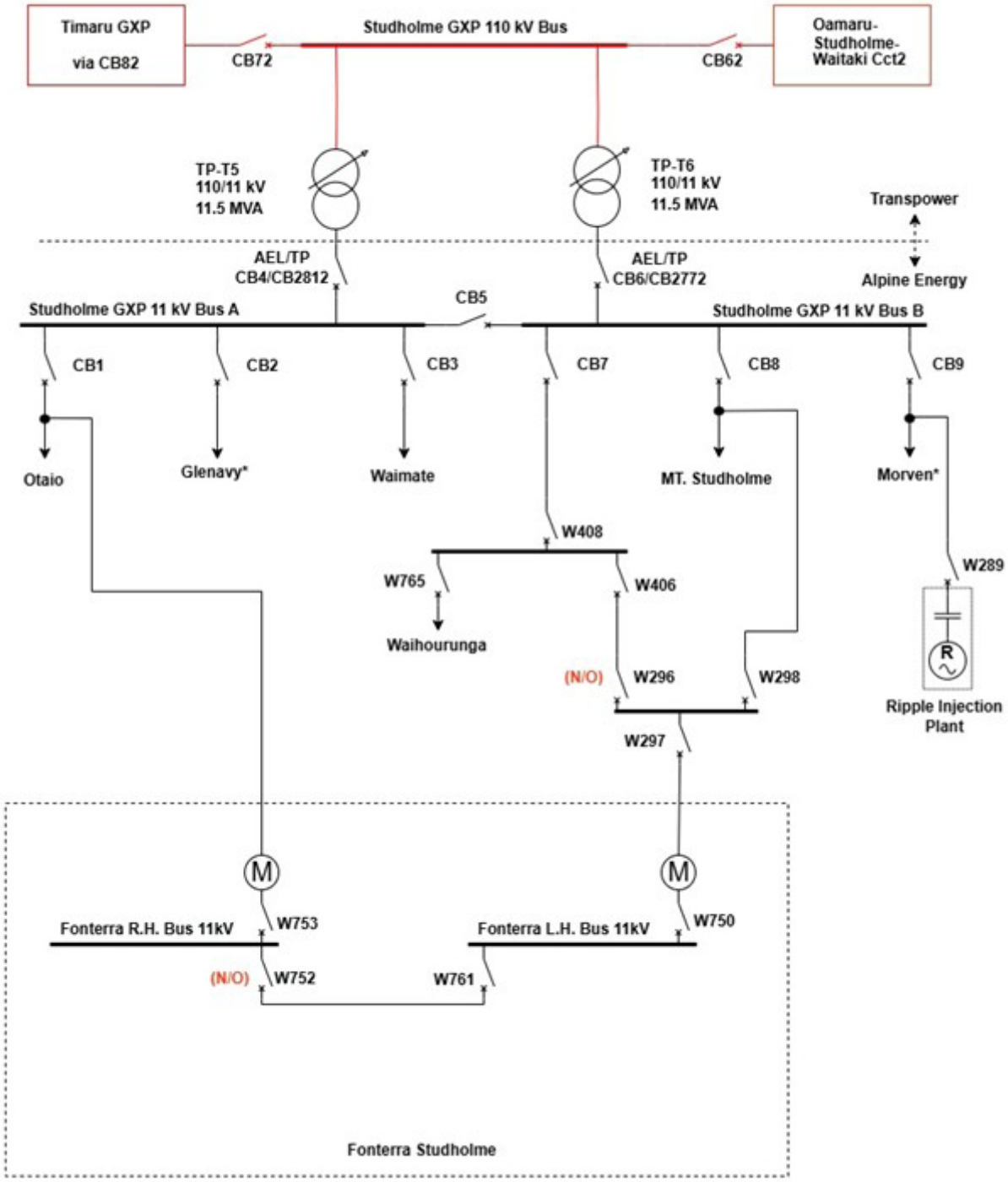
Alpine Energy take supply from Transpower at 11 kV. The 11 kV indoor switchgear has two incoming supplies, and six feeders supplying the nearby Fonterra Studholme dairy factory, the Waimate Township, and the surrounding rural area. The 11 kV switchboard and building is located on Transpower land.

The Fonterra Studholme dairy factory is supplied from three 11 kV distributions feeders (not dedicated) through a switching station (Hansen Street switching station) comprising of ring main units.

A ripple injection plant is connected to the Morven 11 kV distribution feeder which controls load within Studholme GXP network.

Figure below shows the network overview of the Studholme region.

# Studholme Region




* Marked feeders interconnect with BPD and CNR for backup supply

(M) - Metering Point

## Tekapō

Transpower (TP) operates an 11 kV switchboard that connects to the Genesis Energy TKA 28MW 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.

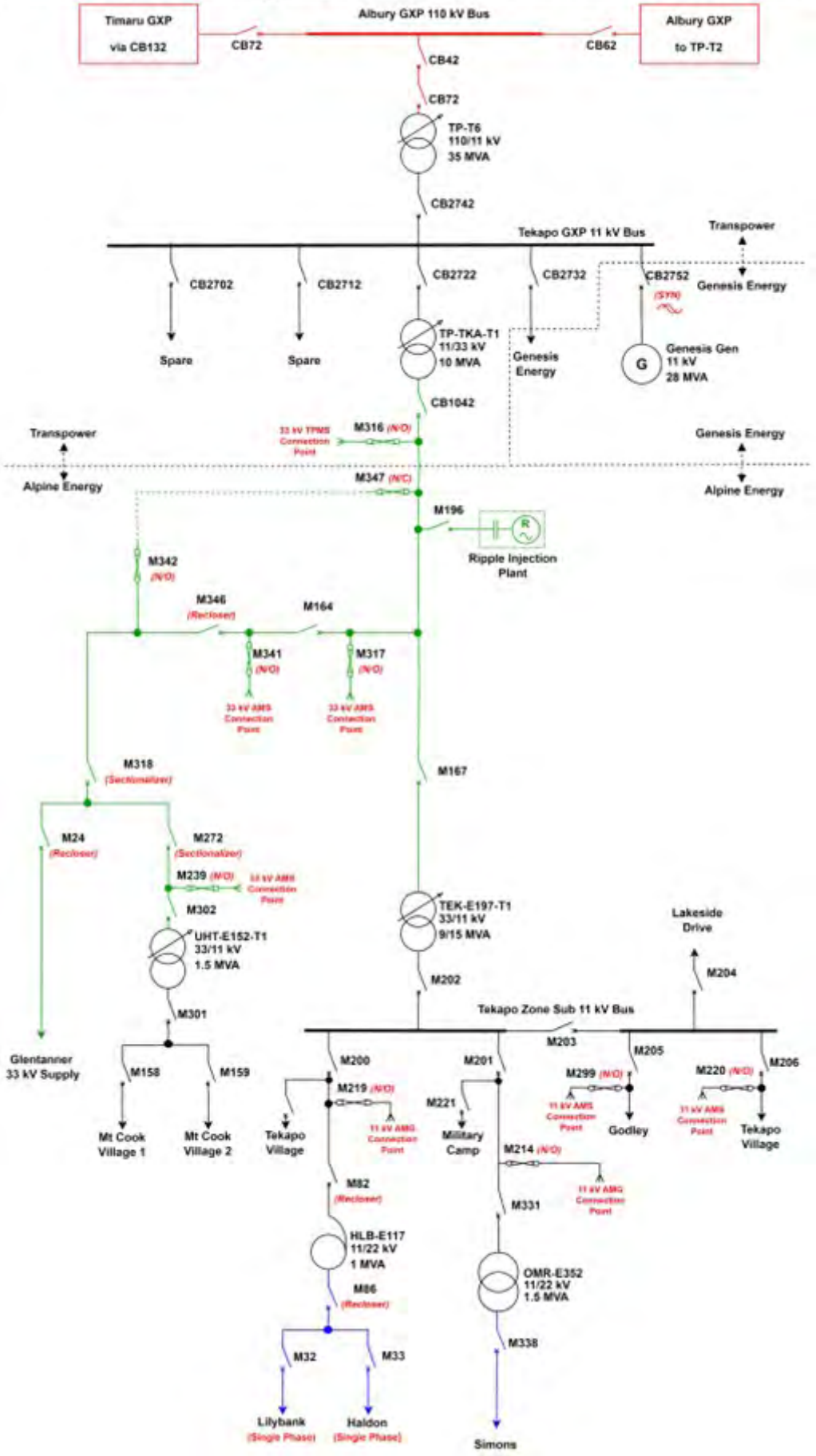
From the Tekapō GXP, we have a single 33 kV sub-transmission circuit to our 33/11 kV Tekapō zone substation (TEK – 9/15 MVA transformer). A 33 kV ripple plant is connected via a tap-off connection on the 33 kV sub-transmission circuit.

From TEK we have a 33 kV sub-transmission line to Unwin Hut. Along the sub-transmission line there are 33/0.415 kV distribution transformers supplying consumers. Unwin Hut is a small 33/11 kV zone substation (UHT) which supplies the Mt Cook Village via a 1.5 MVA transformer and two 11 kV distribution feeders.

TEK supplies the Tekapō township and surrounding rural areas with five 11 kV feeders.

Old Man Range (OMR – 1.5 MVA transformers) and Haldon–Lily bank (HLB – 1 MVA Auto transformer) are two zone substations fed off two of TEK's 11 kV distribution feeders, which act as step-up transformers 22/11 kV into the remote Haldon, Lily bank, and Simon's Pass areas. The 22 kV distribution past HLB is single phase.

# Tekapo Region Network Overview



## Temuka

The Temuka GXP is supplied by two 110 kV transmission lines from the Transpower Timaru substation.

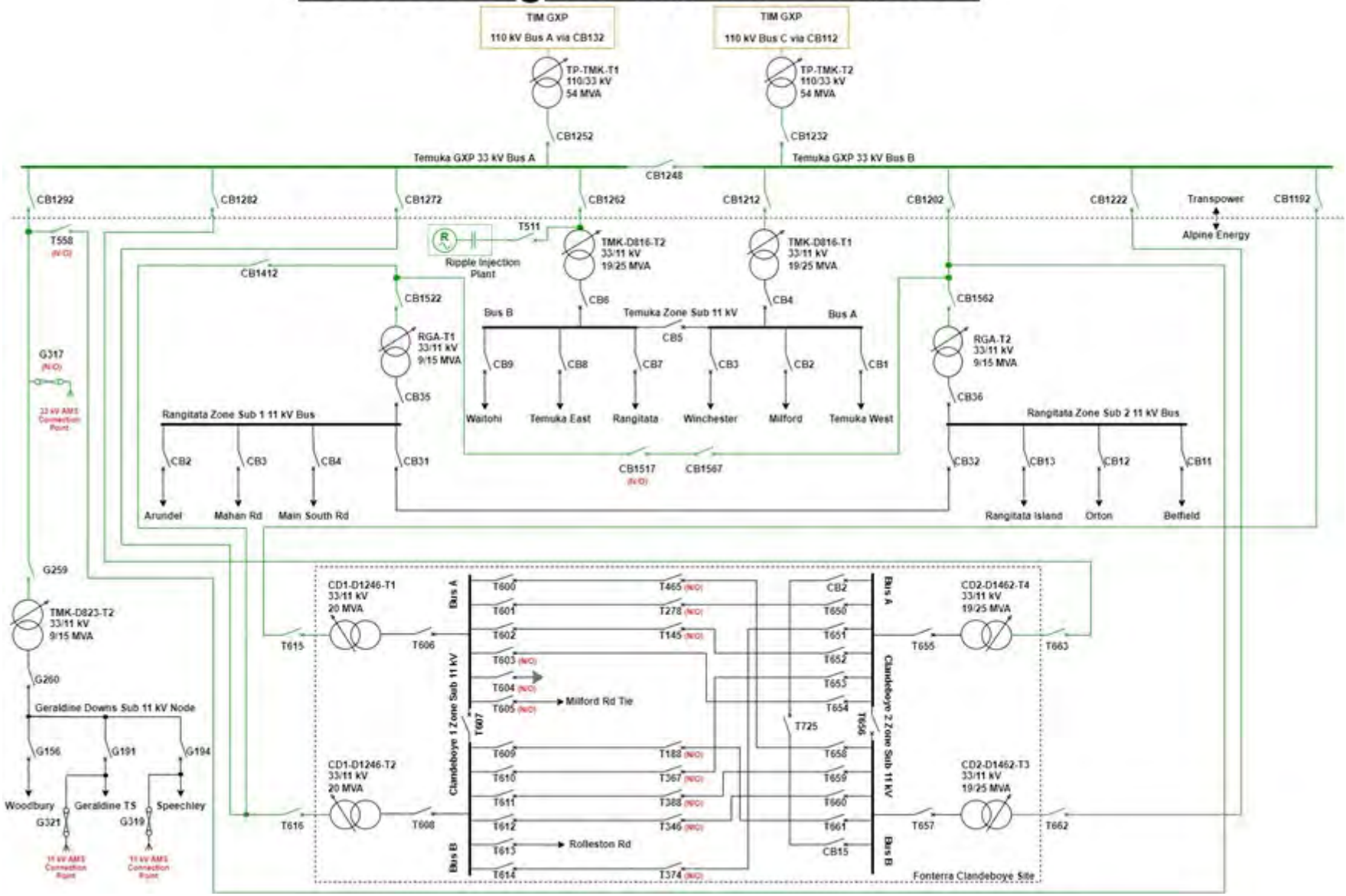
At the GXP, there are two 110/33 kV, 54 MVA power transformers which supply into a double switchboard.

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 overhead 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 nine and eleven 11 kV feeders, respectively, interconnected together for security of supply.
  - Factory distribution feeders are interconnected together for enhanced 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 two 9/15 MVA transformers with six 11 kV distribution feeders (11 kV busbar-tie is normally closed).
- One sub transmission feeder feeds the 33/11 kV Geraldine zone substation.
  - Consists of a single 15 MVA transformer with three 11 kV distribution feeders.

A 33 kV ripple injection plant is connected to one of the 33 kV sub transmission feeders that supply our Temuka zone substation.

# Temuka Region Network Overview



## Timaru GXP

The Timaru GXP is our largest supply point connecting two 220/110 kV interconnectors to a 110 kV bus, which acts as a transmission hub for Albury, Tekapo, Temuka, and Bells Pond/ Studholme. The 110 kV is stepped down through three 110/11 kV transformer banks to supply the Timaru GXP 11 kV switchboard (owned by Transpower). The 110/11 kV 47 MVA transformers are operated with two in service and one on hot standby. A ripple injection plant is connected to the 11 kV switchboard (bus C).

There are 24 feeders from the 11 kV Timaru switchboard which are split across three buses as follows:

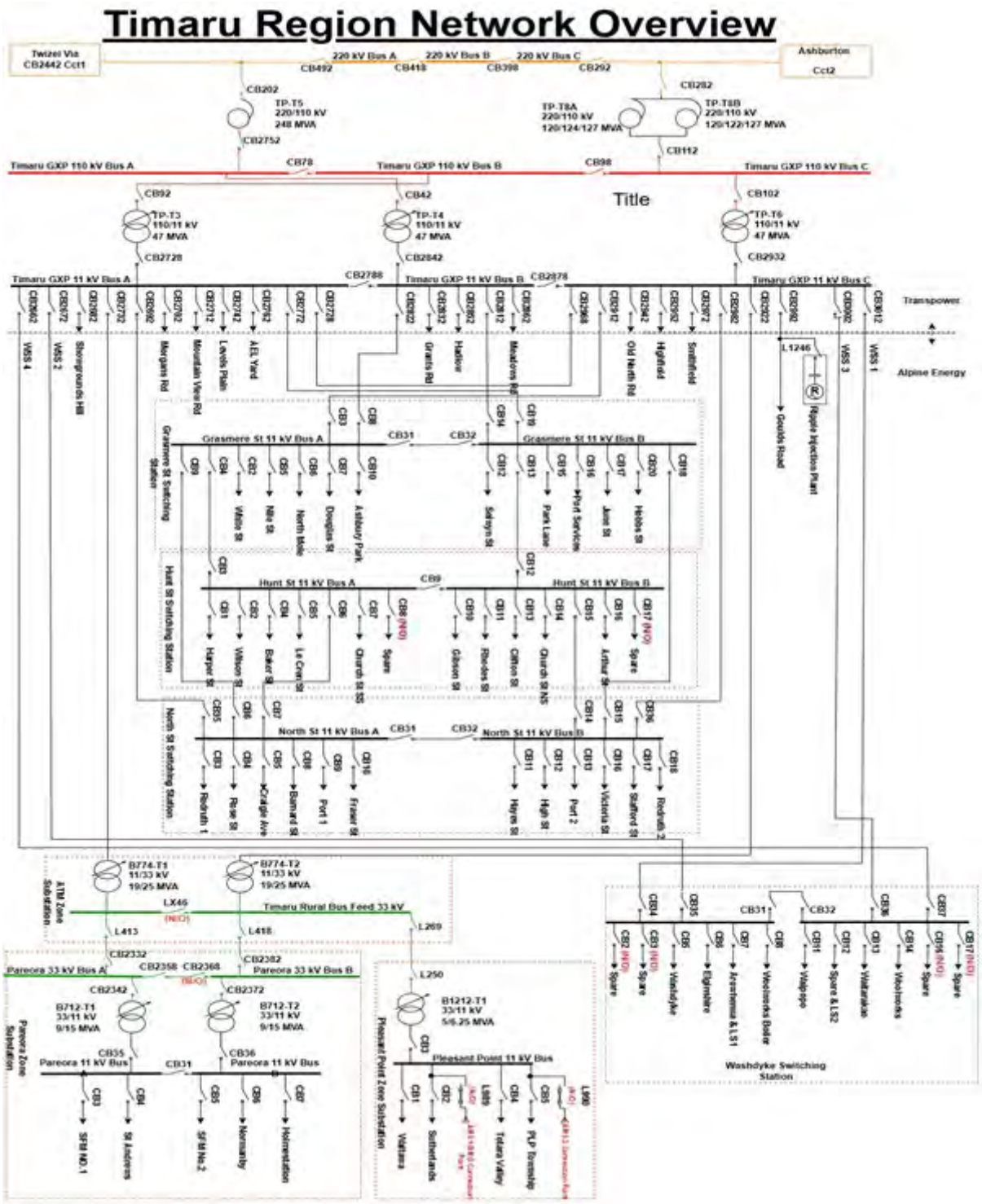
- Twelve of the feeders supply the western residential areas, northern residential areas, and industrial areas of Washdyke, and the meat-works at Smithfield.
- There are four 11 kV sub-transmission feeders to Grasmere switching station, which then split into a double circuit ring configuration to Hunt Street and North Street switching stations.
- Two 11 kV sub-transmission feeders connect directly to North Street switching station (cables rated at 33 kV).
- There are four 11 kV sub-transmission feeders supplying the Washdyke switching station (cables rated at 33 kV).
- 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.

Grasmere and Hunt Street Switching Stations have ten distribution feeders, while North Street and Washdyke have twelve. The Washdyke switching station feed seven 11 kV distribution feeders supplying the Washdyke/Seadown commercial and rural areas north of Timaru. Washdyke switching station has 5 spare circuit breakers and there is space to convert Washdyke switching station to a 33/11 kV zone station in the future.

The Pareora zone substation comprises of two 33/11 kV 9/15 MVA power transformers connected to an 11 kV bus from which five distribution feeders take supply providing power to the meat works and rural load at the south of Timaru. This is supplied from two sub transmission routes consisting of dedicated circuits that are fed from ATM. The first section of each circuit sits on a single pole structure with one circuit above the other. Each circuit then runs down into cable and back into OH line taking individual routes to Pareora Zone substation.

Pleasant Point zone substation consists of one 33/11 kV 5/6.25 MVA power transformer supplying an 11 kV bus with four distribution feeders supplying Pleasant Point township and outlying rural areas.

Figure below shows the Timaru region's network overview diagram.

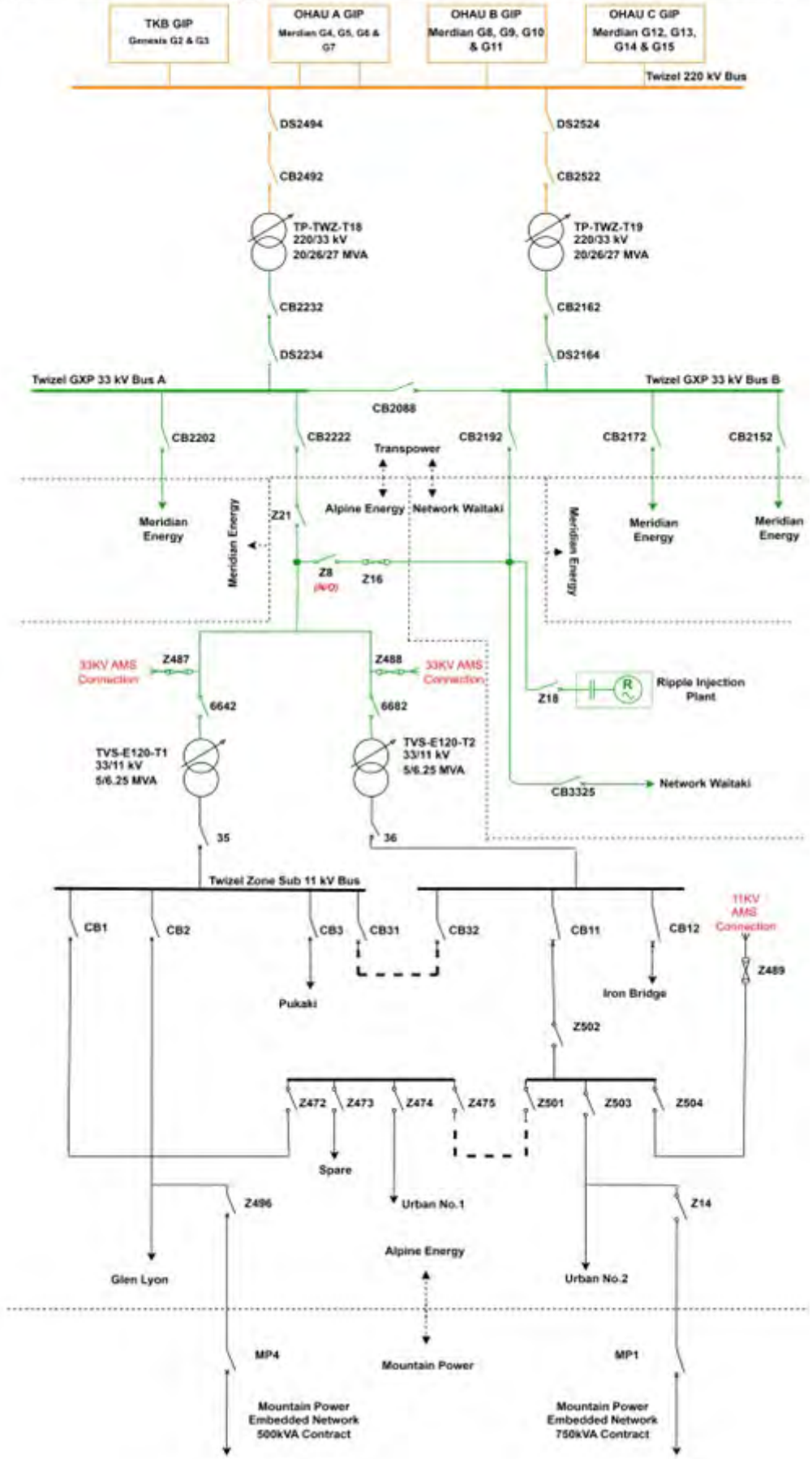

Timaru Region Network Overview
Twizel Via CB2442 Cct1
220 kV Bus A
220 kV Bus B
220 kV Bus C
CB492
CB418
CB398
CB292
Ashburton Cct2
CB202
TP-T5 220/110 kV 248 MVA
CB2752
CB282
TP-T8A 220/110 kV 120/124/127 MVA
TP-T8B 220/110 kV 120/122/127 MVA
CB1112
Timaru GXP 110 kV Bus A
CB78
Timaru GXP 110 kV Bus B
CB98
Timaru GXP 110 kV Bus C
Title
CB92
CB42
CB102
TP-T3 110/11 kV 47 MVA
TP-T4 110/11 kV 47 MVA
TP-T6 110/11 kV 47 MVA
CB2728
CB2842
CB2932
Timaru GXP 11 kV Bus A
CB2788
Timaru GXP 11 kV Bus B
CB2878
Timaru GXP 11 kV Bus C
Transpower
Alpine Energy
VBS 4
VBS 2
Showgrounds Hill
Morgans Rd
Mountain View Rd
Levels Rails
AEL Yard
Grants Rd
Hallow
Meadows Rd
Old North Rd
Highfield
Smithfield
L1246
Gooids Road
Ripple Injection Plant
VBS 3
VBS 1
Grasmere St Switching Station
Grasmere St 11 kV Bus A
CB31
CB32
Grasmere St 11 kV Bus B
Hunt St Switching Station
Hunt St 11 kV Bus A
CB89
Hunt St 11 kV Bus B
Harper St
Wilson St
Baker St
Le Cren St
Church St SS
Spare
Gibson St
Rhodes St
Clifton St
Church St NS
Arthur St
Spare
North St Switching Station
North St 11 kV Bus A
CB31
CB32
North St 11 kV Bus B
Redruth 1
Rose St
Craigie Ave
Bamard St
Port 1
Fraser St
Hayes St
High St
Port 2
Victoria St
Stafford St
Redruth 2
B774-T1 11/33 kV 19/25 MVA
B774-T2 11/33 kV 19/25 MVA
ATM Zone Substation
LX46 (NEO)
Timaru Rural Bus Feed 33 kV
L413
L418
L269
CB2332
CB2358
CB2368
CB2382
Pareora 33 kV Bus A
Pareora 33 kV Bus B
CB2342
CB2372
B712-T1 33/11 kV 9/15 MVA
B712-T2 33/11 kV 9/15 MVA
Pareora Zone Substation
CB35
Pareora 11 kV Bus
CB31
CB36
Pareora 11 kV Bus
SFM No.1
St Andrews
SFM No.2
Normanby
Holmestation
L250
B1212-T1 33/11 kV 5/6.25 MVA
Pleasant Point Zone Substation
Pleasant Point 11 kV Bus
Waitaoa
Sutherlands
Totara Valley
PLP Township
L98
CB31
CB32
Washdyke
Elginshire
Aviemore & LS1
Waitohi
Spare & LS2
Waitarakao
Woolcombs
Spare
Spare
Spare
Washdyke Switching Station

## Twizel

The Twizel GXP is supplied off the 220 kV Twizel bus and supplies Alpine Energy, Network Waitaki and Meridian Energy at 33 kV. We share the utilisation of one of the 220/33 kV transformers with Meridian Energy via the 33 kV bus A.

A single 33 kV sub-transmission line supplies our 33/11 kV Twizel township zone substation. At the substation, we have two 33/11 kV power transformers, with a capacity of 5/6.25. There is an indoor 11 kV switchboard with two distribution feeders supplying the Twizel township and three distribution feeders supplying the surrounding rural areas. 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 2026 – 31 March 2036

| 7<br>8 | for year ended | Current Year CY<br>31 Mar 26 | CY+1<br>31 Mar 27 | CY+2<br>31 Mar 28 | CY+3<br>31 Mar 29 | CY+4<br>31 Mar 30 | CY+5<br>31 Mar 31 | CY+6<br>31 Mar 32 | CY+7<br>31 Mar 33 | CY+8<br>31 Mar 34 | CY+9<br>31 Mar 35 | CY+10<br>31 Mar 36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | **11a(i): Expenditure on Assets Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | Consumer connection | 4,688 | 4,286 | 6,728 | 7,300 | 7,947 | 9,811 | 8,977 | 7,540 | 7,772 | 8,009 | 8,253 |
| 11 | System growth | 3,651 | 5,760 | 3,703 | 4,416 | 5,604 | 7,567 | 8,360 | 16,760 | 19,793 | 29,529 | 36,665 |
| 12 | Asset replacement and renewal | 16,628 | 21,266 | 17,414 | 16,591 | 18,994 | 33,310 | 28,268 | 27,070 | 18,970 | 18,712 | 20,580 |
| 13 | Asset relocations | 750 | 800 | 1,785 | - | - | - | - | - | - | - | - |
| 14 | Reliability, safety and environment: | | | | | | | | | | | |
| 15 | Quality of supply | 1,137 | 200 | 255 | 260 | 266 | 271 | 277 | 736 | 289 | 2,065 | 2,108 |
| 16 | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| 17 | Other reliability, safety and environment | 3,714 | 2,040 | 1,979 | 312 | 1,627 | 3,376 | 4,722 | 6,745 | 7,614 | 3,527 | 3,601 |
| 18 | **Total reliability, safety and environment** | **4,851** | **2,240** | **2,234** | **573** | **1,893** | **3,648** | **4,999** | **7,480** | **7,903** | **5,592** | **5,709** |
| 19 | **Expenditure on network assets** | **30,568** | **34,352** | **31,864** | **28,880** | **34,438** | **54,335** | **50,604** | **58,852** | **54,438** | **61,841** | **71,207** |
| 20 | Expenditure on non-network assets | 5,809 | 5,960 | 6,039 | 3,564 | 2,681 | 3,165 | 4,649 | 3,667 | 3,360 | 2,916 | 4,408 |
| 21 | **Expenditure on assets** | **36,378** | **40,312** | **37,903** | **32,443** | **37,119** | **57,499** | **55,253** | **62,519** | **57,798** | **64,758** | **75,616** |
| 22 | | | | | | | | | | | | |
| 23 | *plus* Cost of financing | | | | | | | | | | | |
| 24 | *less* Value of capital contributions | 3,636 | 4,256 | 5,382 | 5,840 | 6,358 | 7,849 | 7,182 | 6,032 | 6,217 | 6,407 | 6,603 |
| 25 | *plus* Value of vested assets | | | | | | | | | | | |
| 27 | **Capital expenditure forecast** | **32,742** | **36,056** | **32,521** | **26,603** | **30,761** | **49,651** | **48,071** | **56,486** | **51,581** | **58,350** | **69,013** |
| 29 | Assets commissioned | 29,468 | 32,450 | 29,269 | 23,943 | 27,685 | 44,686 | 43,264 | 50,838 | 46,423 | 52,515 | 62,112 |
| 32 | | **$000 (in constant prices)** | | | | | | | | | | |
| 33 | Consumer connection | 4,688 | 4,286 | 6,596 | 7,010 | 7,474 | 9,037 | 8,099 | 6,663 | 6,726 | 6,789 | 6,852 |
| 34 | System growth | 3,651 | 5,760 | 3,630 | 4,240 | 5,270 | 6,970 | 7,542 | 14,810 | 17,130 | 25,030 | 30,440 |
| 35 | Asset replacement and renewal | 16,628 | 21,266 | 17,073 | 15,931 | 17,864 | 30,683 | 25,503 | 23,920 | 16,418 | 15,861 | 17,086 |
| 36 | Asset relocations | 750 | 800 | 1,750 | - | - | - | - | - | - | - | - |
| 37 | Reliability, safety and environment: | | | | | | | | | | | |
| 38 | Quality of supply | 1,137 | 200 | 250 | 250 | 250 | 250 | 250 | 650 | 250 | 1,750 | 1,750 |
| 39 | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| 40 | Other reliability, safety and environment | 3,714 | 2,040 | 1,940 | 300 | 1,530 | 3,110 | 4,260 | 5,960 | 6,590 | 2,990 | 2,990 |
| 41 | **Total reliability, safety and environment** | **4,851** | **2,240** | **2,190** | **550** | **1,780** | **3,360** | **4,510** | **6,610** | **6,840** | **4,740** | **4,740** |
| 42 | **Expenditure on network assets** | **30,568** | **34,352** | **31,239** | **27,731** | **32,388** | **50,050** | **45,654** | **52,003** | **47,114** | **52,420** | **59,118** |
| 43 | **Expenditure on non-network assets** | 5,809 | 5,960 | 5,921 | 3,422 | 2,522 | 2,915 | 4,194 | 3,240 | 2,908 | 2,472 | 3,660 |
| 44 | **Expenditure on assets** | **36,378** | **40,312** | **37,160** | **31,153** | **34,909** | **52,965** | **49,848** | **55,243** | **50,022** | **54,892** | **62,778** |
| 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 | 800 | 1,750 | | | | | | | | |
| 49 | Research and development | - | | | | | | | | | | |
| 50 | Cybersecurity (Commission only) | 465 | | | | | | | | | | |

## Schedule 11a. Report on forecast capital expenditure continued

| 53<br>54 | for year ended | Current Year CY<br>31 Mar 26 | CY+1<br>31 Mar 27 | CY+2<br>31 Mar 28 | CY+3<br>31 Mar 29 | CY+4<br>31 Mar 30 | CY+5<br>31 Mar 31 | CY+6<br>31 Mar 32 | CY+7<br>31 Mar 33 | CY+8<br>31 Mar 34 | CY+9<br>31 Mar 35 | CY+10<br>31 Mar 36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 55 | **Difference between nominal and constant price forecasts** | **$000** | | | | | | | | | | |
| 56 | Consumer connection | - | - | 132 | 290 | 473 | 774 | 878 | 877 | 1,046 | 1,220 | 1,401 |
| 57 | System growth | - | - | 73 | 176 | 334 | 597 | 818 | 1,950 | 2,663 | 4,499 | 6,225 |
| 58 | Asset replacement and renewal | - | - | 341 | 660 | 1,131 | 2,627 | 2,765 | 3,150 | 2,552 | 2,851 | 3,494 |
| 59 | Asset relocations | - | - | 35 | - | - | - | - | - | - | - | - |
| 60 | Reliability, safety and environment: | | | | | | | | | | | |
| 61 | Quality of supply | - | - | 5 | 10 | 16 | 21 | 27 | 86 | 39 | 315 | 358 |
| 62 | Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| 63 | Other reliability, safety and environment | - | - | 39 | 12 | 97 | 266 | 462 | 785 | 1,024 | 537 | 611 |
| 64 | **Total reliability, safety and environment** | **-** | **-** | **39** | **12** | **97** | **266** | **462** | **785** | **1,024** | **537** | **611** |
| 65 | **Expenditure on network assets** | **-** | | **615** | **1,150** | **1,942** | **4,174** | **3,971** | **6,673** | **7,045** | **9,069** | **10,455** |
| 66 | Expenditure on non-network assets | - | - | 118 | 142 | 160 | 250 | 455 | 427 | 452 | 444 | 748 |
| 67 | **Expenditure on assets** | **-** | **-** | **743** | **1,301** | **2,097** | **4,426** | **4,333** | **7,104** | **7,472** | **9,519** | **11,120** |

## Schedule 11a. Report on forecast capital expenditure continued

| 73 | for year ended | Current Year CY 31 Mar 26 | CY+1 31 Mar 27 | CY+2 31 Mar 28 | CY+3 31 Mar 29 | CY+4 31 Mar 30 | CY+5 31 Mar 31 |
|---|---|---|---|---|---|---|---|
| 74 | **11a(ii): Consumer Connection** | | | | | | |
| 75 | *Consumer types defined by EDB** | **$000 (in constant prices)** | | | | | |
| 76 | Large Industrial | 1,120 | 80 | 134 | 135 | 136 | 138 |
| | Commercial | 640 | 2,019 | 3,384 | 3,418 | 3,452 | 3,485 |
| | Subdivision | 800 | 715 | 1,198 | 1,210 | 1,222 | 1,234 |
| | Irrigation | 200 | 259 | 434 | 439 | 443 | 447 |
| 77 | Residential | 720 | 705 | 1,182 | 1,194 | 1,206 | 1,218 |
| 78 | Large Distributed Generation | 1,200 | 500 | 250 | - | 1,000 | 1,000 |
| 79 | HV Alterations | - | - | - | 600 | - | 1,500 |
| 80 | LV Alterations | 8 | 8 | 14 | 14 | 15 | 15 |
| 81 | *include additional rows if needed | | | | | | |
| 82 | **Consumer connection expenditure** | **4,688** | **4,286** | **6,596** | **7,010** | **7,474** | **9,037** |
| 83 | *less* Capital contributions funding consumer connection | 3,750 | 3,429 | 5,277 | 5,608 | 5,979 | 7,230 |
| 84 | **Consumer connection less capital contributions** | **938** | **857** | **1,319** | **1,402** | **1,495** | **1,807** |
| 85 | **11a(iii): System Growth** | | | | | | |
| 86 | Subtransmission | - | - | - | - | - | 1,700 |
| 87 | Zone substations | 30 | 30 | 50 | 220 | 200 | 500 |
| 88 | Distribution and LV lines | 400 | 560 | 1,480 | 1,370 | 300 | - |
| 89 | Distribution and LV cables | 2,049 | 2,820 | 1,050 | 2,000 | 4,120 | 2,520 |
| 90 | Distribution substations and transformers | 472 | 930 | 400 | - | - | 350 |
| 91 | Distribution switchgear | - | 420 | - | - | - | 950 |
| 92 | Other network assets | 700 | 1,000 | 650 | 650 | 650 | 950 |
| 93 | **System growth expenditure** | **3,651** | **5,760** | **3,630** | **4,240** | **5,270** | **6,970** |
| 94 | less Capital contributions funding system growth | | | | | | |
| 95 | **System growth less capital contributions** | **3,651** | **5,760** | **3,630** | **4,240** | **5,270** | **6,970** |
| | | | | | | | |
| 99 | **11a(iv): Asset Replacement and Renewal** | **$000 (in constant prices)** | | | | | |
| 100 | Subtransmission | - | - | - | - | - | - |
| 101 | Zone substations | 243 | 198 | 228 | 138 | 30 | 1,530 |
| 102 | Distribution and LV lines | 4,568 | 4,606 | 1,500 | 1,500 | 2,000 | 3,400 |
| 103 | Distribution and LV cables | 634 | 1,398 | 3,420 | 3,820 | 3,920 | 2,240 |
| 104 | Distribution substations and transformers | 9,193 | 12,404 | 10,550 | 9,778 | 11,459 | 22,193 |
| 105 | Distribution switchgear | 1,489 | 2,660 | 1,375 | 695 | 455 | 1,320 |
| 106 | Other network assets | 500 | - | - | - | - | - |
| 107 | **Asset replacement and renewal expenditure** | **16,628** | **21,266** | **17,073** | **15,931** | **17,864** | **30,683** |
| 108 | *less* Capital contributions funding asset replacement and renewal | | | | | | |
| 109 | **Asset replacement and renewal less capital contributions** | **16,628** | **21,266** | **17,073** | **15,931** | **17,864** | **30,683** |

## Schedule 11a. Report on forecast capital expenditure continued

| 111<br>112 | for year ended | Current Year CY<br>31 Mar 26 | CY+1<br>31 Mar 27 | CY+2<br>31 Mar 28 | CY+3<br>31 Mar 29 | CY+4<br>31 Mar 30 | CY+5<br>31 Mar 31 |
|---|---|---|---|---|---|---|---|
| 113 | **11a(v): Asset Relocations** | **$000 (in constant prices)** | | | | | |
| 114 | *Project or programme** | | | | | | |
| 115 | Distribution Cable | 750 | 800 | 1,750 | - | - | - |
| 116 | | | | | | | |
| 117 | | | | | | | |
| 118 | | | | | | | |
| 119 | | | | | | | |
| 120 | **include additional rows if needed* | | | | | | |
| 121 | All other project or programmes - asset relocations | | | | | | |
| 122 | **Asset relocations expenditure** | **750** | **800** | **1,750** | **-** | **-** | **-** |
| 123 | *less* Capital contributions funding asset relocations | | | | | | |
| 124 | **Asset relocations less capital contributions** | **750** | **800** | **1,750** | **-** | **-** | **-** |
| 128 | **11a(vi): Quality of Supply** | | | | | | |
| 129 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 130 | Communication | 100 | 50 | 100 | 100 | 100 | 100 |
| 131 | Distribution Systems | 195 | - | - | - | - | - |
| 132 | Ferro-Resonance | 70 | 150 | 150 | 150 | 150 | 150 |
| 133 | Load and Voltage Control | 772 | - | - | - | - | - |
| 134 | | - | - | - | - | - | - |
| 135 | **include additional rows if needed* | | | | | | |
| 136 | All other projects or programmes - quality of supply | | | | | | |
| 137 | **Quality of supply expenditure** | **1,137** | **200** | **250** | **250** | **250** | **250** |
| 138 | *less* Capital contributions funding quality of supply | | | | | | |
| 139 | **Quality of supply less capital contributions** | **1,137** | **200** | **250** | **250** | **250** | **250** |
| 143 | **11a(vii): Legislative and Regulatory** | | | | | | |
| 144 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 145 | | | | | | | |
| 146 | | | | | | | |
| 147 | | | | | | | |
| 148 | | | | | | | |
| 149 | | | | | | | |
| 150 | **include additional rows if needed* | | | | | | |
| 151 | All other projects or programmes - legislative and regulatory | | | | | | |
| 152 | **Legislative and regulatory expenditure** | - | - | - | - | - | - |
| 153 | less Capital contributions funding legislative and regulatory | | | | | | |
| 154 | **Legislative and regulatory less capital contributions** | - | - | - | - | - | - |

## Schedule 11a. Report on forecast capital expenditure continued

| 156 | for year ended | Current Year CY 31 Mar 26 | CY+1 31 Mar 27 | CY+2 31 Mar 28 | CY+3 31 Mar 29 | CY+4 31 Mar 30 | CY+5 31 Mar 31 |
|---|---|---|---|---|---|---|---|
| 157 | **11a(viii): Other Reliability, Safety and Environment** | | | | | | |
| 158 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 159 | Communication | 170 | 170 | 170 | - | - | - |
| | Distribution Cable | 12 | - | - | - | 500 | 350 |
| | Distribution Line | 100 | 400 | - | - | 50 | 50 |
| | Distribution Substations | 580 | - | - | - | 200 | - |
| | Distribution Switchgear | 806 | 300 | - | - | - | 50 |
| | Load Control | - | 100 | 1,400 | 100 | 480 | 1,750 |
| | Protection | 650 | 610 | 120 | - | - | - |
| | SCADA and Communications | 36 | 150 | 150 | 200 | 300 | 500 |
| | Substation | - | - | 100 | - | - | 20 |
| 160 | Subtransmission Cable | - | 100 | - | - | - | - |
| 161 | Subtransmission Line | - | 210 | - | - | - | - |
| 162 | Switchgear | 1,000 | - | - | - | - | 390 |
| 163 | Zone Substation Transformer | 360 | - | - | - | - | - |
| 164 | **include additional rows if needed* | | | | | | |
| 165 | All other projects or programmes - other reliability, safety and environment | | | | | | |
| 166 | **Other reliability, safety and environment expenditure** | **3,714** | **2,040** | **1,940** | **300** | **1,530** | **3,110** |
| 167 | *less* Capital contributions funding other reliability, safety and environment | | | | | | |
| 168 | **Other reliability, safety and environment less capital contributions** | **3,714** | **2,040** | **1,940** | **300** | **1,530** | **3,110** |

## Schedule 11a. Report on forecast capital expenditure continued

| 171 | for year ended | Current Year CY 31 Mar 26 | CY+1 31 Mar 27 | CY+2 31 Mar 28 | CY+3 31 Mar 29 | CY+4 31 Mar 30 | CY+5 31 Mar 31 |
|---|---|---|---|---|---|---|---|
| 172 | **11a(ix): Non-Network Assets** | | | | | | |
| 173 | **Routine expenditure** | | | | | | |
| 174 | *Project or programme** | **$000 (in constant prices)** | | | | | |
| 175 | Fleet | 3,494 | 2,145 | 2,145 | 1,505 | 350 | 855 |
| 176 | Digital | 496 | 300 | 180 | 300 | 534 | 400 |
| 177 | Property | 1,100 | 2,620 | 2,500 | 500 | 500 | 500 |
| 178 | Plant and Equipment | 620 | 895 | 1,096 | 1,117 | 1,138 | 1,160 |
| 179 | Cyber security | | - | - | - | - | - |
| 180 | *include additional rows if needed | | | | | | |
| 181 | All other projects or programmes - routine expenditure | | | | | | |
| 182 | **Routine expenditure** | **5,709** | **5,960** | **5,921** | **3,422** | **2,522** | **2,915** |
| 183 | **Atypical expenditure** | | | | | | |
| 184 | *Project or programme** | | | | | | |
| 185 | Transformer Bund | 100 | | | | | |
| 186 | Property | | | | | | |
| 187 | Branding | | | | | | |
| 188 | | | | | | | |
| 189 | | | | | | | |
| 190 | *include additional rows if needed | | | | | | |
| 191 | All other projects or programmes - atypical expenditure | | | | | | |
| 192 | **Atypical expenditure** | **100** | **-** | **-** | **-** | **-** | **-** |
| 193 | | | | | | | |
| 194 | **Expenditure on non-network assets** | **5,809** | **5,960** | **5,921** | **3,422** | **2,522** | **2,915** |

## Schedule 11b. Report on forecast operational expenditure

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

| 7<br>8 | for year ended | Current Year CY 31 Mar 26 | CY+1 31 Mar 27 | CY+2 31 Mar 28 | CY+3 31 Mar 29 | CY+4 31 Mar 30 | CY+5 31 Mar 31 | CY+6 31 Mar 32 | CY+7 31 Mar 33 | CY+8 31 Mar 34 | CY+9 31 Mar 35 | CY+10 31 Mar 36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | **Operational Expenditure Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | Service interruptions and emergencies | 2,434 | 2,196 | 2,240 | 2,317 | 2,397 | 2,480 | 2,565 | 2,654 | 2,745 | 2,840 | 2,938 |
| 11 | Vegetation management | 1,053 | 1,100 | 1,122 | 1,146 | 1,170 | 1,194 | 1,219 | 1,245 | 1,271 | 1,298 | 1,325 |
| 12 | Routine and corrective maintenance and inspection | 3,276 | 4,100 | 4,182 | 4,270 | 4,359 | 4,451 | 4,545 | 4,640 | 4,737 | 4,837 | 4,938 |
| 13 | Asset replacement and renewal | 27 | 50 | 51 | 52 | 53 | 54 | 55 | 57 | 58 | 59 | 60 |
| 14 | **Network Opex** | **6,789** | **7,446** | **7,595** | **7,785** | **7,979** | **8,179** | **8,384** | **8,595** | **8,812** | **9,033** | **9,261** |
| 15 | System operations and network support | 4,203 | 6,141 | 5,366 | 5,240 | 5,350 | 5,469 | 5,590 | 5,701 | 5,820 | 5,935 | 6,067 |
| 16 | Business support | 20,903 | 24,778 | 26,863 | 21,645 | 22,104 | 21,250 | 21,705 | 22,160 | 22,629 | 23,103 | 23,597 |
| 17 | Non-network solutions provided by a related party or third party | | | | | | | | | | | |
| 18 | **Non-network opex** | **25,106** | **30,918** | **32,230** | **26,885** | **27,454** | **26,719** | **27,295** | **27,861** | **28,449** | **29,039** | **29,664** |
| 19 | **Operational expenditure** | **31,896** | **38,364** | **39,825** | **34,670** | **35,433** | **34,898** | **35,679** | **36,456** | **37,261** | **38,072** | **38,926** |
| 22 | | **$000 (in constant prices)** | | | | | | | | | | |
| 23 | Service interruptions and emergencies | 2,434 | 2,196 | 2,196 | 2,225 | 2,254 | 2,284 | 2,314 | 2,345 | 2,376 | 2,407 | 2,439 |
| 24 | Vegetation management | 1,053 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 | 1,100 |
| 25 | Routine and corrective maintenance and inspection | 3,276 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 | 4,100 |
| 26 | Asset replacement and renewal | 27 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| 27 | **Network Opex** | **6,789** | **7,446** | **7,446** | **7,475** | **7,504** | **7,534** | **7,564** | **7,595** | **7,626** | **7,657** | **7,689** |
| 28 | System operations and network support | 4,203 | 6,141 | 5,261 | 5,031 | 5,031 | 5,037 | 5,043 | 5,037 | 5,037 | 5,031 | 5,037 |
| 29 | Business support | 20,903 | 24,778 | 26,337 | 20,784 | 20,788 | 19,574 | 19,582 | 19,581 | 19,584 | 19,584 | 19,591 |
| 30 | Non-network solutions provided by a related party or third party | | | | | | | | | | | |
| 31 | **Non-network opex** | **25,106** | **30,918** | **31,598** | **25,816** | **25,820** | **24,612** | **24,625** | **24,618** | **24,622** | **24,615** | **24,628** |
| 32 | **Operational expenditure** | **31,896** | **38,364** | **39,044** | **33,291** | **33,324** | **32,146** | **32,189** | **32,213** | **32,248** | **32,272** | **32,317** |
| 33 | **Subcomponents of operational expenditure (where known)**<br>**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)* | | | | | | | | | | | |
| 36 | Energy efficiency and demand side management, reduction of energy losses | | | | | | | | | | | |
| 37 | Direct billing* | | | | | | | | | | | |
| 38 | Research and Development | | | | | | | | | | | |
| 39 | Insurance | 612 | 753 | 778 | 795 | 811 | 828 | 846 | 864 | 882 | 900 | 919 |
| | Cybersecurity (Commission only) | 574 | 623 | 685 | 685 | 685 | 685 | 686 | 686 | 686 | 686 | 686 |
| 41 | ** Direct billing expenditure by suppliers that direct bill the majority of their consumers* | | | | | | | | | | | |
| 45 | **Difference between nominal and real forecasts** | **$000** | | | | | | | | | | |
| 46 | Service interruptions and emergencies | - | - | 44 | 92 | 143 | 196 | 251 | 309 | 369 | 433 | 499 |
| 47 | Vegetation management | - | - | 22 | 46 | 70 | 94 | 119 | 145 | 171 | 198 | 225 |
| 48 | Routine and corrective maintenance and inspection | - | - | 82 | 170 | 259 | 351 | 445 | 540 | 637 | 737 | 838 |
| 49 | Asset replacement and renewal | - | - | 1 | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 10 |
| 50 | **Network Opex** | **-** | **-** | **149** | **310** | **475** | **645** | **820** | **1,000** | **1,186** | **1,376** | **1,572** |
| 51 | System operations and network support | - | - | 105 | 208 | 318 | 431 | 547 | 663 | 783 | 904 | 1,030 |
| 52 | Business support | - | - | 527 | 861 | 1,316 | 1,676 | 2,123 | 2,579 | 3,045 | 3,520 | 4,006 |
| 53 | Non-network solutions provided by a related party or third party | - | - | - | - | - | - | - | - | - | - | - |
| 54 | **Non-network opex** | **-** | **-** | **632** | **1,069** | **1,634** | **2,107** | **2,670** | **3,242** | **3,828** | **4,424** | **5,036** |
| 55 | **Operational expenditure** | **-** | **-** | **781** | **1,379** | **2,109** | **2,752** | **3,490** | **4,242** | **5,013** | **5,800** | **6,609** |

## Schedule 12a: Report on asset condition

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

| 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. | - | 0.06% | 31.83% | 33.08% | 35.03% | | 3 | 1.10% |
| 11 | All | Overhead Line | Wood poles | No. | 16.55% | 8.99% | 7.52% | 22.15% | 44.79% | | 3 | 1.50% |
| 12 | All | Overhead Line | Other pole types | No. | - | - | - | - | - | | N/A | |
| 13 | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | - | 16.32% | 18.18% | 36.90% | 28.60% | | 3 | - |
| 14 | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | - | - | - | - | - | | N/A | |
| 15 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | - | 0.12% | 0.31% | 6.52% | 93.05% | | 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 | - | - | 2.13% | 83.27% | 14.61% | | 3 | - |
| 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. | 5.81% | 9.30% | 23.26% | 10.47% | 51.16% | | 4 | - |
| 28 | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | 21.57% | 15.69% | 19.61% | 1.96% | 41.18% | | 3 | - |
| 29 | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | 4.27% | 6.84% | 16.24% | 5.98% | 66.67% | | 3 | 5.00% |
| 30 | HV | Zone substation switchgear | 33kV RMU | No. | - | - | - | - | - | | N/A | - |
| 31 | HV | Zone substation switchgear | 50/66/110kV CB (Indoor) | No. | - | - | - | - | - | | | |
| 32 | HV | Zone substation switchgear | 50/66/110kV CB (Outdoor) | No. | - | - | - | 50.00% | 50.00% | | 4 | - |
| 33 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (ground mounted) | No. | 3.76% | - | 11.27% | 25.82% | 59.15% | | 3 | - |
| 34 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | - | - | - | 6.78% | 93.22% | | 3 | - |
| 35 | | | | | | | | | | | | |

## Schedule 12a: Report on asset condition continued

| 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. | - | 11.11% | 3.70% | 22.22% | 62.96% | | 3 | 4.00% |
| 40 | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 2.57% | 41.17% | 17.59% | 15.89% | 22.80% | | 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% | 0.95% | 1.09% | 15.16% | 82.52% | | 3 | 0.50% |
| 44 | HV | Distribution Cable | Distribution UG PILC | km | - | - | 2.20% | 82.73% | 15.06% | | 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. | - | - | 11.43% | 45.71% | 42.86% | | 3 | 5.70% |
| 47 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | 4.85% | - | 14.55% | 33.33% | 47.27% | | 3 | - |
| 48 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | 15.48% | 5.35% | 5.38% | 25.82% | 47.96% | | 3 | 5.00% |
| 49 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | 1.41% | 2.82% | 1.41% | 2.82% | 91.55% | | 3 | - |
| 50 | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | 3.73% | 14.32% | 25.73% | 12.45% | 43.78% | | 3 | 2.00% |
| 51 | HV | Distribution Transformer | Pole Mounted Transformer | No. | 1.37% | 30.35% | 30.11% | 24.03% | 14.15% | | 3 | 1.00% |
| 52 | HV | Distribution Transformer | Ground Mounted Transformer | No. | 0.54% | 17.25% | 24.31% | 32.44% | 25.47% | | 3 | 1.00% |
| 53 | HV | Distribution Transformer | Voltage regulators | No. | - | - | - | 67.65% | 32.35% | | 4 | - |
| 54 | HV | Distribution Substations | Ground Mounted Substation Housing | No. | | | | | | | N/A | |
| 55 | LV | LV Line | LV OH Conductor | km | 0.37% | 13.19% | 60.55% | 21.50% | 4.39% | | 3 | 2.00% |
| 56 | LV | LV Cable | LV UG Cable | km | 0.26% | 0.57% | 6.80% | 58.42% | 33.95% | | 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. | 2.00% | 3.12% | 13.59% | 71.94% | 9.35% | | 3 | 3.10% |
| 60 | All | SCADA and communications | SCADA and communications equipment operating as a single system | Lot | 1.95% | 0.28% | 23.68% | 28.13% | 45.96% | | 3 | 5.00% |
| 61 | All | Capacitor Banks | Capacitors including controls | No. | - | 21.43% | - | 32.14% | 46.43% | | 3 | - |
| 62 | All | Load Control | Centralised plant | Lot | 2.04% | - | 40.82% | 36.73% | 20.41% | | 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

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

**12b(i): System Growth - Zone Substations**

| Existing Zone Substations | Current peak load (MVA) | Current peak load period | Installed operating capacity (MVA) | Current security of supply classification (type) | Current constraint type | Current available capacity (MVA) | Peak load period +5 yrs | Available capacity +5 yrs (MVA) | Security of supply classification +5 yrs (type) | Peak load period +10 yrs | Min. available capacity +10 yrs (MVA) | Max. available capacity +10 yrs (MVA) | Security of supply classification +10 yrs (type) | Forecast constraint type | Year of any forecast constraint | Constraint primary cause | Constraint solution type | Constraint solution progress | Temporary constraint solution remaining lifespan | Explanation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Albury (ABY) | 3.54 | Winter | 6.92 | N | No constraint | 3.38 | Winter | 3.11 | N | Winter | 2.00 | 2.64 | N | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Old Man Range (OMR) | 0.40 | Summer | 1.40 | N | No constraint | 1.00 | Summer | 0.96 | N | Summer | 0.89 | 0.91 | N | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Bells Pond (BPD) | 15.24 | Summer | 20.00 | N-1 | No constraint | 4.76 | Summer | 7.65 | N-1 | Summer | 6.52 | 6.78 | N-1 | Security | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Clandeboye 1 (CD1) | 14.23 | Summer | 20.00 | N-1 | No constraint | 5.77 | Summer | 3.94 | N | Summer | 3.85 | 3.89 | N | Capacity | 2 | Zone substation transformer | Network upgrade | Planning stage | Not applicable | Meets Alpine security standard |
| Clandeboye 2 (CD2) | 20.90 | Spring | 23.69 | N-1 | No constraint | 2.79 | Summer | 15.68 | N | Summer | 0.00 | 15.68 | N | Capacity | 3 | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | New decarbonization loads at Fonterra Clandeboye will be supplied from a new GXP in Orari or alternatively by upgrading Temuka GXP and transmission assets, and by building a new third zone subsation at Fonterra Clandeboye |
| Cooney's Road (CNR) | 4.83 | Autumn | 15.00 | N | No constraint | 10.17 | Summer | 8.53 | N | Summer | 6.37 | 7.01 | N | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Fairlie (FLE) | 3.56 | Winter | 6.25 | N | No constraint | 2.69 | Winter | 2.29 | N | Winter | 1.19 | 1.74 | N | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Geraldine (GLD) | 7.76 | Winter | 12.06 | N | Security | 4.30 | Winter | 3.48 | N | Winter | 0.97 | 2.45 | N | Security | 1 | Distribution back-up circuit capacity | Network upgrade | No active planning | Not applicable | Upgrade/ develop back-up HV distribution feeder ties are being explored |
| Haldon Lilybank (HLB) | 0.48 | Winter | 0.66 | N | No constraint | 0.18 | Winter | 0.06 | N | Winter | -0.12 | -0.08 | N | Capacity | 7 | Ancillary equipment | Undecided | No active planning | Not applicable | Meets Alpine security standard up to +5 years, Constraint asset upgrades beyond 5 years |
| Pareora (PAR) | 9.33 | Summer | 10.80 | N-1 | No constraint | 1.47 | Summer | 12.85 | N | Summer | 11.87 | 12.25 | N | Security | 7 | Subtransmission circuit | Demand response | No active planning | Not applicable | Installed transformer capacity 2x15 MVA and incomer capacity 2x11 MVA. Demand flexibility and non-network options are being explored |
| Pleasant Point (PLP) | 5.25 | Summer | 6.25 | N | No constraint | 1.00 | Summer | 5.63 | N | Summer | 0.00 | 0.16 | N | Capacity | 9 | Zone substation transformer | Network upgrade | No active planning | Not applicable | Zone substation transformer and incomer upgrades to 2x15 MVA |
| Rangitata (RGA) | 10.52 | Summer | 20.00 | N | No constraint | 9.48 | Summer | 8.67 | N | Summer | 7.46 | 7.78 | N | Security | 1 | Subtransmission circuit | Other non-traditional solution | No active planning | 1 - 3 years | Contractual agreement with a large customer to increase capacity over manage security limits during peak loading/ Build incomers from proposed Orari GXP optionally |
| Studholme (STU) | 16.18 | Summer | 20.00 | N | Security | 3.82 | Summer | 0.60 | N | Summer | 0.00 | 0.00 | N | Security | 1 | Transpower | Network upgrade | Planning stage | 1 - 3 years | Transpower plan to upgrade existing 2x10 MVA transformers at STU to 2x30 MVA GXP 2027. Network upgrades to switch/ transfer part of the load to other GXP/ Zone Sub by building HV feeder ties as a temporary solution. N capacity at zone sub transformer level is 60 MVA |
| Tekapo Village (TEK) | 5.20 | Winter | 13.80 | N | Security | 8.60 | Winter | 7.03 | N | Winter | 5.12 | 5.98 | N | Security | 1 | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Build second ZS (transformer) in Tekapo village and a second sub-transmission circuit beyond 2028 |
| Temuka (TMK) | 14.02 | Summer | 19.85 | N-1 | No constraint | 5.83 | Summer | 3.26 | N-1 | Summer | 0.33 | 1.60 | N-1 | Capacity | 2 | Other | Network upgrade | Planning stage | 1 - 3 years | Outgoing 11kV distribution feeder constraints from the zone substation needs upgrades |
| Timaru 11/33 kV (TIM) | 15.25 | Summer | 19.50 | N-1 | No constraint | 4.25 | Summer | 3.41 | N | Summer | 0.99 | 2.07 | N | Security | 9 | Ancillary equipment | Undecided | No active planning | Not applicable | Ancilliary equipment protection limits 19.5 MVA on each leg. Constraints can be alleviated through demand flexibility or non-network option under PAR zone substation |
| Twizel Village (TVS) | 4.09 | Winter | 6.25 | N-1 | No constraint | 2.16 | Winter | 5.86 | N | Winter | 3.19 | 4.75 | N | Security | 3 | Zone substation transformer | Network upgrade | No active planning | Not applicable | N-1 capacity reached by 2029 needing ugrades to existing zone sub transformers and build second sub-transmission circuit |
| Unwin Hut (UHT) | 1.05 | Winter | 1.50 | N | No constraint | 0.45 | Winter | 0.32 | N | Winter | 0.12 | 0.16 | N | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Meets Alpine security standard |
| Washdyke (11kV switching station) | 17.35 | Autumn | 28.30 | N-1 switched | No constraint | 10.95 | Autumn | 3.35 | N-1 | Autumn | 0.00 | 0.16 | N | Security | 9 | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Can be upgraded to a zone substation 2x40MVA by 2035 after the commissioing of proposed Timaru new 220/33 kV GXP with 2x120 MVA<br>Outgoing distribution feeder upgrades to reiinforce 11kV distribution in Washdyke area have also been planned |
| Timaru Urban (Switching stations) | 33.18 | Winter | 39.10 | N-1 switched | Security | 5.92 | Winter | 23.81 | N | Winter | 13.04 | 20.21 | N | Security | 3 | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Short-term solution is planned to alleviate security issue for 1-2 years, planning is in progress to enhance both capacity and security constraints on sub-transmission cables from Timaru GXP to the switching stations and inter-switching station ties in Timaru CBD and Port area. The need for a new switching station and/or zone substation has also been identified and is at initial planning stage depends on future demand growth at Timaru Port |

## Schedule 12c: Report on forecast network demand

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7 | **12c(i): Consumer Connections** | | | | | | |
| 8 | *Number of ICPs connected in year by consumer type* | **Number of connections** | | | | | |
| 9 | for year ended | **Current Year CY** | **CY+1** | **CY+2** | **CY+3** | **CY+4** | **CY+5** |
| 10 | | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** | **31 Mar 31** |
| 11 | *Consumer types defined by EDB** | | | | | | |
| 12 | Residential | 185 | 204 | 224 | 246 | 271 | 298 |
| 13 | Commercial | 85 | 94 | 103 | 113 | 124 | 137 |
| 14 | Irrigation | 15 | 15 | 15 | 15 | 15 | 15 |
| 15 | Subdivision | 29 | 29 | 29 | 29 | 29 | 29 |
| 16 | [EDB consumer type] | | | | | | |
| 17 | **Connections total** | **314** | **341** | **371** | **403** | **439** | **479** |
| 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 | 170 | 180 | 190 | 200 | 200 | 210 |
| 24 | Capacity of distributed generation installed in year (MVA) | 1 | 25.3 | 1.4 | 1.5 | 1.6 | 2 |
| 25 | **12c(ii) System Demand** | | | | | | |
| 27 | **Maximum coincident system demand (MW)** | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 28 | GXP demand | 157 | 165 | 170 | 183 | 186 | 189 |
| 29 | *plus* Distributed generation output at HV and above | 1 | 3 | 3 | 3 | 3 | 3 |
| 30 | **Maximum coincident system demand** | **158** | **168** | **173** | **186** | **189** | **193** |
| 31 | *less* Net transfers to (from) other EDBs at HV and above | | | | | | |
| 32 | **Demand on system for supply to consumers' connection points** | **158** | **168** | **173** | **186** | **189** | **193** |
| 33 | **Electricity volumes carried (GWh)** | | | | | | |
| 34 | Electricity supplied from GXPs | 937 | 969 | 987 | 1,062 | 1,082 | 1,101 |
| 35 | *less* Electricity exports to GXPs | 15 | 15 | 15 | 15 | 15 | 15 |
| 36 | *plus* Electricity supplied from distributed generation | 33 | 71 | 72 | 74 | 76 | 78 |
| 37 | *less* Net electricity supplied to (from) other EDBs | | | | | | |
| 38 | **Electricity entering system for supply to ICPs** | **955** | **1,025** | **1,044** | **1,121** | **1,143** | **1,164** |
| 39 | *less* Total energy delivered to ICPs | 918 | 985 | 1,004 | 1,078 | 1,099 | 1,119 |
| 40 | **Losses** | **37** | **40** | **40** | **43** | **44** | **45** |
| 41 | | | | | | | |
| 42 | **Load factor** | **69%** | **70%** | **69%** | **69%** | **69%** | **69%** |
| 43 | **Loss ratio** | **3.9%** | **3.9%** | **3.9%** | **3.9%** | **3.9%** | **3.9%** |

## Schedule 12d: Report forecast interruptions and duration

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

| 8<br>9 | for year ended | Current Year CY<br>31 Mar 26 | CY+1<br>31 Mar 27 | CY+2<br>31 Mar 28 | CY+3<br>31 Mar 29 | CY+4<br>31 Mar 30 | CY+5<br>31 Mar 31 |
|---|---|---|---|---|---|---|---|
| 10 | **SAIDI** | | | | | | |
| 11 | Class B (planned interruptions on the network) | 80.0 | 125.5 | 123.9 | 103.4 | 145.7 | 144.1 |
| 12 | Class C (unplanned interruptions on the network) | 112.9 | 87.1 | 92.0 | 95.6 | 99.9 | 96.6 |
| 13 | **SAIFI** | | | | | | |
| 14 | Class B (planned interruptions on the network) | 0.40 | 0.44 | 0.48 | 0.51 | 0.55 | 0.58 |
| 15 | Class C (unplanned interruptions on the network) | 1.11 | 0.84 | 0.89 | 0.93 | 0.97 | 0.94 |

## Schedule 13: Report on asset management maturity

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2026 – 31 March 2036

| 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? | 3 | A clear, approved Asset Management Policy is available on the Grid. It aligns with corporate objectives and guides AMP development and asset-related decisions. | 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? | 3 | A documented AM Strategy is available on the Grid and links corporate objectives to the AMP. It guides fleet strategies and programme development. | In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail. | Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management. | The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation. |
| 11 | Asset management strategy | In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship? | 3 | Lifecycle strategies are available in Adept application. The AMP has been published and is accessible. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 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? | 3 | Alpine establishes asset management plans across the full asset life cycle using structured processes aligned with governance, standards, and risk-based decision-making, ensuring consistency between planning, delivery, operation, and renewal activities. These plans are documented, maintained, and applied in practice, supporting informed and coordinated asset management decisions. | 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). |
| 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? | 3 | Alpine communicates its asset management plans to relevant internal and external stakeholders through established governance, reporting, and coordination forums at a level appropriate to their roles in delivery. However, an opportunity exists to improve and streamline project implementation and clearly define the value chain to reduce project deferrals and strengthen alignment between planning and execution. | 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 | Designated responsibilities for delivering asset plan actions are documented and applied through defined roles and work programmes; however, the level of detail and consistency can be improved. An opportunity exists to strengthen clarity and alignment of responsibilities to support more effective and accountable delivery. | 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)?<br><br>(Note this is about resources and enabling support)" | 2.5 | A minimum viable product has been established, with the budget and Q1 approvals obtained through the ELT. Core planning documents such as the Works Delivery Plan and associated CAPEX and OPEX are in place, although the Annual Works Plan still requires formal ELT or Board sign-off. Work is progressing on the development of a scheduling system that will support analysis of resources, plant, and other operational requirements. | It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales. | The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities. | The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 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? | 2.5 | Contingency plans, communication plans, and risk registers are available and in use; however, further documentation is needed to better evidence and support this. | 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. |
| 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)? | 3.5 | The organisation chart, position descriptions, delegation of authority, and communications plans are in place and being used; however, further work is still required to fully develop and embed the RASCI. | 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? | 3 | Human resource capacity has been confirmed as available, and a detailed programme of works is in place. Financial and physical resources are also available; however, the supporting evidence to demonstrate this needs to be strengthened. | 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 | No formal communication plan has been sighted. However, the AMP improvement project included a presentation outlining the intended approach for communicating the AMP across the organisation. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 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 | Work is progressing on confirming contract values across the different procurement pathways, including sole source, lightweight procurement, and full tendering. Finalisation of these values is still required to support consistent and transparent procurement decisions. | Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard. | Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity. | The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities. |
| 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)? | 3 | A signed Asset Management Plan is in place, is being used, and has been reviewed over time. Position descriptions are available; however, there is no evidence they have been formally reviewed. An assessment of human resource requirements is also in place and being used. Succession planning remains an area for improvement. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 49 | Training, awareness and competence | How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies? | 2 | Competency reviews and training have been lacking; however, we are now starting to develop and implement a formal framework to address this. | Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements). | Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers. | Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database. |
| 50 | Training, awareness and competence | How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience? | 1.5 | Alpine uses Enlight to manage goal maps. However, while the direction for a skills audit and training needs analysis has been defined, these initiatives have not yet been implemented. | 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? | 2 | Some communication activities are carried out individually, although a formal Communication Plan has not yet been developed. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 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 | Documents available but not communicated widely | Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55). | The management team that has overall responsibility for asset management. Managers engaged in asset management activities. | The documented information describing the main elements of the asset management system (process(es)) and their interaction. |
| 62 | Information management | What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system? | 3 | Documentation is established and in use. A recent example is the deployment of a new GPS system incorporating a data dictionary, supported by an ongoing training programme. It is not currently clear whether relevant performance indicators have been defined. | "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.<br><br>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 | As the GIS system is undergoing replacement, evidence to confirm fitness for purpose is currently limited. No formal data cleansing plan has been established. | "The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale.<br><br>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? | 3 | A number of review mechanisms are established, including governance through the Transformation Team and the Digital Architecture Board. | 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? | 3 | Asset and defect risks are assessed using structured likelihood-and-consequence criteria, supporting prioritisation and planning. | 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? | 2 | A framework is in place and risks are identified and incorporated into design processes; however, risk is not consistently integrated into training. Progress continues with the Safety in Design framework and Risk Matrix. Recent examples, including the introduction of new protection relays and composite crossarms, have incorporated training as part of their implementation. | 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 has established and consistently applies processes to identify, provide access to, and comply with legal, regulatory, statutory, and other asset management requirements, embedded within governance frameworks, standards, and risk-based asset management practices. However, while these processes are operating effectively, they are not fully documented, presenting an opportunity to formalise existing practices to improve consistency, transparency, and auditability. | 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? | 2.5 | Most artefacts are currently tracked within Adaptive Work, providing a consistent central repository. Additional work is required to document the procedures and policies associated with each artefact. | 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 | Some evidence sources are not yet available, including contracts with external suppliers and maintenance KPIs. Current practices exist but are undocumented, and these can be formalised based on established operational processes. | 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? | 3 | Condition and performance data drives interventions. Dashboards and network indicators exist and are being used. | Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s). | A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate. | Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s). |
| 99 | Investigation of asset-related failures, incidents and nonconformities | How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated? | 3 | Accountabilities are broadly assigned across AM teams, supported by governance and delegations. A more detailed RASCI across the value chain would improve clarity of decision ownership and hand-offs. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 105 | Audit | What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))? | 2 | Alpine is conducting audits of its asset management system, with draft procedures and defined scope in place; however, these are not yet fully documented or consistently embedded. An opportunity exists to formalise the audit process and introduce a structured risk assessment of Asset Management System quality to strengthen assurance and continuous improvement. | This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7). | The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments | The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers. |
| 109 | Corrective & Preventative action | How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance? | 3 | RCFAs and CIMS records support issue management, and learning sometimes informs design and standards. | 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? | 3 | Improvement activities occur, with lessons reflected in designs and specifications. The PDD process has improved. | 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. |

## Schedule 13: Report on asset management maturity continued

| Question No. | Function | Question | Score | Evidence–Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 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 | Industry forums, EEA conferences, vendor presentations, and professional networks are used to identify emerging innovations. Identified opportunities are subject to peer review and due diligence, followed by field trials to validate suitability and development of a business case prior to implementation. A recent example is the use of on-ground conductors. | 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.<br><br>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.<br>OR<br>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.<br><br>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.<br>OR<br>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.<br><br>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.<br><br>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).<br>OR<br>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.<br><br>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.<br><br>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)?<br><br>(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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>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 2027

### Schedule 14a - Mandatory Explanatory Notes of Forecast Information

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Amendment Determination 2024)*

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 2027 represent the forecast actual capital expenditure the year ending 31 March 2027. The constant price for 31 March 2026 represents the forecast values as per the prior year AMP.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts (using 2027 real dollars) were inflated by 2% for 2028, and 2.1% for the remaining 9 years of the AMP. These forecasts are based on Treasury and ANZ forecasts at the time of preparing our AMP. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% in 2027, and 2.1% 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 2027 represent the forecast actual operational expenditure the year ending 31 March 2027. The constant price for 31 March 2026 represents the forecast values as per the prior year AMP.

To derive the operational expenditure in nominal dollar terms, the constant price forecasts (using 2027 real dollars) were inflated by 2% for 2028, 2.1% for the remaining 9 years of the AMP. These forecasts are based on Treasury and ANZ forecasts at the time of preparing our AMP. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2% in 2027, and 2.1% in the other years.

# Appendix F: Schedule 17 certification for year-beginning disclosures

We, Tony King and Stephen Lewis, 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

26th March 2026

Date

Director

26th March 2026

Date

24 Elginshire Street, Washdyke, Timaru 7940 **P.** 0800 66 11 77 **www.alpineenergy.co.nz**