28 March 2025

ASSET MANAGEMENT PLAN

APRIL 2025 – MARCH 2035

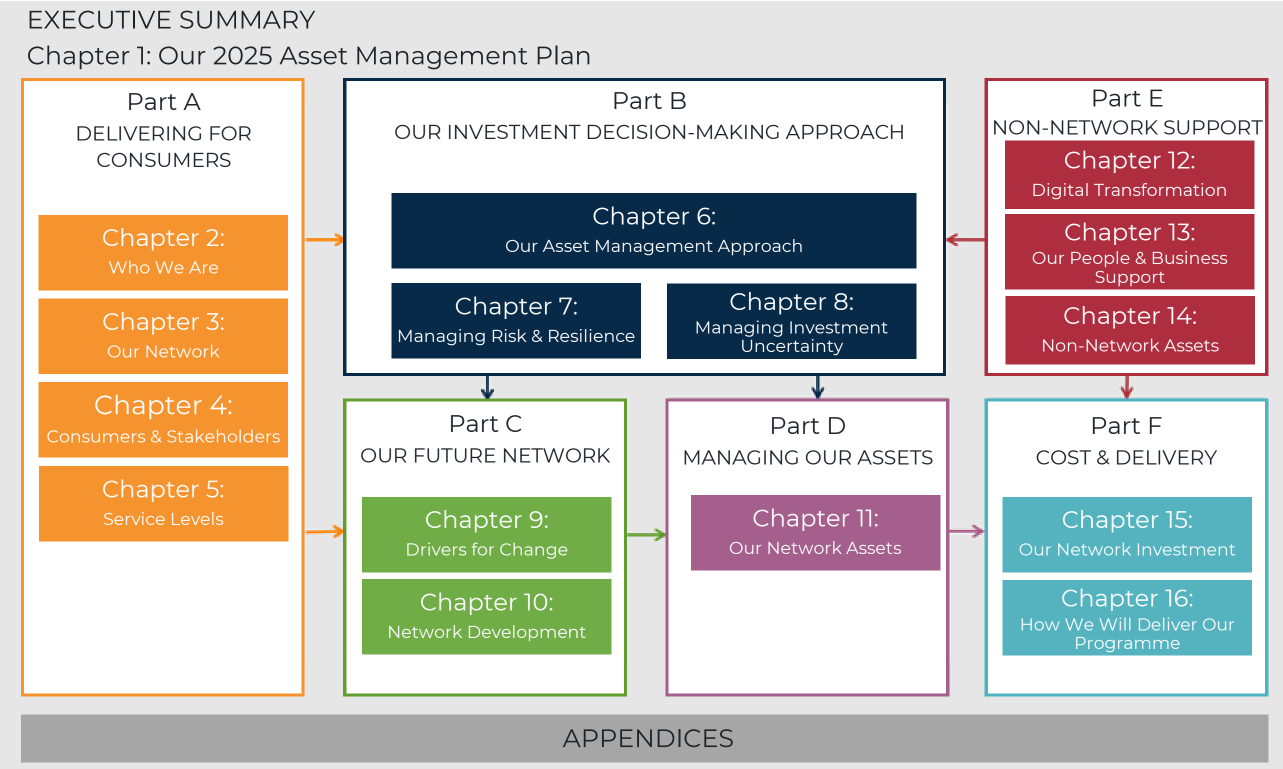
Aurora
ENERGY

About this plan

This Asset Management Plan (AMP) provides an overview of Aurora Energy's plan for the electricity distribution services we supply. It focuses on a 10-year planning period from 1 April 2025 to 31 March 2035, and was approved by our Board on 28 March 2025.

Navigating this plan

This AMP has been developed to meet the different needs of our stakeholders, so we've arranged it into different parts to focus on their various needs.



EXECUTIVE SUMMARY

This part provides an overview of our Asset Management Plan, structured around our three sub-networks: Dunedin, Central Otago & Wānaka, and Queenstown. It outlines key influences considered in our investment decision-making and our proposed work to manage our assets for the next 10 years to keep delivering for consumers.

PART A: DELIVERING FOR CONSUMERS

This part is aimed at consumers and stakeholders. It provides an overview of our network, how we understand the needs and expectations of consumers and stakeholders, and the service levels we provide to them.

PART B: OUR INVESTMENT APPROACH

This part gets into more detail about how we make investment decisions. It is aimed at our internal teams, executive, and key stakeholders, such as councils, who need to understand the direction and thinking behind our investments.

PART C: OUR FUTURE NETWORK

This part focuses on the future, examining our challenges and drivers for change. It is aimed at our internal teams and key stakeholders, such as councils, who will be working alongside us to provide other services that may intersect with or depend on our network.

PART D: MANAGING OUR ASSETS

This part focuses on the assets we already have. It is aimed at our internal teams who are managing these assets and gives direction on key strategies we will use to manage these assets effectively.

PART E: NON-NETWORK BUSINESS SUPPORT

This part provides details around our non-network business support processes and assets. It includes a focus on how organisational approaches to technology and people are integrated into our asset management approach and is aimed at our internal teams and executive.

PART F: COST & DELIVERY

This part provides a summary of our projected investment for the next 10 years and how we will deliver the work required. It is aimed at our consumers, stakeholders, and internal teams.

Contents

CHAPTER 1

OUR 2025 ASSET MANAGEMENT PLAN

1.1. PURPOSE OF OUR AMP

Our AMP demonstrates to consumers, stakeholders, and other interested parties how we plan to invest in our network over the next 10 years and deliver on our purpose of *'enabling the energy future of our communities'*. It demonstrates our commitment to building an electricity network that delivers a safe and reliable supply now, while making progress toward a more sustainable and digitally enabled supply in the future.

1.1.1. AMP objectives

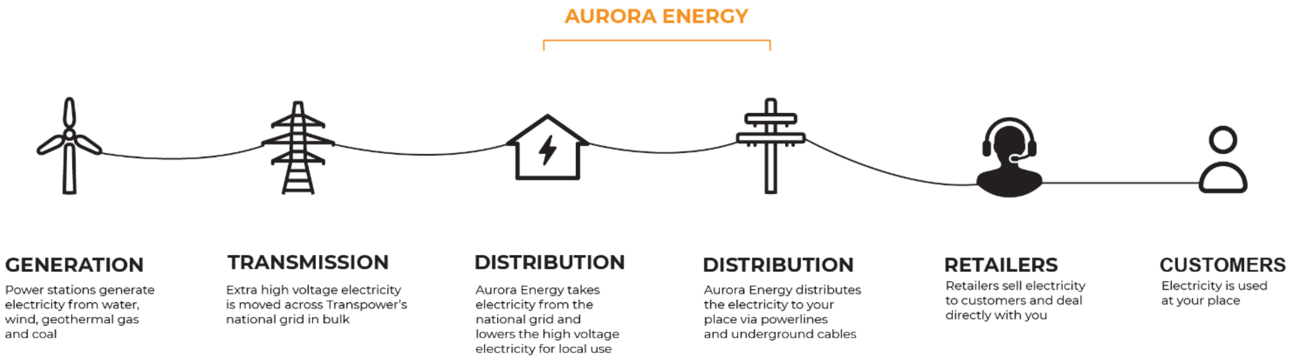
The objectives of our 2025 AMP are to document, communicate and demonstrate the Aurora Energy approach to:

- Continuously improving the safety of our assets through effective asset management and planning
- Implementing asset management and planning strategies that effectively serve the evolving needs of our community
- Investing in our infrastructure to facilitate network evolution and anticipated energy demands
- Addressing uncertainty, including how we prioritise and re-prioritise our investment plan to best serve our community
- Implementing asset management practices aimed at optimising lifecycle costs while ensuring the health and performance of our assets
- Identifying emerging risks and implementing strategic responses to strengthen network resilience against potential future threats
- Engaging with consumers, including how we foster transparency in our operations
- Ensuring regulatory compliance by adhering to relevant laws, regulations, and industry standards
- Leveraging technological advancements to enhance operational efficiency and facilitate data-driven decision-making processes

1.1.2. AMP regulatory context

Aurora Energy Limited is a regulated Electricity Distribution Business (EDB). We take electricity from Transpower's national grid to power your home, business and the wider community, delivering a safe, reliable and sustainable electricity supply to more than 200,000 people across Dunedin, Central Otago & Wānaka, and Queenstown. Our principal regulators are the Commerce Commission and the Electricity Authority.

Figure 1-1: How electricity gets to you



AMP PLANNING PERIOD

Our 2025 AMP covers a 10-year planning period, from 1 April 2025 to 31 March 2035. This marks the beginning of the 2026 regulatory year (RY26).

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012 (Determination).

A reference setting out how our AMP meets all our regulatory Information Disclosure requirements is included in Appendix I.

CPP DEVELOPMENT PLAN

Aurora Energy is currently subject to a Customised Price-quality Path (CPP), which applies for the period 1 April 2021 to 31 March 2026 and enables Aurora Energy to deliver a programme of spending to undertake essential maintenance and upgrades on the network.

As part of our CPP, Aurora Energy was set additional disclosure requirements to allow the Commerce Commission to assess our performance, including a CPP Development Plan. This publicly available standalone document sets out several business improvement initiatives directed toward key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe the improvements will bring genuine benefit to consumers. The Development Plan is available on the Aurora Energy website and progress against it is reported in our Annual Delivery Reports.

1.2. EXECUTIVE SUMMARY

1.2.1. Our 2025 AMP

This AMP outlines Aurora Energy's approach to managing its electricity distribution assets during the period from 1 April 2025 to 31 March 2035. Our AMP demonstrates to consumers, stakeholders and other interested parties how we plan to invest in our network over this period and deliver on our purpose of *'enabling the energy future of our communities'*. We will do this by enabling our people to drive innovation to deliver a sustainable and resilient electricity distribution network that meets the needs of consumers and shareholders, now and in the future.

Our AMP is structured to enable clear and pragmatic communication of our strategies and methodologies. Our focus has been on creating an informative plan that is directly relevant to the needs of our communities and stakeholders. Through AMP25, we strive to communicate our plans in a manner that is succinct, straightforward, and useful for all our readers. We continue to offer an expanded level of detail about our planned expenditure to reflect the significant work required throughout our CPP and AMP period.

1.2.2. What's changed?

Last year we signalled that while we continue to strongly prioritise safety, we had begun to take some of the steps necessary to enhance the resilience and reliability of our network for consumers – a medium to longer term goal.

This AMP reflects the progress we have made with respect to planning and preparedness toward enhancing the resilience and reliability of our network.

We continue to demonstrate how the progress we are making with asset management maturity is enabling us to meet the majority of our CPP Safety Development Plan (SDP) objectives while catering for the unprecedented levels of growth we are experiencing on our network and meeting the forecast level of expenditure needed for the AMP25 period (RY26–RY35).

Of significance is the challenge we face in the Upper Clutha and Queenstown regions. In the Upper Clutha, the demand from Cromwell GXP is growing at a rate that is signalling a need for significant investment in this AMP period. In the last 10 years, demand grew by 20 MW and this year it peaked at 5 MW more than last year. Over the last four years, demand has grown by 7 MW, an annual average increase of 2 MW. Against this backdrop, enabling just-in-time growth and electrification in the Upper Clutha Region while maintaining continuity of supply for our customers in the region is a unique and complex challenge.

Having worked through stakeholder consultation, reviewed demand forecasts to account for significant additional point loads, and undertaken options analysis, we are currently in the position of having a foreseeable but significant one-off investment need, which has increased in forecast cost on our last AMP in the order of $25m. Until a detailed design has been completed, the costs associated with this investment will entail a level of uncertainty.

While uncertainty has been a theme in the past, it is particularly pertinent to this AMP, as we transition to DPP4 while simultaneously defining the solution to our biggest challenge today: the need for a step change in supply to the Upper Clutha Region. The change – outlined in more detail below – is prudent to enable the network development required now, but also in consideration of continued growth over a 25-year period. In other words, the updated plan represents a more sustainable plan that will enable a solution that lasts beyond the forecast 10 years, looking out to 2050.

From a resiliency perspective, we have made some progress in defining critical spares. This work was expedited because we had to deploy the existing spare power transformer for use at the Remarkables zone substation during this year, as a result of an in-service failure. In carrying out this work, we undertook a criticality analysis, including consideration of renewal and development plans, increasing demand, security of supply, and access to alternate temporary and permanent solutions. Our investment plan allows for the recommendations from this analysis and includes the procurement of two new spare power transformers over the next five years.

In the context of the changing landscape and the need to set our best view of a multi-year plan, we have set out our approach to investment prioritisation. Each year we review and refine our investment plan, informed by the latest information available to us, both externally (e.g. demand growth) and internally (e.g. our continually improving understanding of risk). It is inevitable that with the uncertainty we face, we will need to flex our plans to optimise overall benefit to the customer. Chapter 8 outlines how we identify investment priorities, including context as to what has been de-prioritised in this plan.

We continue to prioritise our plan, with a safety-first focus. The need for prioritisation has been driven year on year by greater than forecast inflation coupled with growth in the Central Otago region that surpasses the forecasts at the time our CPP was determined. While our maturing asset management practices are enabling us to better optimise renewal investment, many of the gains are offset by increasing costs. Specifically, while the volume of forecast safety sensitive renewals is declining, the associated investment remains high.

As the CPP programme of investment in the network nears completion (31 March 2026), this AMP and our 10-year forecast look beyond the CPP to our next big challenges:

- Demand growth, particularly in Central Otago
  - Meeting the needs arising from continued population growth and development in the region
  - Enabling decarbonisation of energy sources to meet climate change goals
- Maintaining a safe network
  - Continuing to enhance our asset management practices and maturing our understanding of asset condition, health, impact of failure (safety), and optimisation of investment
  - Refining, optimising, and re-prioritising plans, informed by continual enhancement of asset management practices
- Maintaining and enhancing the reliability of our network
  - Tracking and actively managing emerging trends of sub-optimal continuity of supply service levels
  - Investing in network configuration enhancements to minimise the number of customers impacted by faults
  - Enhancing our understanding of vegetation fault causes and optimising vegetation management investment
  - Maturing our oversight and practices for managing power quality
- Improving the resilience of our network, including preparedness for high impact low probability (HILP) events
  - Undertaking HILP analysis
  - Determining spares required
  - Securing strategic spares storage facilities
  - Securing spares (our five-year plan currently includes two critical spare power transformers)
  - Undertaking asset hardening programmes where higher loading, such as where greater (than design) exposure to wind creates network vulnerability

While we face ongoing substantial investment levels and increasing costs, we recognise the importance of good asset management and – critically – the ability to make evidenced-based investment decisions to deliver a safe network that meets the needs of our customers for the least possible cost. We have an increased focus on enabling evidence-based decision making through continual improvement of our asset management practices. Our asset management approach is discussed in detail in Chapter 6.

1.2.3. Our network

Our network is split into three sub-networks. Each has a grid exit point (GXP), which forms the interface between Transpower's transmission network and our distribution network. There are two GXPs for our Dunedin sub-network, two GXPs for our Central Otago & Wānaka sub-network, and one GXP for our Queenstown sub-network. We have structured this AMP to provide information aligned to these sub-networks and their GXP configurations.

Figure 1-2: Our GXPs

1.2.4. Engaging with consumers

Consumer needs directly inform our programmes, and we are committed to providing a high standard of service for all consumers. To do this, we listen to feedback from annual customer satisfaction surveys.

We are one of the few EDBs in New Zealand to have both a Customer Charter and a Customer Compensation Scheme, where payment is made to customers when defined service levels are breached. The concept behind this scheme is to simultaneously compensate affected customers while providing an incentive to meet service level targets.

Since our last AMP, we have published a new Customer Charter that is easier to understand and reflects what our customers have told us through the consultation process. The details of the new charter are discussed in Chapter 4.

1.2.5. Service levels

We use specific measures and targets to track how well we meet the needs of consumers through the services we provide. In turn, this helps us show our stakeholders that our approach to asset management is producing the intended results. Service levels are described extensively in Chapter 5.

Our traditional target service levels include safety, reliability, and customer service. Our focus in the past 12 months has been on driving down the backlog of assets that pose a safety risk while maturing our understanding of asset failures and asset health. In doing so, we are also getting better insights into reliability performance drivers and the actions that will enable us to successfully meet the targets we set ourselves.

One important service performance indicator for consumers is the number of unplanned outages on our network. Figure 5-1 and Figure 5-2 in Chapter 5 provide a summary of our historic and forecast unplanned outage performance. Our analysis concludes that we have seen a stabilisation or slight improvement in performance since we increased network expenditure in 2018. The year ending March 2023 saw a small number of large outages, and we have since addressed the issues that caused them.

At the time of drafting this AMP, the year ending March 2025 was tracking well, with an expected improvement on recent performance.

1.2.6. Managing risk & resilience

USING RISK IN DECISION-MAKING AND INVESTMENTS

Managing risk is an important part of our asset management decision-making approach. Our risk management approach is consistent with the international risk management standard ISO 31000:2018 and enables us to manage the risks and opportunities relevant to achieving our business objectives.

As described in Chapter 7, the risk presented by our assets is non-negotiable. We take a holistic approach that considers risk in every aspect of asset lifecycle management; and in delivering our CPP, we have taken the decision to target safety risk as our highest priority. The safety risk driver is equally paramount for everyone – be they public, staff, or contractor. This said, recognising that there are different levels of training, experience and exposure to any hazards presented by our assets, we draw a distinction between the public and staff. By evaluating the location and potential impact of these risks, we ensure our spending is targeted where it will be most effective for enhancing public and operational safety.

As part of our maturity pathway, we are actively developing the way in which we calculate and express risk. Manging risk is central to our shift to an evidence-based investment plan. The process is one of continual improvement and the journey will take time. But through a shift to condition-based asset health assessment and a more robust and documented understanding of asset failure modes underpinned by root cause analysis on asset failures, we are improving our ability to manage risk. As we build more robust datasets, we will be better equipped to mature our risk quantification.

The progress we have made in documenting our strategies for each fleet is explained in Section 6.4. Expanding our focus in the medium term, we are developing a broader approach that encompasses reliability risks, thereby enhancing our existing framework of risk-based decision-making. This includes a detailed evaluation of network capacity and resilience, acknowledging the need to balance safety with network performance and sustainability.

We evaluate the success of our risk-based approach by verifying the asset risk levels that we forecast in our CPP Safety Delivery Plan. In addition to evaluating our annual progress against the plan, we continue to assess our network's performance against existing and developing service levels, adjusting our secondary investment drivers accordingly.

BUSINESS CONTINUITY AND EMERGENCY RESPONSE

We recognise our importance as a lifeline utility and take steps to ensure we can respond and function during and after emergencies. Our approach to business continuity is based on the *4Rs framework* as used by emergency services: *Reduction*, *Readiness*, *Response*, *Recovery*. We have also included *Review* into this framework, to ensure we are continually improving our business continuity.

BUILDING RESILIENCE

As mentioned before, this plan expands our focus on safety, to include reliability and resiliency in the medium term. Section 7.4 details the proactive stance Aurora Energy is taking to address the resilience of our network to natural hazards such as earthquakes, including seismic reinforcement of our zone substation buildings. Climate change is expected to increase the number of storm-related events and raise the sea level. We view climate change not as a standalone challenge but as a significant factor that amplifies the probability and impact of various natural hazards. This understanding is integral to our asset management and strategic planning, guiding a comprehensive approach to enhancing network resilience.

We are addressing immediate resilience challenges and proactively considering future spending and improvements to network resilience. Our investment will be guided by our assessment against the Electricity Engineers Association Resilience Management Maturity Assessment Tool. The tool is consistent with the 4Rs framework and enables us to identify gaps in our maturity across several categories. For details, see Section 7.4.

With a resiliency portfolio in our AMP and associated forecast expenditure of $20 million across the 10-year period, we are signalling the need to continue with investment beyond what we currently have detailed plans for, so that we can prepare for HILP events that may affect our ability to provide service continuity as a lifeline utility. Within the DPP4 period we have allowed expenditure to secure two new spare power transformers as well as two spares storage facilities, one in Dunedin and one in Central Otago. Although we understand the heightened flood risks in Dunedin and the possible impact of a large Alpine Fault earthquake in Central Otago, we are undertaking HILP analysis to enable an informed investment approach to resiliency. Our strategy encompasses both actions undertaken and future exploratory work to better understand which assets are vulnerable to windstorms, for example.

RELIABILITY

We are aware of the increasing reliance on electricity in the future, particularly as consumers move away from traditional sources of energy and interact with our network differently. Consequently, we are actively managing the health of our assets, as well as taking action to reduce the impact of vegetation, severe weather, wildlife, and third-party interference leading to supply interruption. We aim to reduce the impact of planned outages on consumers by notifying them well in advance via their retailers and our website.

Table 7-3 outlines our initiatives to reduce the frequency of faults on our network. And in addition to reducing the number of unplanned outages across our network, we also aim to deliver benefits by reducing the impact of faults on consumers by improving the way our network and our fault staff respond to outage events, as shown in Table 7-4.

To improve reliability over the planning period, we have identified several investment initiatives. As elaborated in Section 7.5.2, our investment approach regarding reliability is driven by several factors:

- Zone substation renewals
- Growth and security investment
- Vegetation management
- Asset inspection trials

We also seek to improve reliability by developing our internal processes and analytical capability. We have realised benefits from improved and more targeted renewal programmes combined with a better understanding of faults and by proactively responding to our root cause analysis learnings. Ultimately, we aim to establish better performance targets, ensure we understand and learn from faults (including asset failures), monitor fault performance, and identify optimal investment solutions, while supporting continual improvement. These reliability improvement goals are explained in Section 7.5.

1.2.7. Our asset management approach

We have developed an asset management framework that ensures line-of-sight between consumer and stakeholder needs and our planned expenditure. The framework encompasses all elements of our business that contribute to asset performance, whether directly or indirectly. As we mature our asset management framework, we will continually review and update key processes and documents to reflect any improvements.

As our asset management matures, so does our data – as does our ability to make evidence-based investment decisions. And all of this supports our high-level asset management and organisational objectives.

Our Asset Management Policy sets out high-level principles that reflect Aurora Energy's vision and values. As explained in Section 6.2, this policy informs our asset management objectives, which in turn drive our strategic focus areas, as shown in Figure 6-4.

Our approach to asset management decision-making uses processes that test our planned expenditure – both overall and in terms of specific assets. Investment decisions take place within a system of responsibilities and controls that reflect the cost, risk, and complexity of the decision being considered.

1.2.8. Investment uncertainty

Much like its predecessor, this year's AMP finds us navigating a complex landscape characterised by various input drivers, each presenting a unique level of forecast uncertainty.

The primary driver of uncertainty is the rate at which we need to increase supply to meet transitional changes in demand and how we ensure we can respond to this in a holistic way. The global drive to decarbonise energy is being realised. However, the pace, extent, and locations of increases in demand for electricity still carry significant uncertainty, making forecasting expenditure over a 5 to 10-year period challenging. This includes uncertainty manifested in the extent of climate change impact and the effect of the emergence of – and expenditure on – new technologies to capture carbon or eliminate its creation, as the global effort gains momentum. Alongside efforts to reduce the impact of increasingly frequent major weather events associated with climate change, the emergence of new digital technologies creates new opportunities and community expectations to lift our asset management capability and services.

Because the pace of change continues to accelerate, many of the drivers informing our capital and operational expenditure forecasts are developed via the use of scenarios. Our AMP expenditure forecasts present one scenario that we consider is a minimum viable plan. We will review and flex our plan annually as new information becomes available. That is, every year we put forward the most certain plan we can, based on the information available to us at that time.

As detailed in Section 8.1, we have identified the following categories of investment uncertainty:

- Asset renewal
- System growth
- Decarbonisation and distributed energy resources (DER)
- Reliability
- Resilience
- Digital transformation
- Vegetation
- Consumer service lines

1.2.9. Drivers for change

Defined in Chapter 2, our priority investment drivers inform our network development investments. Chapter 9 details our key network development investments:

- Growth and security
- Consumer connections
- Reliability
- Power quality

The need for this expenditure is driven by a number of factors including system demand, security of supply, and power quality.

Another driver for network development is climate change. Chapter 9 details the three growth scenarios we developed based on our decarbonisation study (*Sustainable*, *Chaotic*, and *Alternative energy*). We have seen the effects on the sector of extreme weather events such as Cyclone Gabrielle and we recognise the need to have a robust resilience strategy and plan in place in response to climate risk.

SYSTEM GROWTH FORECASTS

The greatest areas of uncertainty are the pace and impact of electrification, the timing of large developments, and the impact of changing energy needs on growth expenditure. This includes process heat conversion and the low-voltage network requirements to enable connection of household electric vehicle charging and solar generation.

To help manage investment uncertainty, the Commerce Commission has created a regulatory mechanism called a *reopener*. This mechanism enables us to seek additional regulatory allowances at a later date in the event that a project excluded from the plan due to insufficient certainty goes ahead within the period.

When developing our system growth forecasts, we created a minimum viable plan to address known growth-related network constraints. We will rely on the Default Price Path (DPP) reopener mechanisms to respond quickly and seek approval for system growth projects where the need occurs during the DPP4 period.

We have developed a list (see Table 8-1) of potential growth-related projects which may trigger reopener applications. In the unlikely event that all projects identified as possible but with significant uncertainty were to materialise, the associated cost is estimated to add approximately $54 million of expenditure to the 10 year plan.

GROWTH & SECURITY INVESTMENT

Although we have based our planned expenditure on the *Sustainable* scenario, other traditional drivers for investment such as capacity shortfall to connect new consumers and security of supply gaps remain relevant, but at an accelerated rate with strong growth.

We classify our growth and security expenditure into two types of projects:

- **Major projects:** Apply to zone substations, subtransmission, or GXP related works. Major projects are forecast on an individual, project-by-project basis.
- **Distribution and LV reinforcement projects:** Distribution reinforcement allows us to add capacity to existing parts of the feeder network, create additional feeders or backfeed ties, upgrade from 6.6 kV to 11 kV, and install or upgrade voltage regulators.[1] LV reinforcement is a relatively reactive process, reflecting the

[1] Occasionally, the upgrade of a distribution transformer will occur as part of the above works, but more generally such work is delivered as part of our consumer connections work, which is described in Section 4.4.

lower value and higher volume of assets. The addition of new load is managed through our consumer connection process.[2] With the uptake of EVs gathering momentum and electrification of other fuel uses in households, we expect an increasing need to invest in additional capacity in some LV networks.

The drivers in Dunedin and Central Otago are distinct. Dunedin typically experiences modest growth primarily attributed to the conversion of thermal process heat and a strong uptake of light electric vehicles; however, we have noticed a slight softening in residential consumption, which we are monitoring. In contrast, Central Otago – particularly the Upper Clutha and Queenstown regions – is experiencing unprecedented growth driven by residential and commercial developments as well as tourism. Additionally, there is significant uptake of solar generation within the region.

We anticipate the robust growth in the Upper Clutha and Queenstown regions to continue beyond the ten-year AMP planning period (refer to Sections 10.6 and 10.7). Demand forecasts for both the Cromwell GXP, which supplies the Upper Clutha region, and Frankton GXP, which supplies Queenstown, indicate that demand will surpass the firm capacity of both GXPs within three to five years, respectively. We are planning and implementing tactical solutions to increase capacity for the short to medium term, as described in Table 10-10 and Table 10-18.

While we have undertaken a thorough and robust demand forecast, projections beyond a ten-year period carry considerable uncertainty, making investment decisions challenging.

For Upper Clutha, Aurora Energy and Transpower collaborated to develop a long list of options to address the demand growth. These options have now been shortlisted, with Transpower focusing on transmission and GXP solutions, while Aurora Energy addresses subtransmission and distribution options. The capital investments for Upper Clutha are substantial, reflecting future growth and the impact on customers in the region.

These options are developed using a minimum viable plan and staged development or with a just-in-time approach. To ensure a sustainable solution is implemented, the analysis considers inputs from key stakeholders in the region and incorporates the likely demand forecast out to 2050.

For Frankton GXP, short- to medium-term tactical solutions have been implemented to increase capacity (refer to Table 10-18).

Both regions need long-term solutions, requiring support and collaboration from local councils, communities, Aurora Energy, and Transpower. The specific details of the uncertainty associated with meeting growing demand in the Upper Clutha Region are discussed in greater detail in Chapter 8.

CONSUMER CONNECTIONS

Consumer connection capital expenditure (capex) facilitates the connection of new consumers to our network. On average, we connect around 1,200 homes and businesses to our network every year. For details, see Section 4.4.

New connections can range from a single new house through to a variety of businesses and infrastructure. Growth is significantly higher in Central Otago than in Dunedin, and small increases in demand in Central Otago can trigger network reinforcement projects.

DIGITAL TRANSFORMATION JOURNEY

Looking toward the future, Aurora Energy has prioritised rationalising the multitude of applications currently within the technology landscape, using increasing levels of software as a service (SaaS) solutions alongside on-premises solutions to ensure a sustainable, secure technology foundation.

Once rationalised, our ICT platform will make it possible for us to enable future energy choices for consumers. Our digital business transformation strategy will help us streamline priority processes, manage our assets predictively, and deliver capital works effectively.

[2] Note that LV reinforcement is concerned with the LV network impacts of new consumer connections, rather than the actual connections. Investments for the consumer connections themselves are discussed in Section 9.1.2.

The transformation has four elements, which are discussed in detail in Section 13.2.3. They are:

- Digitisation of core enterprise processes
- Optimisation of network configuration and operations
- Enhancement of business analytics/ insights and people empowerment
- Development of critical digital technology enablers

We will progressively deploy these capabilities across the business through DPP4 and beyond, prioritising implementation by consumer benefit.

PRIORITISING OUR PLAN

When challenging our investment plan, there is some – though limited – ability to flex.

Each year, reprioritisation is undertaken, informed by the most up-to-date information available to us relative to meeting the following priorities:

- Continuing to connect new customers and meeting the growing demands of existing customers
- Maintaining security of supply and quality of supply commitments
- Ensuring we are managing safety risk on our network

While the upward pressures of unprecedented growth and unforeseeable inflation have significantly impacted our ability to deliver the quantities of renewals predicted to be required at the time of the CPP application, we have largely managed to maintain progress against the outcomes we were striving for in our safety-focused CPP.

We have done this by significantly enhancing our asset management practices – predominantly our understanding of asset condition and the precursors to failure. For example, our enhanced condition-based approach to high volume fleets such as crossarms has enabled us to confidently signal the need for a significant reduction in investment.

However, because we have focused the renewal programme on achieving the necessary safety outcomes, we have not delivered the levels of renewals signalled for non-public-safety sensitive fleets and non-network security critical fleets. AMP25 continues in this vein.

While several programmes that have nil to low public safety impact (LV Cables and Distribution Cables) have been deferred, the renewal plan for our Protection fleet is an outlier in that it has not kept pace with the intent of the CPP plan. This is owing mostly to the close association of this fleet with larger zone substation projects and the challenges around delivery, with growth pressures and a shortage of engineers with the associated specialised skills. Therefore, this fleet has been set a stretch goal for the DPP4 period.

1.2.10. Network development

Network development is about responding to the drivers for change. We expand our network into new areas or increase the capacity or functionality of our existing network to meet the current and future needs of consumers in a cost-effective manner.

MAJOR PROJECTS IN EACH SUB-NETWORK

We have identified major projects to address network development needs over the next ten years. Figure 1-3 to Figure 1-6 show major projects planned for the Dunedin, Central Otago & Wānaka, and Queenstown sub-networks, respectively.

Figure 1-3: Large planned projects in the Dunedin sub-network

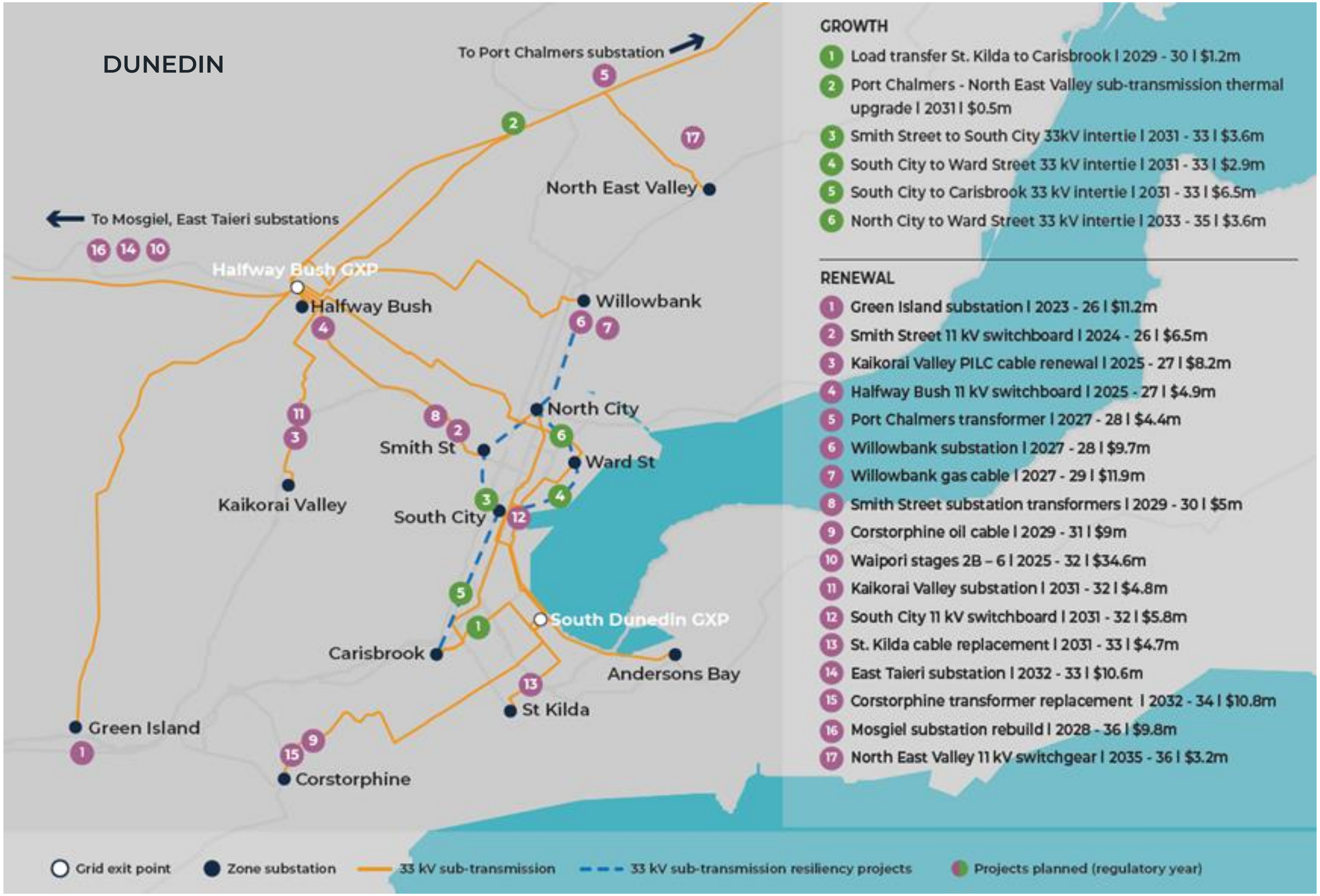


Figure 1-4: Large planned projects in the Central Otago & Wānaka sub-network (Part 1)

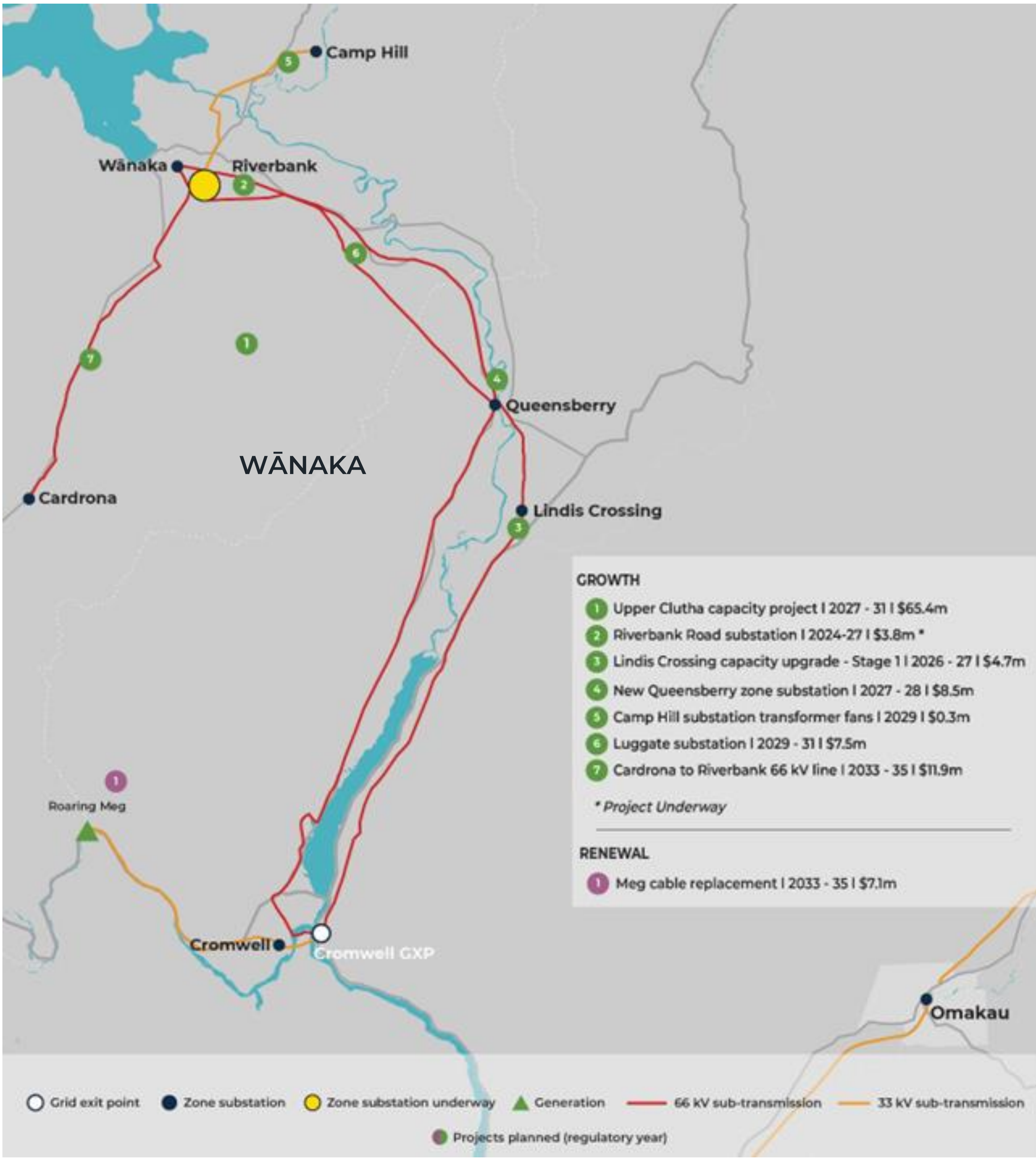


Figure 1-5: Large planned projects in the Central Otago & Wānaka sub-network (Part 2)

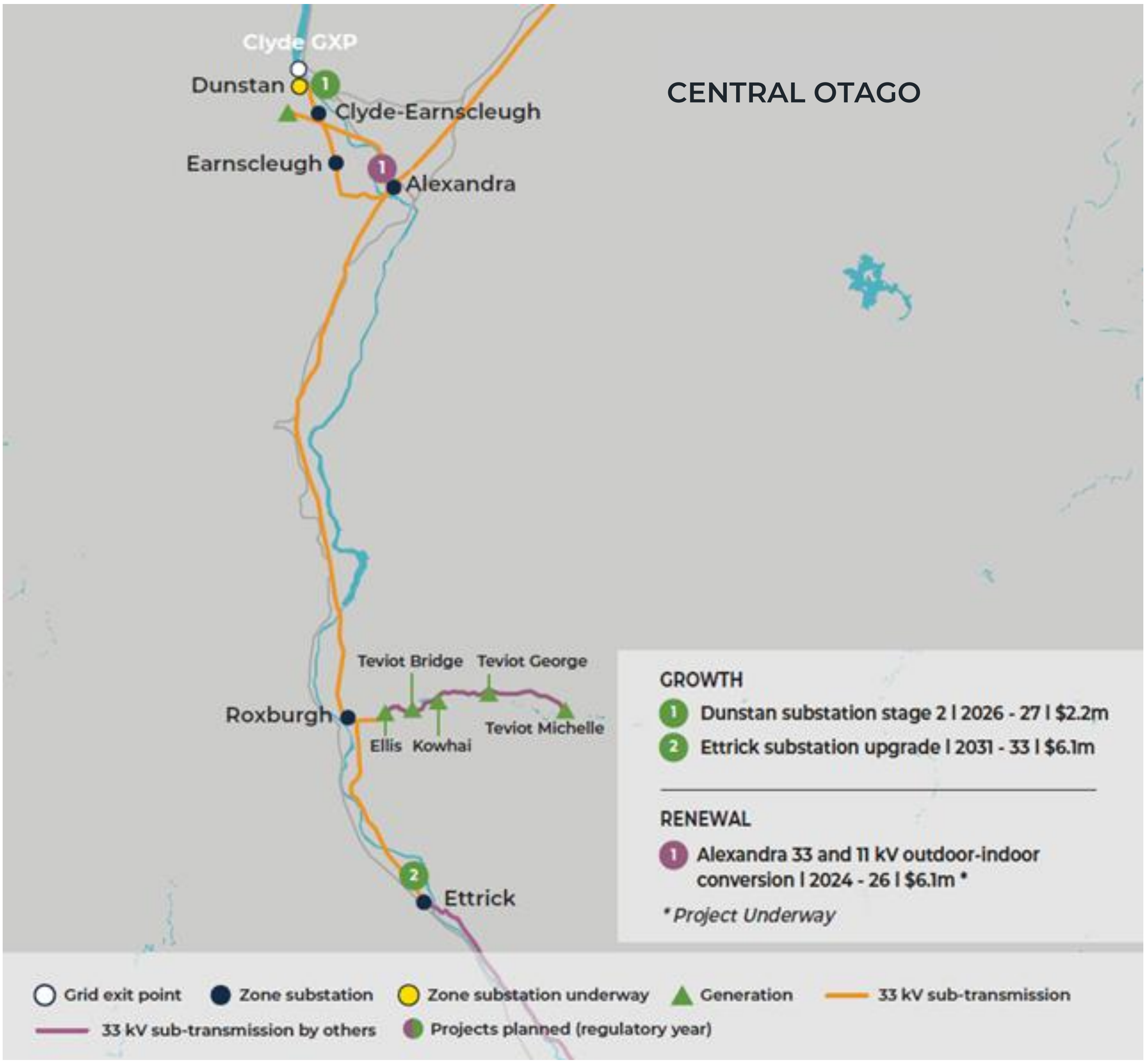
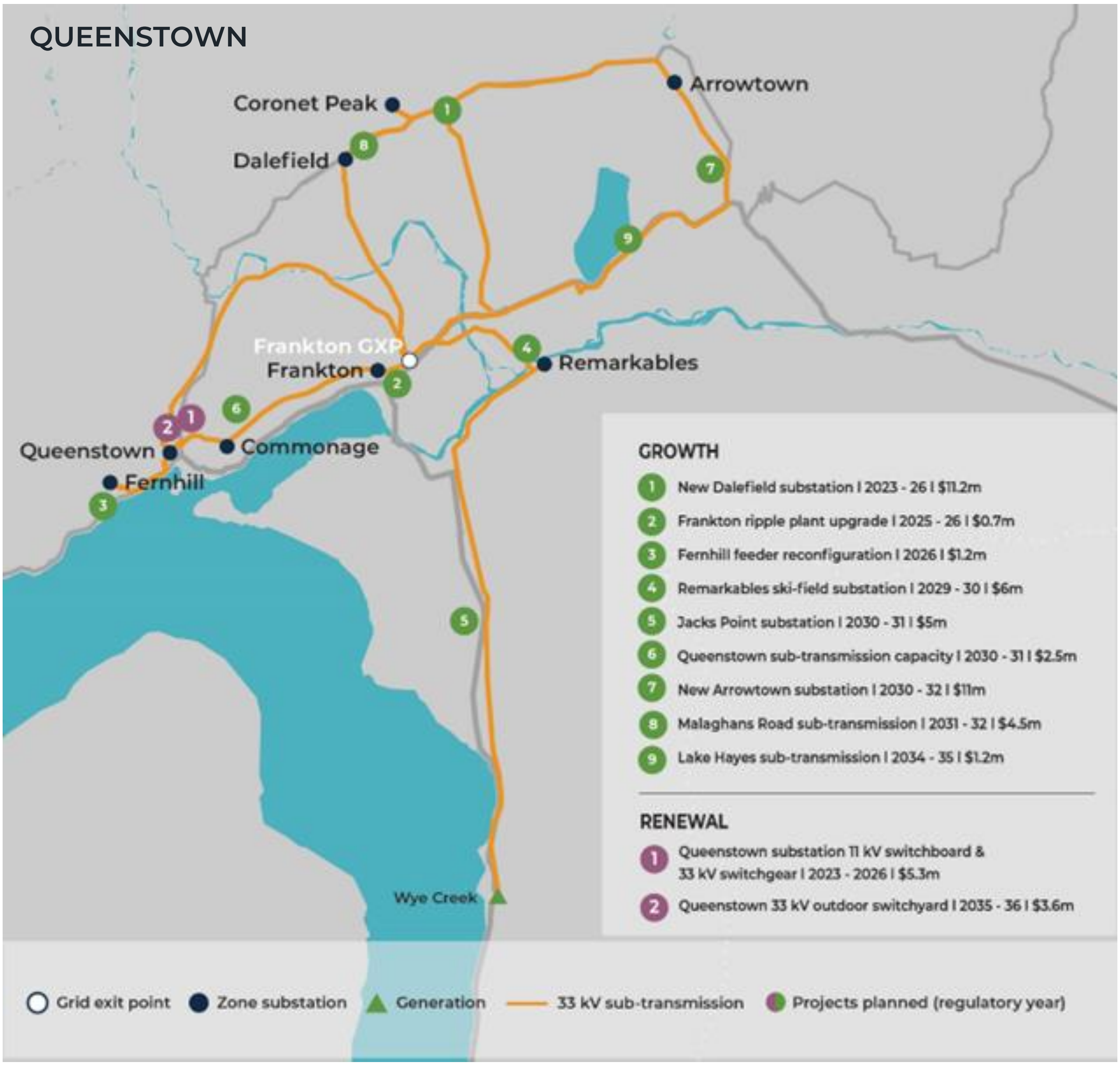


Figure 1-6: Large planned projects in the Queenstown sub-network



1.2.11. Network expenditure overview

Our capital and operational expenditure programmes are integral to the operation of our business throughout the 10-year planning period, and we have continued to focus on the delivery of these programmes in RY25. Our AMP includes our current best forecasts based on our maturing asset management practices, acknowledging that we are proactively continually improving these practices, reflecting our commitment to better asset management and optimisation of asset life, while effectively managing risk at the lowest cost to the customer. Through the development of fleet strategies, enhanced inspection standards, maturing asset health models, and introduction of root cause analysis on failed assets, as discussed further in Chapter 6, we have started to make significant improvements to the quality of the information informing our renewal and maintenance strategies.

When developing our 10-year plan we were mindful of cost escalation and affordability for consumers and our shareholders. We have used the latest available asset condition health and subsequently risk information to reprioritise our plan. We have done this to manage the backlog against our Safety Delivery Plan commitments and critically to make way for high priority growth-related projects. In some cases, we have applied engineering judgement where we believe future inspection information is likely to show more favourable asset condition than is suggested by current data. Further, we have intentionally deferred the renewal of non-safety critical fleets until such time as we have sufficient data to inform an evidence-based investment strategy.

Our plan for the CPP period (RY22 to RY26) prioritises safety for the public, contractors, and staff. We have also included modest levels of investment in reliability and resiliency as part of our reliability hotspot programme and seismic reinforcement of zone substation buildings. As we transition to the DPP4 period we will continue to focus on safety and meeting strong growth, including decarbonisation through electrification. Last year we introduced reliability and resiliency programmes with the goals of:

- Enabling reliability performance commensurate with the expectations of consumers and communities in areas of suboptimal performance
- Responding to stakeholder expectations for improved network resilience to climate change risks, storms, and other natural disasters

Our reliability programme encompasses a continuation of the reliability hotspot programme, additional reclosers, remotely operable switches, and new fault passage indicators. In some locations, we will change the network configuration to improve reliability. We propose a modest but targeted programme, with $3.6 million in the DPP4 period and $11 million across the 10-year planning period.

Our resiliency programme will include the provision of additional spares, backup generation, and possible hardening of storm exposed assets. We are prioritising the procurement of critical power transformer spares, while remaining focused on securing appropriately sized and located spares storage facilities. We have allowed for a modest but targeted programme, with $10.5 million in the DPP4 period and $20 million across the 10-year planning period.

As outlined in our CPP Annual Delivery Plan, we have made significant progress across the network in improving the health of safety-sensitive fleets, with the health of some fleets progressing ahead of our plan. Where we have not achieved plan, we have set a stretch target for the DPP4 period. For some fleets, however, we have reprioritised our plan for the remainder of the CPP period and beyond to ensure we meet our objective of reducing safety-related network risks as soon as practical. While our asset renewal programme continues to prioritise fleets with the highest inherent or residual risk on the network, we also continue to replace a reducing number of assets in lower safety risk fleets where asset health indicates an end-of-life asset. Other than the residual gains from the predominantly safety-driven renewals, targeted improvements in reliability or enhancement of resiliency are limited.

10-YEAR CAPEX FORECAST

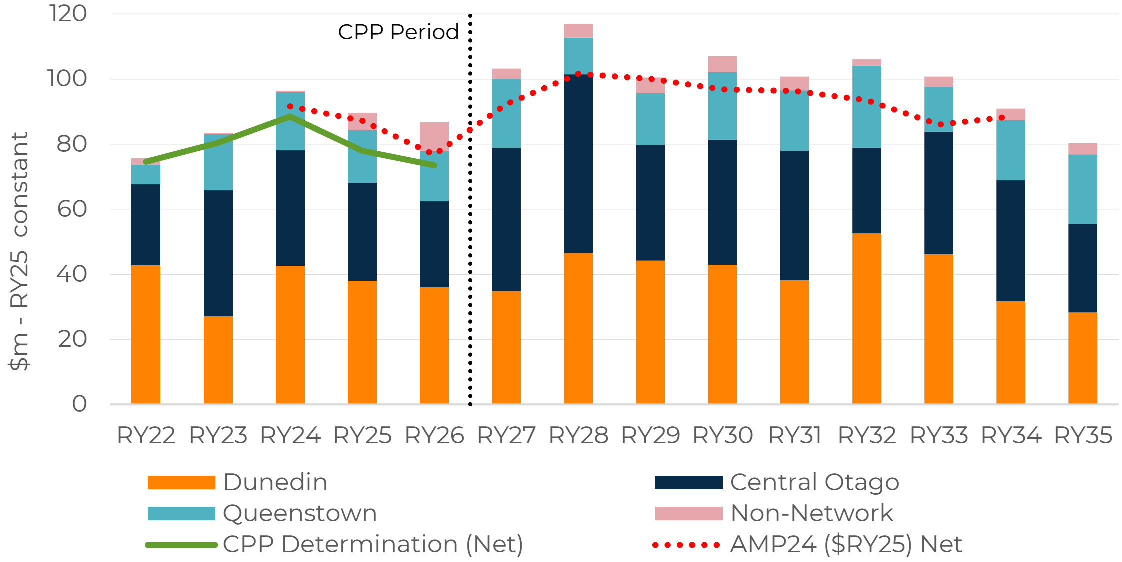
Figure 1-7 shows our capital expenditure forecast for the AMP planning period, as well as our forecast variance to our previous AMP, as at November 2024. Note, however, that our February 2025 update to Schedule 11a reflects higher than anticipated levels of RY25 capex.

The primary factors contributing to the increase in our forecasts include cost escalation, a significant increase in costs associated with addressing strong growth in the Upper Clutha, increased investment in the LV and distribution network, an increase in customer-initiated work, and a step change in non-network investment.

While we applied a 4% CPI adjustment to our master rates, analysis of the CPP Annual Delivery Report average total costs concluded that some specific rate adjustments above the 4% CPI, were necessary.

Ahead of AMP24, as part of our CPP improvement plan we completed a cost estimation improvement initiative to better estimate the cost of our major zone substation projects for both renewals and growth expenditure drivers. This has enhanced the robustness of our scoping and cost estimation for major projects. We are also planning further work to enhance the robustness of our building blocks or unit rates for large zone substation projects.

Figure 1-7: 10-year capex forecast by sub-network, Total ($m)



Strong system growth forecasts – particularly in the Upper Clutha, as discussed above – coupled with an emerging view from option analysis undertaken following consultation, underpin a significant increase in the forecast costs associated with enabling growth.

Strong consumer connection growth is forecast to continue, with recent connection activity supporting our forecast. This strong growth in Central Otago is compounded by decarbonisation occurring across all of our network.

Additional system growth expenditure is required to strengthen the subtransmission and 11 kV networks to meet strong consumer connection activity.

We are proposing a level of investment in renewals that enables us to get on top of the backlog and reach a steady-state investment level. This forecast is our best current view of the investment needed to proactively manage risk. While we have made progress in evolving our asset management practices, we acknowledge and are committed to continual improvement and subsequent flexing of our plan to best meet our business objectives, while serving the needs of consumers.

For AMP 2025, we have begun to identify priority investments in reliability and resiliency alongside the need for continued investment in network renewals and network growth, in addition to an increase in non-network investment over the next 10 years.

Overall, these variances result in an approximately 13% increase in capital expenditure over the reporting period. **Table 15-5** in **Chapter 15** gives a detailed view of our capex forecast variance.

All financial values are expressed in $RY25 constant price New Zealand dollars, except where specified otherwise.

10-YEAR OPEX FORECAST

For operational expenditure (opex), the forecasts generally follow the same methodology as outlined in AMP24, using base step trend models. Using this approach, we have modelled the updated forecast by opex category, capturing any new information pertinent to:

- **The base workings** – The base is forecast by analysing expenditure in the selected base year (RY24), identifying and removing any items that could be considered 'one-off', such as inspection trials or rollover from the previous year.
- **The step workings** – These can be multi-year changes signalling a need for upward or downward movement from the base – for example, the introduction of a new inspection.
- **The trend workings** – These are adjustments to the profile, signalling trend changes such as an increasing network size.

In summary, total operational expenditure has increased by 5% from AMP24 (RY25–RY34) to AMP25 (RY26–RY35) over the relative 10-year period. While preventive and corrective maintenance forecasts have dropped, vegetation management, reactive maintenance, and non-network have all increased.

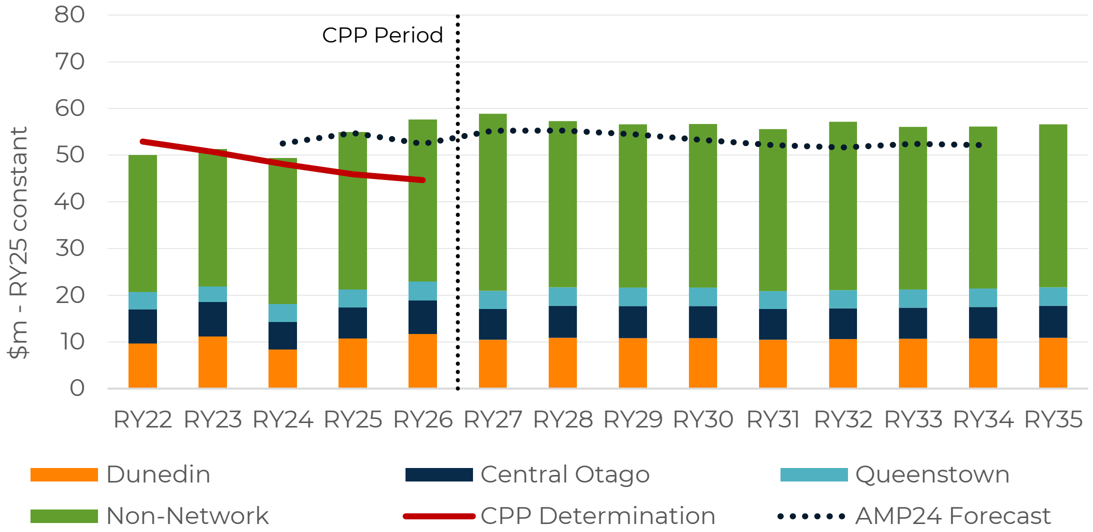
Preventive maintenance is down 6% from AMP24 (RY25–RY34) to AMP25 (RY26–RY35), over the relative 10-year period. This is owing to a downward adjustment in the base, a reduction in the expected cost of our new overhead inspection programme alongside efficiencies gained by bringing multiple asset type inspections into a single overhead inspection programme, and the removal of funding previously earmarked for lidar surveys.

Corrective maintenance is down 17% from AMP24 (RY25–RY34) to AMP25 (RY26–RY35), over the relative 10-year period. This is owing to a reduction in the base and the reforecast of the consumer pole programme.

Vegetation management is up 29% from AMP24 (RY25–RY34) to AMP25 (RY26–RY35), over the relative 10-year period. This is owing to the assessed impact of regulatory changes and the allowance for enhanced data and tools to enable more effective vegetation management.

Non-network opex is up by 13% from AMP24 RY25–RY34) to AMP25 (RY26–RY35), over the relative 10-year period. This is owing mainly to an intensified digital enablement plan incorporating technology upgrades and intelligent network support, alongside a step change in resource requirements. Figure 1-8 reflects RY25 opex forecasts as at November 2024. However, our February 2025 update to Schedule 11b reflects lower levels of RY25 opex largely resulting from the deferral of new network and technology based initiatives pending negotiation and execution of commercial arrangements.

Figure 1-8: 10-year opex forecast by sub-network, Total ($m)



1.2.12. Delivery of our plan

To deliver planned maintenance, reactive maintenance, vegetation management, and capital projects, Aurora Energy operates an external contracting model. Field Service Agreements (FSA) were re-tendered in 2023, with new contracting agreements for both field services and vegetation services in place since 1 April 2024.

Our key service providers are:

- Delta Utility Services (Delta)
- ElectroNet Services (ElectroNet)
- Unison Contracting Services (Unison)
- Asplundh

These service arrangements give us access to the skilled resources required to deliver our programme of work through the CPP and beyond, while providing a framework for improved service delivery and efficiency. They also allow for the increased use of competitive tendering and will reduce the risk of under-delivery and help ensure we receive efficient and market-tested pricing.

Our Service Delivery team oversees all network expenditure and contracts, ensuring adherence to rigorous technical standards for safety, quality, and cost-effectiveness. These standards are subject to ongoing review and improvement.

As we progress through the CPP period and make progress regarding the backlog on safety critical fleets, while simultaneously maturing our view of asset health and risk, we flex our plan to meet the overall CPP objective of safety first. In doing this, we consult with our service providers regarding any implications on resourcing with respect to work type, for example.

We do not see deliverability as a reason to deliberately constrain our forecasts and plans, which are linked to safety and consumer outcomes. Rather, to ensure resources are available to deliver work on the network, we communicate forecasts of future work by type to provide visibility of the work pipeline to our field service providers so that resourcing planning can be proactively managed.

Cost escalation being greater than expected has an impact on longer term forecasts. While the quantity of work is generally reducing, this is not leading to a corresponding reduction in expenditure.

Given the nature of Aurora Energy's external contracting model, it is vitally important that we provide a sustainable level of work to our external field service providers with sufficient visibility of future changes in the level and type of work. It is also important that field service providers react to this information by ensuring they have sufficient resources to deliver the different types of work.

To further help ensure availability of sufficient resources, recognising that changes in service provider resources are often long-term initiatives, we have sought to structure an asset management plan that, where possible, has small consistent changes in work types and volumes over time, as opposed to large changes on a year-to-year basis.

A

DELIVERING FOR CONSUMERS

CHAPTER 2
WHO WE ARE

Aurora Energy is one of the largest electricity networks in New Zealand. We own and manage the network that delivers electricity to some of the fastest growing areas and over the most diverse terrain in the South Island.

2.1. WHO IS AURORA ENERGY?

We take the power from Transpower's national grid to power your home, business and the wider community, and deliver a safe, reliable and sustainable electricity supply to more than 200,000 people across Dunedin, Central Otago & Wānaka, and Queenstown.

Climate change and the need to reduce carbon emissions are changing how we all think about energy. Our network must be able to support our rapidly growing region and the growth of electrification. We are focused on planning for the future to ensure our network has the capacity to support consumers' changing needs and create a future where choice is central to how they use energy – whether to charge electric vehicles or connect solar to homes or businesses. We also want to help consumers understand how to lower their overall energy costs by actively managing how they use electricity at critical times of the day.

Aurora Energy is at the centre of a shared, dynamic and flexible energy system, driven by how we collaborate with our partners. Together with our FSA partners we are delivering a large work programme and spending $560 million across the region to ensure the future resilience of the area, as well as upgrading existing assets. Our plans align with council spatial plans, support our stakeholders, and position our communities for the future.

We know a sustainable, secure and efficient energy supply is important to consumers – and it's important to us too. We acknowledge the impact our organisation has on our surroundings, and we recognise our responsibility to deliver for consumers' social, environmental and economic interests. We respect iwi values regarding how natural resources should be managed and the impact Aurora Energy has on the environment, by honouring Te Tiriti o Waitangi.

We are there for consumers 24/7, delivering power through our network over 99% of the time. Like most electricity distribution businesses (EDBs), we operate an interposed model. This means our lines charges are bundled with other charges that make up a consumer's power bill.

Our lines charges recover the direct costs of distributing electricity across our network (distribution prices), as well as other indirect costs (pass-through prices) including incentives, rates, regulatory levies, and a levy for electricity transmission from Transpower's national grid.

Currently, close to 20 retailers sell electricity to end consumers on our network. Generally, retailers are responsible for collecting revenue on our behalf and maintaining direct contractual relationships with end consumers.

2.1.1. Our ownership & governance

Aurora Energy Limited is a wholly owned subsidiary of Dunedin City Holdings Limited, which is owned by the Dunedin City Council. Our principal regulators are the Commerce Commission and the Electricity Authority.

BOARD OF DIRECTORS

The Aurora Energy Board provides strategic guidance, monitors the effectiveness of our management, and is accountable to shareholders for the company's performance. The Board is responsible for enabling the organisation to secure the resources necessary to implement its programmes and services so it can accomplish its goals and meet the needs of stakeholders. It has established policies to safeguard and guide the use of resources and assets, including appropriate management of risk.

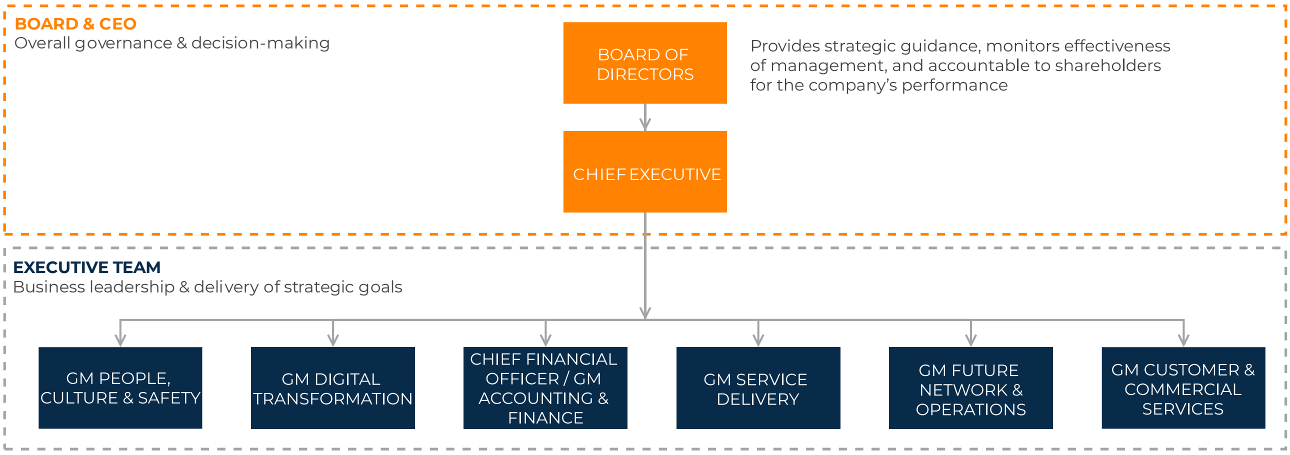
The Board reviews and approves the AMP to ensure it meets all regulatory requirements. This AMP was approved by Aurora Energy's Board on 28 March 2025.

EXECUTIVE LEADERSHIP TEAM

Like most organisations, support is provided by a group of general managers (GMs), each responsible for a functional area of the organisation. Core responsibilities of the executive leadership team include delivering the organisation's strategic goals and providing advice and leadership to the wider business. The structure of our executive leadership team is illustrated by Figure 2-1.

Note that in parallel with the drafting of this AMP, we have been progressing an organisational change process, which has had an impact on the structure of the Executive Leadership Team.

Figure 2-1: Aurora Energy Executive Leadership Team



2.1.2. Asset management responsibility

Our business groups work collaboratively to ensure the overall delivery of network services that meet consumers' needs. The day-to-day management of our network is primarily provided through the following functions:

- Asset Management and Planning
- Operations and Network Performance
- Works Programming and Delivery

More details of the roles and responsibilities for asset management are provided in Chapter 6.

2.2. OUR BUSINESS STRATEGIC FOCUS AREAS & CORPORATE VALUES

The electricity industry is changing and so are the needs of consumers. Our network must be able to support a rapidly growing region, the diversification of the industry, and the continued strong growth of electrification as a key driver of decarbonisation in New Zealand.

The core function of our business is to deliver electricity safely, reliably, and affordably to consumers – now and into the future. Our strategic focus areas are the foundation for enabling continual business improvements so we can achieve our purpose: *Enabling the energy future of our communities*.

Our purpose, vision, strategic focus areas, and company values are outlined on the next page.

OUR PURPOSE

ENABLING THE ENERGY FUTURE OF OUR COMMUNITIES

OUR VISION

To deliver our purpose by creating a positive work environment that enables our people to drive innovation to deliver a sustainable and resilient electricity distribution network that meets the needs of customers and our shareholder, now and in the future.

OUR STRATEGIC FOCUS AREAS

Focus Areas	Approach	Outcomes
OUR PEOPLE	Supporting the development of our people and creating a culture that attracts the best talent	**An employer of choice** We're a leading organisation, recognised for our people centric culture, our flexible, inclusive and diverse work environment and our innovation and future focused thinking
FUTURE NETWORK	Investing in our network and operations to meet the changing electricity demands of customers	**A smart & adaptive network with real-time operations** We have a network that is maintained in good health at lowest whole of lifecycle asset cost. Network transformation delivers intelligent and adaptive operational management including integration of distributed energy resources to optimise the cost of electricity distribution for customers
CUSTOMERS & COMMUNITY	Focusing on what matters to customers and partnering with local business and stakeholders to support regional growth	**Respected in our communities for the service we provide** We are respected by our communities and partners and our brand is synonymous with providing fair value, a reliable service and with trust and credibility
DIGITAL ENABLEMENT	Applying technology, innovation and new skills to drive digital transformation and productivity across the organisation	**A business operating "digital first"** Our enterprise processes, network operations and customer service interactions are digitally enabled, and artificial intelligence/machine learning reduces low value tasks, driving improved productivity, enhancing decision making and insights and delivering value to customers
DELIVERING VALUE	Demonstrably optimising future value for both customers and our shareholder	**We maintain our licence to operate** Our continued licence to operate comes from being the best at what we do, ensuring the long-term financial viability of the business, leading and adapting to changing circumstances and demonstrably providing value to our shareholder and customers

OUR VALUES

SAFETY FIRST
Safety first means people come first!

SOLUTIONS FOCUSED
We step up, and own it!

ONE TEAM
We're better together!

LEARNING & INNOVATION
We love light bulb moments!

INTEGRITY
We do the right thing!

Note that in parallel with the drafting of this AMP, we have been progressing an update to our Business Strategy. The implementation of the updated strategy, including the review of asset management objectives against the new business strategy, will be worked through ahead of the next AMP.

Aurora Energy's Asset Management Policy aligns the foundational business strategy to the operational asset management system. It instigates our key objectives of safety, solutions-focused, and doing the right work at the right time for the right cost, to support the future growth and wellbeing of our communities.

2.3. OUR INVESTMENT DRIVERS

This section gives an overview of the key factors that have had an impact on our approach to asset management over the planning period. The focus for Aurora Energy over the last four years has been on improving safety. And while this focus remains, we are also starting to focus on moving from a traditional network to a smart network, where the driver is decarbonisation and supporting New Zealand's transition to electrification.

CHALLENGES WE FACE

Table 2-1 outlines the key challenges that impact the Aurora Energy network.

Table 2-1: Challenges

Challenge	Description
Asset safety	Prior to our current CPP period we experienced a lengthy period of underinvestment, which led to deteriorating safety due to poor asset condition. Our expenditure over the last four years has been aimed at addressing the backlog. We are focusing a lot of effort on maturing our asset management practices so that we can continue to mature our understanding of asset health and emerging asset safety concerns – including evaluating and determining optimised, evidence-based investment in renewals.
Ageing assets	Over more than a century, our infrastructure has developed alongside population/regional growth. Large portions of our network are due for renewal. Over the next 10 years we need to make significant investments to maintain and renew our distribution network, while also preparing for the changing energy needs of consumers. While our assets are ageing, through our maturing asset management practices, we are progressing towards a condition-based renewal plan, enabling optimisation of asset lives and targeted investment to realise safety objectives.
Growth & demand	Future planning is challenging due to the unknown extent and pace of electrification – a key driver of step change in electricity demand – which creates an outlook of investment uncertainty. This is driven by decarbonisation on process heat (electric boilers) and transport (electric planes and ships), and the high uptake of EVs and PVs, combined with significant growth in residential/commercial/industrial consumers and large distributed generation. Tactical solutions can mitigate short- to medium-term challenges, but long-term solutions will require input from local councils, the community, Aurora Energy, and Transpower.
Customer Experience	We know that there are parts of our network where the reliability of our service is sub-optimal. While the focus of our CPP has been safety, we have realised some residual reliability benefits. We have also taken actions including establishing a 'Reliability Hotspot' programme and more generally implementing ongoing asset management improvements around root cause determination. These actions help us ensure performance and failures are well understood and enable us to make targeted improvements and investments to address issues that would otherwise potentially reoccur.
Changing consumer expectations	As consumers adopt new technologies such as EVs with smart chargers and solar/battery systems, their needs are evolving. Consumers can now inject generation into the local network, creating a two-way power flow. We need to ensure our network delivers what they want and expect from us as their electricity provider, both now and into the future.
Regulatory & market changes	Aurora Energy is operating under a customised price-quality path (CPP) from 1 April 2021 until 31 March 2026. As part of this, the Commerce Commission has set a customised revenue allowance and quality standards for Aurora Energy, to enable us to fund the expenditure necessary to maintain a safe and reliable network.

Challenge	Description
Land access	Our ability to gain access to existing assets or obtain land for new assets is critical to timely and effective asset interventions. We aim to minimise (as far as practical) the amount of land access required as changes in access requirements can cause additional expense and delay in the delivery of new assets.
Climate change	Extreme weather conditions associated with climate change (e.g., wind, drought, flooding or snowstorms) can have a significant impact on the condition, reliability and performance of our assets. The planned expenditure in our AMP aims to make our assets and network more resilient. We have also been continuing to mature our business continuity and emergency response framework to ensure we are prepared for major events.
Environmental impact	We know a sustainable, secure and efficient energy supply is important to consumers and we are continuing to prepare the network for decarbonisation. We continue to assess and measure our greenhouse gas (GHG) emissions to build on the baseline work undertaken in FY21.
Technology changes	Aurora Energy enables the uptake of new technologies by making sure our network planning allows for the changing ways consumers are using electricity. As a business, we utilise new technologies to improve our network and its performance through digital enablement.
Asset management capability	As our processes mature and we implement an asset management software solution (AMSS), we will have improved data to better inform decision-making and planning. We are progressing toward our goal of having an ISO 55001-aligned asset management system.
Retaining our talent	Attracting and retaining talent remains a priority in a competitive and evolving sector, alongside future workforce planning to ensure Aurora Energy can continue to deliver to a high standard and be an employer of choice.

PRIORITY INVESTMENT DRIVERS

Based on the key challenges outlined above, we have developed our priority investment drivers linked back to our five Strategic Focus Areas.

Our investment drivers underpin the expenditure we are forecasting over the next 10 years, as covered by this AMP.

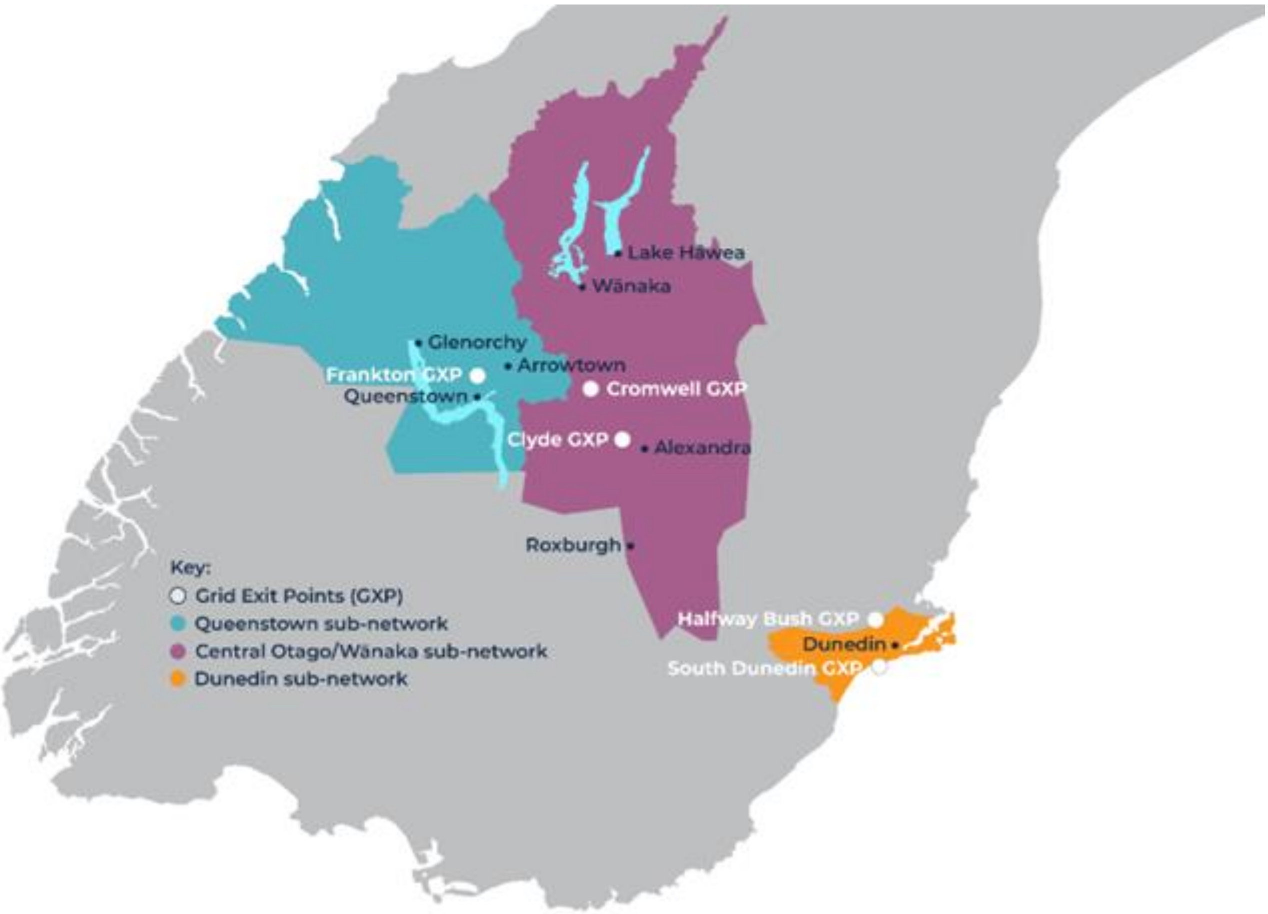
Table 2-2: Priority investment drivers

Tactical Pillar	Investment driver	Description
Our People	Future workforce and organisational design planning	Our people are critical to the success of our organisation, now and into the future. In the changing landscape of our industry, we recognise the need to reflect readiness in the skills and capability of our future workforce.
Future Network	Growth and demand	Uncertainty around how the electricity industry will evolve to meet changing energy needs means a joint approach to long-term planning with communities, councils and Transpower is essential. Resilience against increasingly extreme weather events is also crucial to ensuring a reliable electricity supply.
Customers & Community	Changing consumer expectations	Listening to what consumers want from an electricity network will ensure we meet their needs. This is increasingly important as people change the way they use electricity in response to new technologies and the drive to decrease carbon emissions.
Digital Enablement	Technology changes	In a period of rapid technological advancement, there are promising opportunities posed by the digital transition and new ways of working, including the development of artificial intelligence to enhance productivity and efficiency. We are working to a multi-year digital enablement programme.
Delivering Value	Asset management capability	Maturing asset management practices, including evidence-based renewal planning and targeted maintenance strategies through enhanced condition assessment, are enabling us to reduce backlogs of poor condition assets. This is crucial in order to stabilise the overall health of our asset fleets and improve network reliability performance.

CHAPTER 3
OUR NETWORK

Our network distributes electricity to homes, farms, ports, schools, businesses and local utilities across three non-contiguous sub-networks in Dunedin, Central Otago & Wānaka, and Queenstown. Each sub-network is distinct and has its own power supply requirements and different types of consumers. Aurora Energy continues to improve the network to meet consumers' needs in their decarbonisation journey and enable their uptake of new technologies.

Figure 3-1: Our network and the communities we supply



3.1. NETWORK OVERVIEW

3.1.1. Transpower grid exit points

Aurora Energy's network takes electricity from the national grid through five grid exit points (GXPs). These GXPs are the interface between Transpower's transmission network and our distribution network. There are two GXPs for our Dunedin sub-network, two for our Central Otago & Wānaka sub-network, and one for our Queenstown sub-network. The numbers of customers distributed across these GXPs are shown in Table 3-1.

There is redundancy built into the GXPs through duplication of equipment, which means the system can continue to function after the failure of one component.

Table 3-1: GXPs and sub-networks

Sub-network	GXP	Number of customers	% of customers
Dunedin	Halfway Bush	36,425	37
	South Dunedin	21,756	22
Central Otago & Wānaka	Clyde	8,043	8
	Cromwell	16,482	17
Queenstown	Frankton	15,624	16

Figure 3-2: GXPs and transmission lines (map from Transpower)

3.1.2. Network configuration

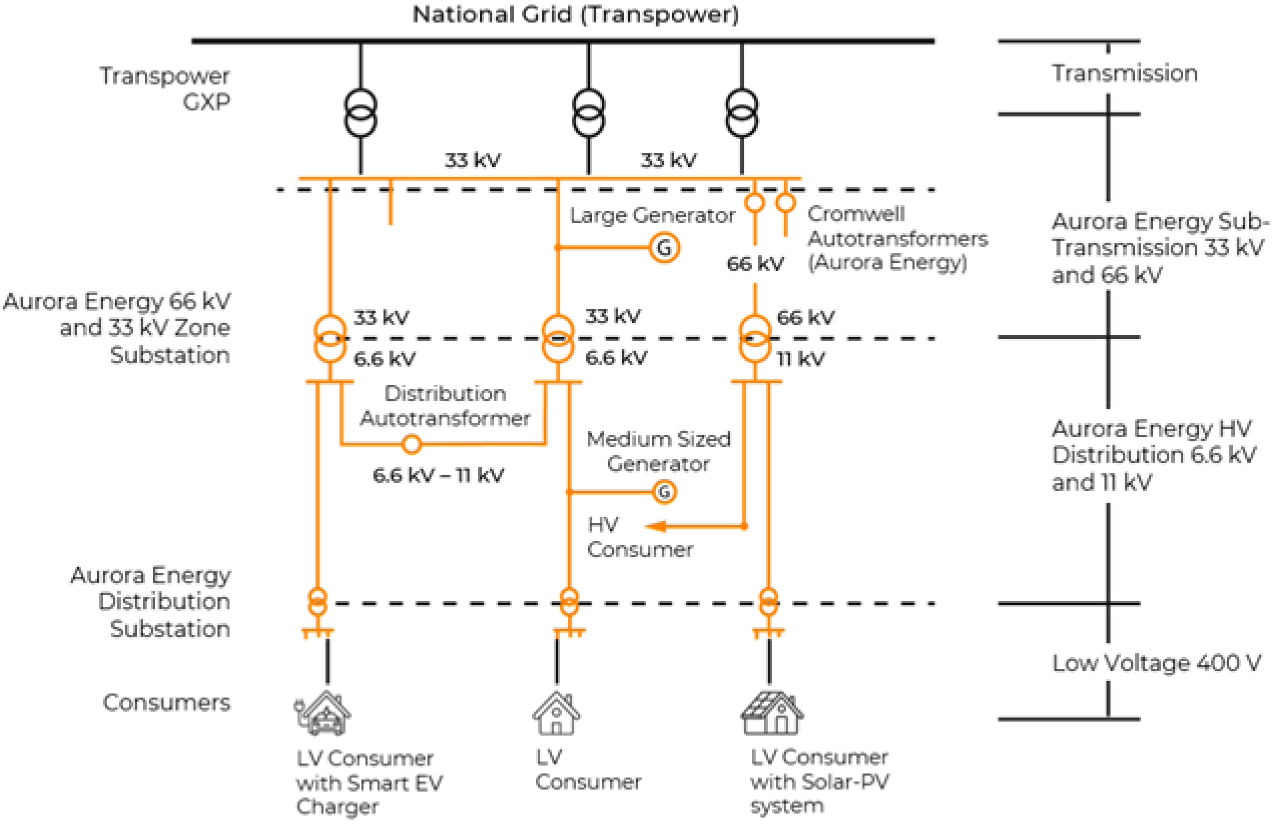
Our network is hierarchical in nature, with lines and cables operating at three distinct voltage ranges:

- **Subtransmission:** Operating at 66 kV (minority) and 33 kV
- **Distribution:** Generally operating at 11 kV in Clyde and 6.6 kV in Dunedin
- **Low voltage (LV):** Operating at 400 V three phase or 230 V single phase

Our subtransmission network conveys electricity from Transpower's GXP sites to our zone substations that supply our distribution network, which in turn supplies our low voltage network. Our subtransmission network has two operating voltages, 66 kV and 33 kV. We use 66 kV where there are long distances between GXPs and zone substations, as this reduces line losses. Currently, we only use 66 kV in parts of the Central Otago & Wānaka sub-network, while the rest of the subtransmission network is operating at 33 kV.

In the low voltage network, an increasing number of consumers are adopting new technologies such as solar or solar-battery systems and electric vehicles (EVs). The Central Otago & Wānaka and Queenstown sub-networks have more solar or solar-battery systems than the Dunedin sub-network. However, there are more EVs in the Dunedin sub-network. We anticipate that the rising adoption trend will continue as more Kiwis contribute toward NZ's net-zero goal.

Figure 3-3: Aurora Energy network connection to the national grid



3.1.3. Network assets

Our total network asset quantities are summarised in Table 3-2.

Table 3-2: Network asset quantities

	33 kV & 66 kV	6.6 kV & 11 kV	400 V & 230 V	Total
Zone substations	–	–	–	39
Distribution transformers	–	–	–	7,300
Consumer connections	–	–	–	98,330
Overhead network	522 km	2,278 km	1,025 km	3,825 km
Underground network	99 km	1,219 km	1,164 km	2,482 km

GXP sites are owned by Transpower, but Aurora Energy has some equipment co-located at each GXP. A list of this equipment is shown in Table 3-3.

Table 3-3: Selected Aurora Energy assets at GXPs

Asset	Halfway Bush	South Dunedin	Frankton	Cromwell
Ripple control plants	2	1	1	–
Buildings	2	1	–	1
Protection relays	Yes	Yes	Yes	Yes
SCADA and metering	Yes	Yes	Yes	Yes
Structures and air break switches	Yes	Yes	Yes	Yes
Others	33 kV cable gassing bank	33 kV cable oil reservoirs		Auto-transformers: 2×30 MVA 33/66 kV 1×50 MVA 33/66 kV

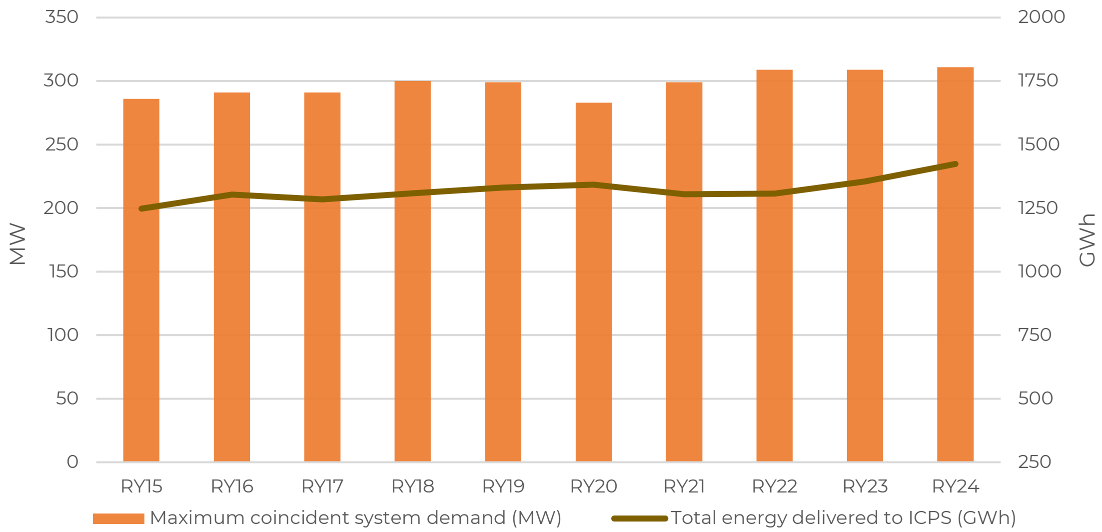
3.1.4. Total system peak demand & energy throughput

The total system peak demand in the last three years had a modest increase with an average of 309 MW. However, electricity delivered has progressively increased to 1424 GWh in RY24, with an average of 1362 GWh. This indicates that the network is growing to meet consumers' needs.

Much of this growth is in Wānaka and Queenstown, while the demand in Central Otago (Clyde GXP) is steady. In contrast, we have seen a decline in peak demand in Dunedin this year.

Figure 3-4 shows the electricity delivered to the ICPs and system peak demand in the last ten years.

Figure 3-4: Energy throughput and GXP peak demand



The maximum demand and energy throughput for each sub-network last year is shown in Table 3-4, while Table 3-5 shows this year's GXP peak demand with zone transformer capacity and the numbers of zone substations.

Table 3-4: Maximum demand and energy throughput by sub-network

Sub-network	Maximum demand (MW)	Energy throughput (GWh)
Dunedin	186	813
Central Otago & Wānaka	67	329
Queenstown	75	281

Table 3-5: Peak demand and firm capacity

GXP	Sub-network	Maximum demand (MW)	Firm capacity (MW)	Zone transformer capacity (MW)	Zone substations (Qty)
Halfway Bush	Dunedin	117	131	353	12
South Dunedin		72	108	270	6
Cromwell	Central Otago & Wānaka	54	58	141	6
Clyde		19	27	54	7
Frankton	Queenstown	82	76	171	8

3.1.5. Distributed generation on our network

Distributed generation (DG) schemes have the potential to make a significant contribution toward meeting the electricity requirements of local consumers and support Aotearoa New Zealand's decarbonisation goals.

DG supports our network by reducing peak demand, enhancing security of supply, and increasing the efficiency and economy of the network's operation. However, DG can also give rise to adverse effects on the network, including harmonic distortion, localised congestion, voltage instability, safety issues, and network reliability issues. Accordingly, care is required when approving new distributed generation connections. As such, we continually improve our small-scale and large-scale DG application processes.

Guidelines and application information for the connection of distributed generation are published on our website. For each proposal we consider the likely effect of the distributed generation on our network.

For small-scale DG (less than 10 kW) applications, we have aligned our process with the Electricity Engineers' Association's *Interim Guide for Connection of Small-Scale Inverter-Based Distributed Generation*. Small-scale DG typically consists of residential solar or solar-battery systems. For large-scale DG (greater than 10 kW), depending on the size, it is necessary to assess the impact of the generation on the network.

The processing timeframe is outlined in Part 6 of the Electricity Industry Participation Code. Large-scale DG can range from residential solar or solar-battery systems to large generators such as hydro and wind.

As of 31 March 2024, the total installed generation capacity was 153 MW (49% of system maximum demand). Figure 3-5 shows the proportions of each type of generation.

Figure 3-5: Generation by type

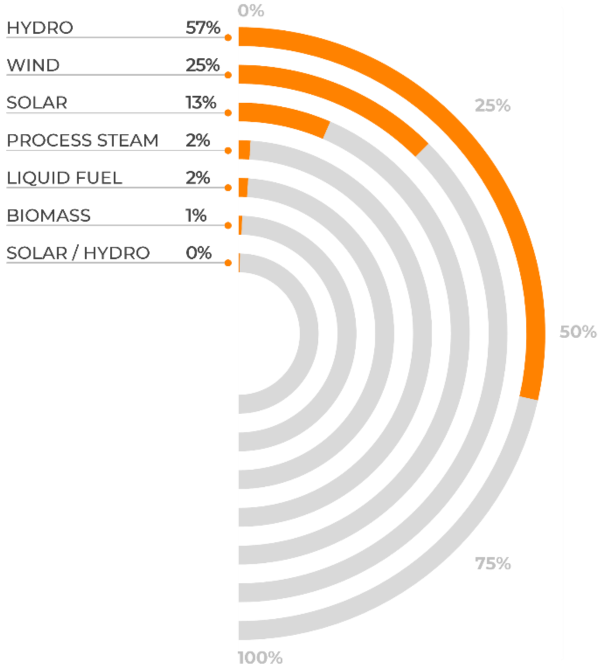
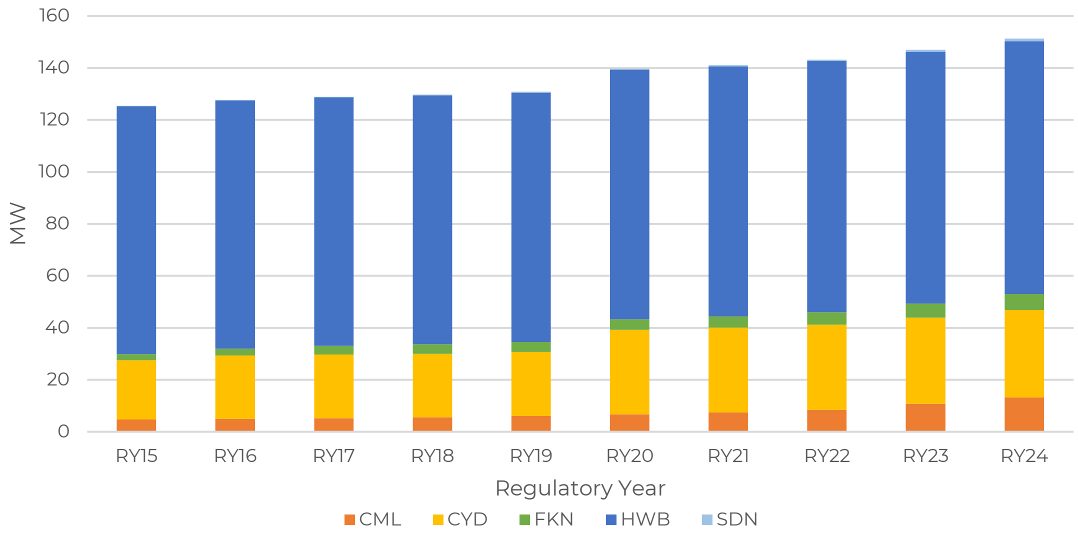


Table 3-6 gives a list of large, embedded generation (>1 MW) and Figure 3-6 shows the uptake of generation per GXP over 10 years.

Table 3-6: Large embedded generation (1 MW and above)

GXP	Name	Type	Capacity (MW)	Total per GXP
Halfway Bush	Waipori 33 kV, Waipori gen & Deepstream 1A, 2A	Hydro	53	95
	Waipori 33 kV – Mahinerangi	Wind	36	
	Ravensdown generation	Process steam	3	
	Container port (Port Otago)	Liquid fuel	2	
	DCC wastewater treatment plant	Biomass	1	
South Dunedin	–	–	–	–
Frankton	Wye Creek	Hydro	2	2
Clyde	Teviot Stations	Hydro	12	32
	Earnscleugh Stations	Hydro	8	
	Horseshoe Bend	Hydro	4	
	Fraser Generation	Hydro	3	
	Horseshoe Bend Wind	Wind	2	
	Talla Burn	Hydro	2	
Cromwell	Roaring Meg	Hydro	4	5
	Devon Dairy	Solar	1	

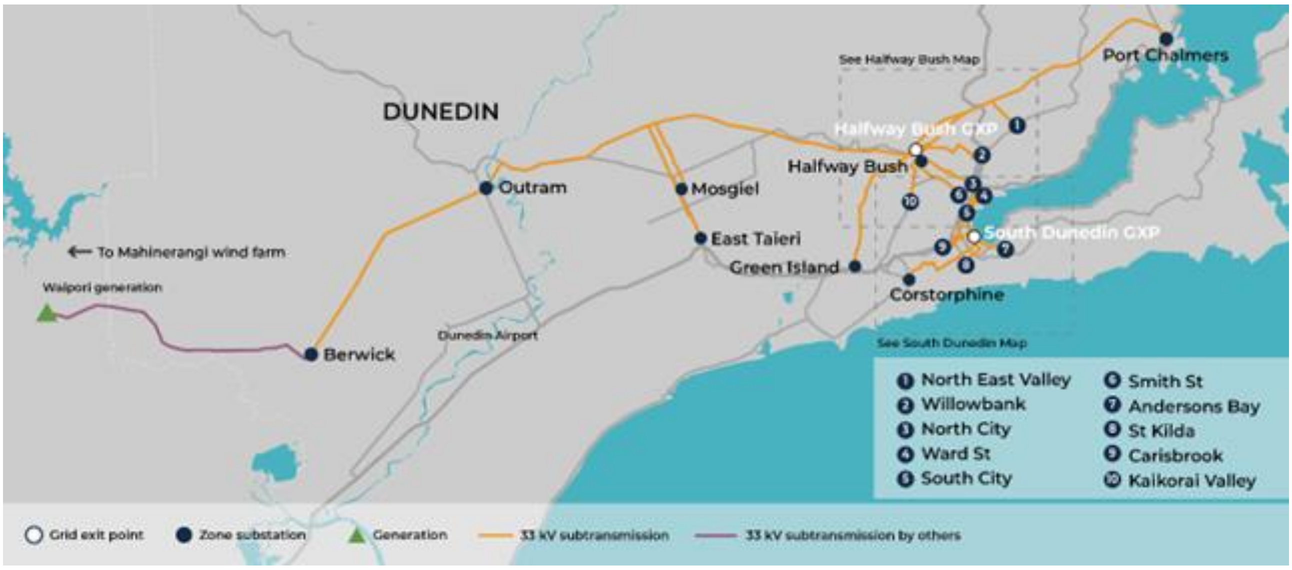
Figure 3-6: Total generation uptake per GXP



3.2. DUNEDIN SUB-NETWORK

Of the three sub-networks, Dunedin is the oldest. It includes two GXPs: Halfway Bush and South Dunedin. The development of this sub-network started in around 1910, although there were pockets of electricity supply before that. Until the 1970s, Dunedin was supplied entirely from the Halfway Bush GXP. Construction of the South Dunedin GXP resulted in the alteration of network supply points from some zone substations. The additional GXP provides some added resilience for the city's supply; however, it does not provide the capability to transfer significant load between GXPs.

Figure 3-7: Dunedin sub-network



As shown in Figure 3-8 and Figure 3-9, most of Dunedin's 33 kV subtransmission is radial, with each zone substation fed directly from its GXP.

To attain N-1 security (where the loss of one circuit can be taken up by the remaining assets), each zone substation has two zone transformers (with the exception of Berwick and Outram), each with a designated overhead line or underground cable directly from the GXP.

In our ten-year plan we propose to create a subtransmission ring configuration to increase security of supply at the Dunedin central business district (CBD). This will give us the capability to transfer significant load between GXPs.

Dunedin's distribution network voltage is predominantly 6.6 kV, with some 11 kV in zone substations such as Outram, East Taieri, Mosgiel, and Port Chalmers. Autotransformers have been installed to link the 6.6 kV network with the 11 kV network.

The distribution network is made up of overhead lines and underground cables, with the CBD mostly comprising underground cables.

Halfway Bush GXP has a large embedded generation plant (Waipori) that supplies 30% of the GXP's peak demand. Waipori has a total generation capacity of 95 MW (hydro and wind). The South Dunedin GXP has no large embedded generation.

Figure 3-8: Halfway Bush subtransmission and zone substations

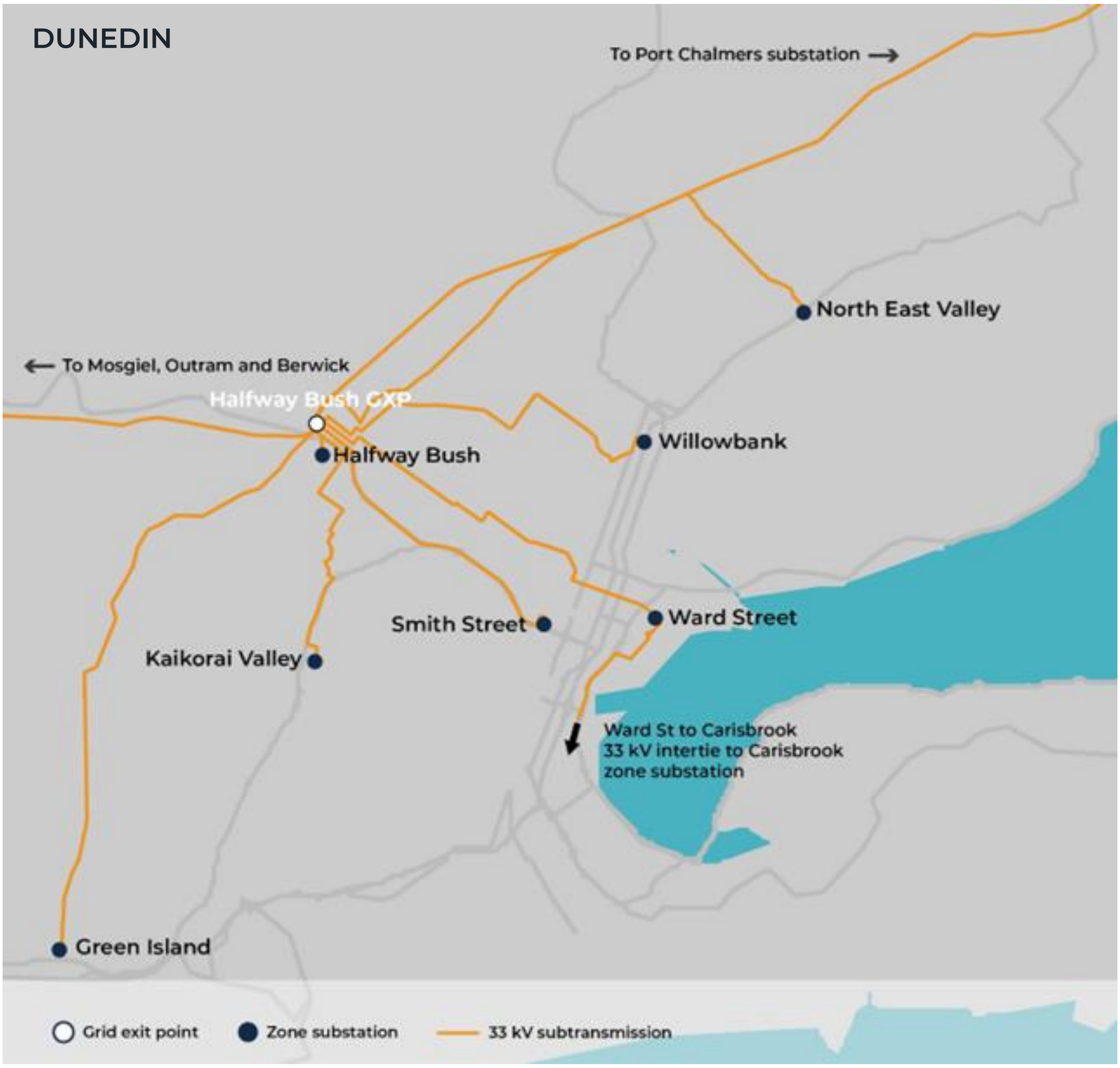
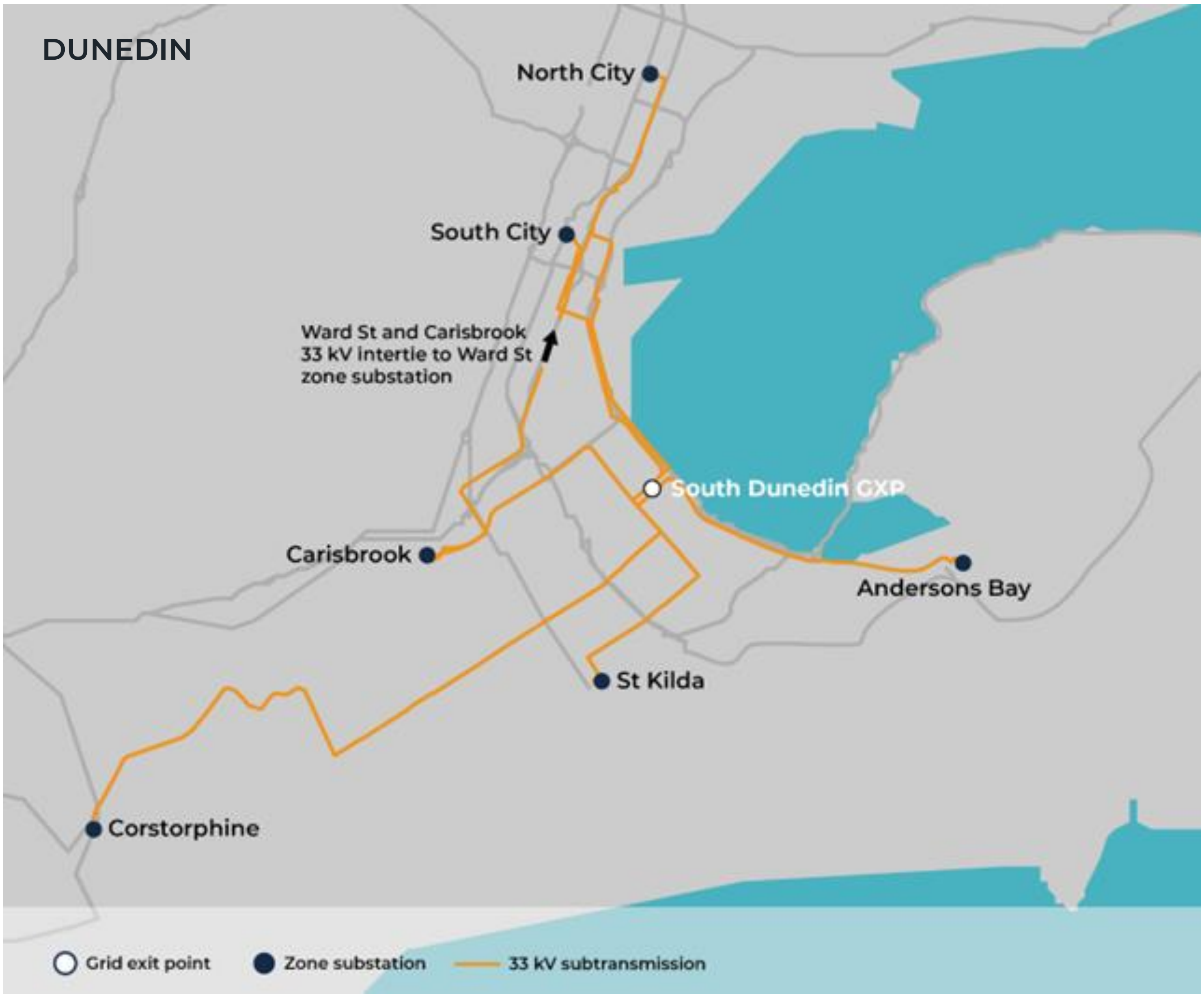


Figure 3-9: South Dunedin subtransmission and zone substations



3.2.1. Network assets

Our total network asset quantities on the Dunedin sub-network are summarised in Table 3-7.

Table 3-7: Summary of Dunedin sub-network assets

	33 kV & 66 kV	6.6 kV & 11 kV	400 V & 230 V	Total
Zone substations	–	–	–	18
Distribution transformers	–	–	–	2700
Consumer connections	–	–	–	58,181
Overhead network	143 km	724 km	807 km	1,674 km
Underground network	67 km	334 km	318 km	719 km

3.2.2. Dunedin sub-network load

The Dunedin load is a mixture of residential, commercial, and industrial. Due to the climate, residential and commercial heating contribute significantly to the network peak load, which follows an expected pattern of morning and early evening peaks.

These peaks are greater on colder winter days. Load control (predominately of domestic hot water storage systems) is used to reduce these peaks. A small amount of dairy farming on the Taieri Plains gives rise to irrigation and milking loads during summer, especially on the Berwick zone substation.

3.2.3. Key consumers

Our key consumers for the Dunedin sub-network are summarised in Table 3-8.

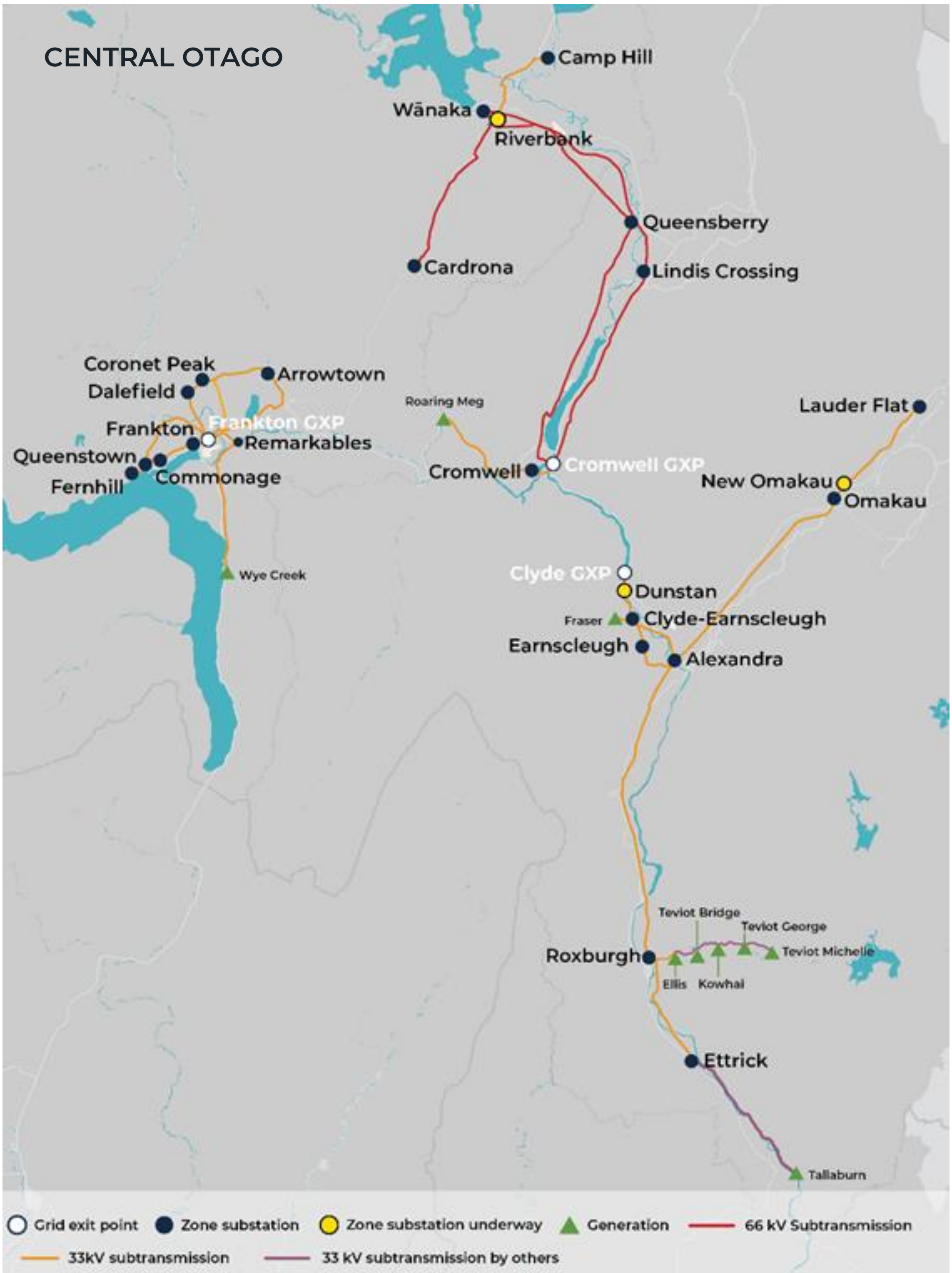
Table 3-8: Dunedin sub-network consumers

Consumer	Description
Dunedin City Council	The combined load of all the Dunedin City Council-operated sites is significant. The most important sites are those associated with water and wastewater pumping and treatment. Long-term failure of supply to these sites can cause significant social and environmental impacts. The larger, more critical sites have alternative feeds from multiple zone substations, and the Council has installed backup generation for added security. These sites are a priority for restoration of supply in the case of any natural disaster, most likely in cooperation with Civil Defence Emergency Management. A growing population would require expanding or new utilities, which will have new electricity connections and supply requirements.
Dunedin Hospital	The Dunedin Hospital is a significant and critical load which is supplied via two feeders from the North City zone substation. An internally operated changeover arrangement enables switching of supply between these feeders and/or backup generators as required. An alternative direct feed from the Ward Street zone substation is available should both North City feeders fail. The proposed new Dunedin Hospital will have two buildings: the Outpatient building, which will draw a 2 MVA load; and the Inpatient building, which will draw a 7 MVA load. Both buildings require N-1 security. We plan to supply the Outpatient Building with N-1 security from our North City zone substation and the Inpatient Building with N-1 security from our Ward Street zone substation. The buildings are proposed to be electrically interconnected as part of the hospital plans, thus providing the capability to supply the total load of the hospital from either zone substation.
University of Otago	The University of Otago operates a number of buildings in the northern part of Dunedin City. University load – and load from surrounding student accommodation – reduces over the university holiday periods. There are a number of alternate supply possibilities into the university area from the North City, Ward Street, Willowbank, and Smith Street zone substations.
Port Otago	The port is a critical business for the Otago area. If the port were not able to operate for any reason, this would have significant financial and social implications for the city and the region. In addition, power outages are extremely undesirable from a business perspective due to the need to turn around shipping traffic in a timely manner. Electricity is also required for refrigerated containers at the port, to protect perishable goods. Port Otago is fed via two separate feeders from the Port Chalmers zone substation, with a manual changeover arrangement. The port will be a critical customer should any significant natural disaster event occur anywhere in the southern part of the South Island. It will likely be a key facility for transportation of emergency equipment and supplies. Electrification of ships (e.g., cruise ships) requires a substantial amount of electricity. Typically, vessels will be supplied through shore power substations that provide them with electricity when they are docked at ports. This development introduces uncertainty to network investments, as these are large loads that will require new assets to be built with unknown demand and development schedules.
Dunedin Airport	Loss of supply to Dunedin Airport has both commercial and air traffic safety implications. The airport operates a standby generator and has an auto-changeover system that switches between a feeder from the Outram zone substation and a feeder from the Berwick zone substation. As with the port, the airport will likely become a key facility in times of natural disaster. Electrification of planes, like ships, will require large amounts of electricity, and presents similar investment uncertainty.

3.3. CENTRAL OTAGO & WĀNAKA SUB-NETWORK

The Central Otago & Wānaka sub-network area encompasses two territorial authorities: Queenstown Lake District Council and Central Otago District Council. This sub-network was mostly developed after 1960, although it includes pockets of older assets. The two parts of the sub-network are geographically distinct, with no interconnection. This sub-network has the most extreme climate on mainland New Zealand, which has implications for electricity supply. The climate is characterised by hot summers, cold dry winters, low air humidity, and a predominantly dry westerly wind.

Figure 3-10: Central Otago & Wānaka sub-network



3.3.1. Wānaka

The two Cromwell GXP transformers have three windings: the 220 kV side takes supply from the national grid; the 110 kV side supplies the Frankton GXP; and the 33 kV side supplies Wānaka. The network is unique in that it supplies two separate areas with minimal interconnection: Cromwell and Upper Clutha. Cromwell township is fed from our Cromwell substation, which is close to the GXP and is supplied by two 33 kV subtransmission circuits. The Upper Clutha area encompasses Wānaka, Cardrona, and Hāwea.

Since the Upper Clutha area is located 55 km from the GXP, it is necessary to transform the 33 kV voltage from the GXP to 66 kV using two autotransformers (33/66 kV) and supply the large electricity demand with 66 kV voltage. This is the only part of the Aurora Energy network that has 66 kV subtransmission. Due to significant demand growth in the Upper Clutha area, we are installing a third autotransformer (33/66 kV).

Another distinctive feature of this area is the Wānaka zone substation, which has two three-winding transformers where the 11 kV side supplies the Wānaka area and the 33 kV side supplies Camp Hill zone substation via a single 33 kV overhead line.

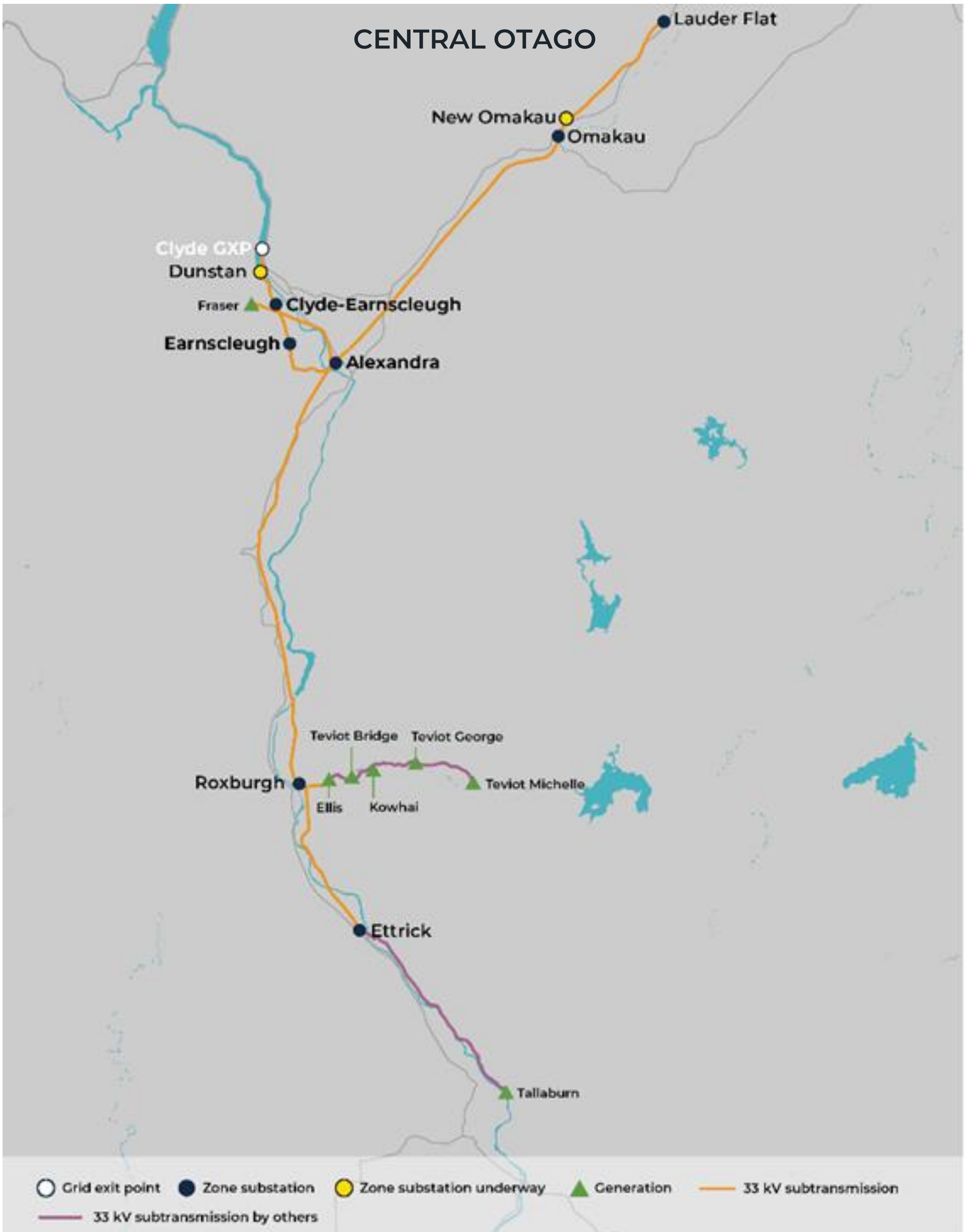
Figure 3-11: Wānaka subtransmission and zone substation

3.3.2. Clyde

The Alexandra, Clyde, Manuherekia, Ida Valley, and Teviot Valley areas are supplied via two 33 kV subtransmission circuits connected to the Clyde GXP. The GXP is inside the Clyde Dam. Most of the electricity demand in the Clyde area is supplied from distributed hydro generation sites at Teviot, Ettrick, and Earnscleugh. The subtransmission plays an important role in injecting excess generation into the national grid at the Clyde GXP.

Two parallel 33 kV lines run between the Clyde GXP and Alexandra, and then on to Roxburgh, which connects 32 MW of embedded generation capacity. From Roxburgh, a single 33 kV line supplies Ettrick. Omakau and Lauder Flat, to the north-east of Alexandra, are supplied by a single 33 kV line from the Alexandra 33 kV outdoor switchboard. The distribution network voltage is 11 kV, with the exception of parts of Clyde and Earnscleugh, which are supplied at 6.6 kV.

Figure 3-12: Clyde subtransmission and zone substation



3.3.3. Central Otago & Wānaka load

The Wānaka network load is typically residential subdivisions and commercial developments. Wānaka also hosts two ski fields, an airport, and a number of irrigation loads. The Wānaka network load peaks in the winter period, but the zone substations at Lindis Crossing, Queensberry, and Camp Hill are summer peaking.

The Clyde load is predominantly residential and irrigation. However, the load is smoothed by the large number of embedded generators, which most of the time are supplying the load and exporting to the National Grid. Except for Alexandra, the maximum demand of all zone substations occurs during the summer period.

3.3.4. Network assets

Our total network asset quantities on the Central Otago & Wānaka sub-network are summarised in Table 3-9.

Table 3-9: Summary of Central Otago & Wānaka sub-network assets

	33 kV & 66 kV	6.6 kV & 11 kV	400 V & 230 V	Total
Zone substations	–	–	–	13
Distribution transformers	–	–	–	3,300
Consumer connections	–	–	–	24,525
Overhead network	309 km	1,273 km	174 km	1,756 km
Underground network	10 km	589 km	525 km	1,124 km

3.3.5. Key consumers

Our key consumers for the Central Otago & Wānaka sub-network are summarised in Table 3-10.

Table 3-10: Central Otago & Wānaka sub-network consumers

Consumer	Description
QLDC and CODC local councils	The total load of the Central Otago District Council (CODC) and Queenstown Lakes District Council (QLDC) sites is significant. As in Dunedin, the most important loads are those associated with water and wastewater pumping and treatment. Most of the CODC and QLDC sites have alternative HV feeds that are manually switched as required. These sites are a priority for restoration of supply for any natural disaster, most likely in co-operation with Civil Defence Emergency Management. Population growth would require expanding or new utilities (WWTP and WTP), which would have new electricity connections and supply requirements.
Cardrona, Treble Cone Ski Fields	Load at these sites includes ski-lifts and snow-making machinery, as well as supply to related buildings. Ski-lift load is relatively consistent on days that the fields are open. Snow-making load occurs mainly on cold mornings early in the winter season but can run all day if natural snow is lacking and conditions are suitable for snowmaking. Peak loads generally occur during the July school holiday period when snowmaking overlaps with lift operations. All ski fields receive supply via single feeders over difficult terrain, with only limited backup. They are typically open for around 80 days per year, depending on snow conditions. Loss of electricity supply during a busy day – such as during school holidays – would cause significant financial loss. Load outside the ski season is generally very low.
Irrigation	The Cromwell and Clyde sub-networks have a significant amount of irrigation load. Irrigation demand is relatively consistent over the summer period but may be delayed by an unusually wet spring. At the end of the season irrigation load may reduce if it becomes too dry and sources of race water become limited. Irrigation demand differs in each location. In some areas water is pumped over relatively long distances and/or to relatively significant heights, resulting in high electrical load per irrigated land area. Other areas have lower demand as the pumping is from nearby surface ponds and races.

Consumer	Description
Wānaka Airport	In conjunction with tourism to the region, Wānaka Airport – like Dunedin Airport – is subject to commercial and air traffic safety implications in the event of loss of supply. The airport operates a standby generator for critical loads and peak demand management. A feeder from Frankton substation supplies the airport. The network is meshed, and a number of alternative supply options exist, including supply from Commonage substation in the unlikely event the Frankton substation is out of service. Electrification of planes will require large amounts of electricity and presents uncertainty to network investment, as such large loads will require new assets to be built with unknown demand and development schedules. A large fleet of rental cars is stationed near the airport. As these transition to EVs, growth in charging load is expected.
Tourism	Wānaka and Clyde are tourist destinations. Peak tourist days are in the winter period – in particular, the July School Holidays, when domestic and international tourists flock to the area. Airports, ski fields, accommodation, township centres, and activity areas are typically very busy during this period. Summer tourists also congregate in the area. Increasing visitor numbers will spur development of accommodation and hence increased electricity demand.

3.4. QUEENSTOWN SUB-NETWORK

The Frankton GXP is supplied via two 110 kV transmission circuits from the Cromwell GXP. The GXP transforms the voltage from 110 kV to 33 kV where Aurora Energy takes its supply.

The Frankton network conveys electricity to the Whakatipu basin and Queenstown, and has two main 33 kV subtransmission circuits: the Arrowtown circuit supplies the substations in the Whakatipu Basin; and the Queenstown circuit supplies Queenstown. All of the distribution network voltage is 11 kV.

Figure 3-13: Queenstown subtransmission and zone substation

3.4.1. Network assets

Our total network asset quantities on the Queenstown sub-network are summarised in Table 3-11.

Table 3-11: Summary of Queenstown sub-network assets

	33 kV & 66 kV	6.6 kV & 11 kV	400 V & 230 V	Total
Zone substations	–	–	–	8
Distribution transformers	–	–	–	1,300
Consumer connections	–	–	–	15,624
Overhead network	69 km	282 km	44 km	395 km
Underground network	22 km	296 km	321 km	639 km

3.4.2. Queenstown load

Frankton's network load is similar to Cromwell's but with a larger airport and without the irrigation loads. The peak demand for all zone substations in this sub-network is during winter.

3.4.3. Key consumers

Our key consumers for the Queenstown sub-network are summarised in Table 3-12.

Table 3-12: Queenstown sub-network consumers

Consumer	Description
QLDC and CODC local councils	The total load of the Central Otago District Council (CODC) and Queenstown Lakes District Council (QLDC) sites is significant. As in Dunedin, the most important loads are those associated with water and wastewater pumping and treatment. Most of the CODC and QLDC sites have alternative HV feeds that are manually switched as required. These sites are a priority for restoration of supply for any natural disaster, most likely in co-operation with Civil Defence Emergency Management. A growing population would require expanding or new utilities (WWTP and WTP) which would have new electricity connections and supply requirements.
Tourism	Queenstown is a tourist destination. Peak tourist days are in the winter period, in particular the July school holidays, when domestic and international tourists flock to the area. Airports, ski fields, accommodation, township centres, and activity areas are typically very busy during this period. Tourists also congregate in the area in summer. Increasing visitors will spur development of accommodation and hence increased electricity demand.
Queenstown Airport	In conjunction with tourism to the region, the Queenstown Airport has grown from a small regional airfield to a busy airport. As in the case of Dunedin's airport, there are commercial and air traffic safety implications in the event of loss of supply. The airport operates a standby generator for critical loads and peak demand management. A feeder from Frankton substation supplies the airport. The network is meshed, and a number of alternative supply options exist, including supply from Commonage substation in the unlikely event the Frankton substation is out of service. Electrification of planes will require large amounts of electricity and presents uncertainty to network investment, as these are large loads that will require new assets to be built with unknown demand and development schedules. A large fleet of rental cars is stationed near the airport. As these transition to EVs, growth in charging load is expected.

Consumer	Description
Coronet Peak and Remarkables Ski Fields	Load at these sites includes ski lifts and snow-making machinery, as well as supply to related buildings. Ski-lift load is relatively consistent on days that the fields are open. Snow-making load occurs mainly on cold mornings early in the winter season but can run all day if natural snow is lacking and conditions are suitable for snowmaking. Peak loads generally occur during the July school holiday period when snowmaking overlaps with lift operations. All ski fields receive supply via single feeders over difficult terrain, with only limited backup. Ski fields are typically open for around 80 days per year, depending on snow conditions. Loss of electricity supply during a busy day – such as during school holidays – would cause significant financial loss. Load outside the ski season is generally very low.
Irrigation	Cromwell and Clyde have a significant amount of irrigation load. Irrigation demand is relatively consistent over the summer period but may be delayed by an unusually wet spring. At the end of the season irrigation load may reduce if it becomes too dry and sources of race water become limited. Irrigation demand differs in each location. In some areas water is pumped over relatively long distances and/or to relatively significant heights, resulting in high electrical load per irrigated land area. Other areas have lower demand as the pumping is from nearby surface ponds and races.

CHAPTER 4

CONSUMERS & STAKEHOLDERS

We put our stakeholders and consumers at the centre of our decision-making to ensure we meet their needs, listen and respond to their concerns, and provide the level of service they expect.

4.1. OUR STAKEHOLDERS AND THEIR INTERESTS

Proactive and effective stakeholder engagement remains a high priority for Aurora Energy and helps inform our decision-making. Table 4-1 outlines our key stakeholders, what their interests are, and how they are identified.

Table 4-1: Stakeholders and their interests

Stakeholder group	Description	Key interests	How interests are identified
Electricity consumers	All consumers connected to the Aurora Energy network	Reliable and safe power supply Accurate and timely information on unplanned and planned outages Affordability High standard of customer service and responsiveness A network that enables future DER choices	Customer satisfaction surveys Direct interaction/liaison Feedback via complaints, customer experience team
New connection consumers and their agents	All parties involved in getting connected to the Aurora Energy network	Simple process for connection services or alterations to existing connections – affordable and on time, with clear and timely communications Ability to connect solar or other generation	Direct communication with consumers, electricians, and approved contractors
Landowners and communities hosting our assets	Anyone who has Aurora Energy-owned assets on their property	Safety Easement conditions Appropriate access arrangements Clear communication	Direct communication Periodic consultation
Transpower	Nationwide transmission company and system operator, owns the GXPs on Aurora Energy's network	Supply and demand coordination Investment for growth Commercial relationships	Direct communication Systems and protocols to facilitate immediate communication for operational issues
Electricity retailers and distributed generators	Retailers: Buy/sell electricity; hold the relationship with consumers Distributed generators: electricity generation from local sources that is connected to the Aurora Energy network (not Transpower's national grid)	Lines charges/time of use pricing Reliability of supply Contractual arrangements How we manage consumer complaints Ease of doing business with us Future planning and DER	Use of System agreements Relationship meetings Feedback on AMPs
Regulators	Commerce Commission Electricity Authority WorkSafe	Long-term interests of consumers Economic efficiency Compliance with statutory requirements Accurate and timely information Decarbonisation	Submissions Relationship meetings Workshops and conferences
Media	Print, online and radio channels used to broadcast to the public	News	Direct communication
Property developers	Acquire and enhance land and properties	New connection policies and costs Switching off power during relocations	Direct communication

Stakeholder group	Description	Key interests	How interests are identified
Government agencies City, district and regional councils	Waka Kotahi the New Zealand Transport Agency Dunedin City Council Central Otago District Council Queenstown Lakes District Council Dunedin City Council Otago Regional Council	Public safety Environmental protection Support for economic growth Control of assets in road reserves	Direct communication Submissions RMA applications
Contractors and service providers	Aurora Energy has contractual arrangements with approved contractors and service providers to perform asset replacement and network growth projects, alongside regular maintenance of existing network assets	Safe working environment Maintenance and design standards Maintaining good contractual relationships Clear forward view of work	Contractual requirements Discussions with field staff Quality documentation feedback
Shareholders and the Board	DCHL Board members	Prudent risk management Compliance Strong governance	Board meetings Shareholder briefings Reporting

Aurora Energy staff are also a key stakeholder group. Developing existing talent and supporting continuous learning, prioritising staff wellbeing, and offering flexibility and an inclusive working environment to cater to a diverse workforce with different needs are important to our team members. Regular pulse surveys give us valuable feedback on areas where we can improve, and we are proud to have a sustained satisfaction score above 85%. Implementing an internal communications strategy in the near future will help us build on existing staff engagement, to be an employer of choice.

4.2. ENGAGING WITH CONSUMERS

Consumers are at the heart of our business, and we continue to build a customer-focused organisation where people are at the centre of day-to-day decision-making and planning. Enabling the energy future of our communities is our purpose; and supporting New Zealand's transition to electrification is one of our critical drivers.

Aurora Energy is investing in the network to ensure we can deliver the services consumers value. Decarbonisation, resilience and population growth are the key long-term drivers of investment in our network. The work we're doing now will ensure our electricity supply capacity will keep pace with consumers' growing electricity demand and evolving needs.

In essence, consumers want an affordable and reliable electricity supply and up-to-date information about power outages. As a result of our spending programme, some consumers are experiencing a higher-than-usual number of planned outages. We work proactively with these communities to provide information and support while this necessary work is undertaken.

Aurora Energy has a comprehensive communications and engagement strategy that outlines how we promote the organisation, the work we are doing in each sub-network and how this will benefit consumers, and how we will facilitate two-way conversations so we can continue to listen and respond to their needs.

The majority of consumers on the Aurora Energy network are residential and small commercial (approximately 99%).

Our large/major consumers are from the healthcare, farming, food processing, transport, manufacturing, tourism, council, and university sectors. Chapter 3 provides further detail on our larger consumers.

Aurora Energy is committed to open and transparent engagement on our activities with our diverse consumer base.

We are there for consumers 24/7 and keep the lights on more than 99% of the time.

4.2.1. Customer charter

Aurora Energy launched a new Customer Charter in August 2024. Replacing our original charter that was developed in 2017, it better reflects what customers have said is important to them. It follows an extensive review, and public consultation in November 2023.

The Customer Charter outlines our service commitments to consumers, what we need from them to provide a safe and reliable electricity supply, and how we will compensate them if we fail to meet certain customer service incentives.

We will report to the public annually on how we measure up against the service levels.

USING DATA TO UNDERSTAND CONSUMER NEEDS

In the lead-up to our CPP application, we carried out comprehensive engagement with consumers on what they valued and expected from Aurora Energy as their lines company. Annual surveys during the CPP period provide ratings on key measures to inform how Aurora Energy can engage better with consumers, improve customer experience, and build trust and confidence in the CPP planned expenditure. We conducted a benchmark survey in 2022, followed by a panel survey in 2023, marking the start of longitudinal tracking to gauge year-on-year progress.

The 2024 survey included a full survey and a continuation of the panel survey. Results were positive, with statistically significant increases in awareness and perceived performance for consumers, and an increase in trust levels.

ENGAGING DIRECTLY WITH CONSUMERS

Two-way conversations with consumers on the Aurora Energy network allow us to gain valuable feedback and build stronger relationships. We attend a number of gala days and A&P shows around Otago over the summer months to engage with consumers, educate them about who we are and what we do, and answer their queries. We also engage with local business communities by hosting events through Business South and Chambers of Commerce.

Aurora Energy's community relations programme ensures we have proactive and direct communication with consumers who are impacted by the work we are doing to upgrade and maintain the electricity network in their area. We contact consumers who will experience multiple planned outages to provide information about the work and how it will benefit them, to give context to the outage notifications they receive from their retailers.

We also have a project to identify and monitor areas on the network where consumers experience reliability of supply that is lower than what we would expect. We are in direct contact with consumers in these 'reliability hotspots' to let them know we have a spotlight on their area and tell them about work we have done or are planning to improve their electricity supply. This project has been reviewed to ensure it can be integrated into 'business as usual' processes.

WHAT CONSUMERS HAVE TOLD US

Results from the 2022 and 2023 surveys have informed Aurora Energy's Customer and Engagement Strategy, our new Customer Charter, and the Customer Outage Guidelines that we use to minimise consumer impact when planning work. Subsequent survey results have helped refine Aurora Energy's communications and engagement approach, to ensure we continue to meet consumers' needs.

Figure 4-1 shows key findings from our full 2024 customer satisfaction survey, as prepared by the research provider. Panel survey results support these findings.

We are working with the research provider that conducts the surveys to see what additional actions we can take to build on the positive results.

Figure 4-1: 2024 Customer satisfaction survey outcomes

4.3. HOW CONSUMER NEEDS INFORM OUR PROGRAMME

We remain committed to providing a high standard of customer service for all Aurora Energy consumers. Listening to feedback ensures we provide information that is relevant, while the annual customer satisfaction surveys mentioned in the previous section provide valuable feedback and help us monitor effectiveness.

Increasing the community's knowledge about Aurora Energy, building trust, and listening to and meeting the needs of consumers will help us achieve Aurora Energy's purpose to enable the energy future of our communities.

We accommodate stakeholder interests into our asset management practices in several areas, as outlined in Table 4-2.

Table 4-2: How we accommodate stakeholder interests in our asset management activities

Stakeholder Group	Asset Management Activities
Communities	• Provision of meaningful, timely, and accurate information • Development of safety plans to address standard design principles and replacement of end-of-life assets • Planning to ensure the network meets changing needs for how electricity is being used • Investment in resilience planning to address the potential impacts of major weather events on electricity supply
Electricity Consumers	• Network growth and development plans • Security of supply guidelines to reflect customer performance needs and expectations • Optimising asset lifecycle capital and operational expenditure
Regulatory and Legal	• Compliance with regulatory and legal frameworks • Public disclosure of information based on reporting requirements

In cases of competing interests between stakeholder groups, we will endeavour to provide a suitable resolution. Ultimately, our Board determines the means to remove any significant conflict between stakeholder interests. In some cases, Utility Disputes is an appropriate entity to facilitate conflict resolution.

Summarised below are examples of how we engage with consumers and ensure we have avenues to hear their views so we can make more effective decisions when planning work.

- Multi-channel approach to provide regular updates on Aurora Energy's works programme using the channels consumers prefer. This includes integrating reporting requirements for our CPP into our 'business as usual' communications to show we are committed to delivering on our promise to upgrade the network.
- Public safety campaigns/communications. We launched a new campaign in 2024 that targets safety messages more effectively and aligns with the Aurora Energy brand and narrative. An updated contractor safety campaign is in development.
- Attendance at public events such as A&P shows and hosting events with the business community provides opportunities for face-to-face interaction and feedback.
- Providing information about future energy needs, including how to connect solar to the network.
- Implementation of a new outage management system alongside a new website has improved the accuracy and timeliness of outage information, as well as how it is displayed.
- Implementing a brand narrative to help consumers better understand who Aurora Energy is and what we do.
- Our community relations programme ensures we are working directly and proactively with communities impacted by multiple power outages.
- Reliability hotspots – communicating proactively with communities in areas of the network that experience reliability that is lower than our expectations, so they are aware of the work we are doing to improve service levels.
- Improvements to customer-initiated work processes.
- A robust complaints process that includes target timeframes for response and resolution ensures all complaints are captured, resolved, and reported on. We clearly communicate across a range of channels that consumers can seek advice from Utilities Disputes if they are unhappy with the response they receive from Aurora Energy. Complaints are reviewed to identity potential themes that suggest improvements to systems, processes, or customer service.

4.3.1. Dunedin sub-network

With over 58,000 ICPs, our Dunedin sub-network is Aurora Energy's most densely populated network area. It has a resilient network configuration that has more switching options than other areas of the network. This means shorter unplanned outages due to a predominantly easy-to-access network. Like much of the region, network resilience is important to consumers, particularly ensuring our assets can withstand more frequent weather events.

4.3.2. Central Otago & Wānaka sub-network

This is a high-growth area in terms of network development. At the same time, this part of the network also includes some of our most remote and rural areas, with some long spans of line and proportionately few connections. Consumers want assurance the network will be able to support decarbonisation and growth as well as provide a reliable electricity supply. There are just over 24,000 ICPs in this area.

4.3.3. Queenstown sub-network

Queenstown remains an epicentre of tourism and business activity, with strong growth trends and high expectations regarding resilience and capacity. Access to parts of this network can also be challenging due to the rugged terrain and environmental significance. Consumers want to be reassured that Aurora Energy is working alongside Transpower and the local council to plan for energy resilience. The Queenstown Lakes network has just over 15,000 ICPs but a peak tourist population approaching 100,000 people.

4.4. CONNECTING CONSUMERS

Aurora Energy's website has a 'Get Connected' page that provides information for consumers who want a new connection to our network or an alteration to an existing connection (including relocation of an existing asset).

Aurora Energy certifies and authorises 'approved contractors' to carry out work on the Aurora Energy Network. This process has created a market of approved contractors that allows consumers to choose an approved contractor to design and build a solution that best suits their requirements and budget. The approved contractor manages the connection process, timelines, and any planning delays on behalf of the consumers.

We have an online portal where our approved contractors can submit applications for solar, EV and new connections, along with alterations to existing supplies. This portal communicates updates on the status of the applications and the agreed capital contribution (if any) from Aurora Energy.

This is underpinned by clear standards and practices for connecting new consumers, whether it's an EV connection, a house, a large industrial building or a subdivision, or to connect consumers' solar power or other form of generation.

Our standards are:

- Network Connection Standard (AE-CC01-S)
  This standard defines the technical and commercial requirements for connections to the network
- Large-scale Distributed Generation (LSDG) Connection Standard (AE-NR04-S)
  This standard covers Aurora Energy's requirements for the connection of LSDG with a maximum export capacity greater than 10 kW, including inverters connected to energy sources or energy storage systems, which can connect to and operate in parallel with the Aurora Energy distribution network.

  Small-scale Distributed Generation (SSDG) Connection Standard (AE-NR03-S)
  This document defines Aurora Energy's requirements for the connection of small-scale inverter-based distributed generation (SSGD) (capacity less than 10 kW) to the Aurora Energy distribution network.

Information about constraints is shared and discussed with connecting customers on request.

Further information about new connections or changes to connections can be found in Section 16.1.2.

CHAPTER 5
SERVICE LEVELS

We provide services to meet the needs of consumers. We use specific service levels and targets to track how we are doing against consumer expectations.

We know that a sustainable, secure, affordable and efficient energy supply is important to the environment, consumers, and the wider community. That's why we are committed to working with our communities in new ways to support the energy choices they make and managing our business so we can contribute to a sustainable energy future. For Aurora Energy, this commitment is anchored in clear actions.

Service levels help us ensure we are meeting the long-term needs of consumers. By tracking our performance against measurable targets, we are able to demonstrate to key stakeholders that our approach to asset management is producing the intended results. Service levels also allow us to highlight our progress within areas where we are targeting improvement.

Our service levels cover our core business areas and are aligned to Aurora Energy's overall strategic focus areas, which helps us set a clear consumer focus for our asset management activities and objectives.

5.1. OUR TARGETS AND PERFORMANCE

We currently monitor service levels across three key business areas: safety, reliability, and customer service. For each service level, we have specific performance targets that we monitor over time.

5.1.1. Safety

CONTRACTOR SAFETY

Service Level: Ensuring staff and contractors return home safely from work each day.

Performance Target: Total recordable injury frequency rate (TRIFR) of 3.5 injuries per million hours worked.

Our key performance targets for health and safety are set out below. Recognising the need for continuous improvement, the key strategies and initiatives discussed here will help drive a stronger safety culture. Over time, this will improve our TRIFR toward a best practice performance level of 3.5 or better.

PUBLIC SAFETY

Service Level: Ensuring potential risks to the public are managed as low as reasonably practical.

Performance Target: We target zero serious injury events (excluding third party contacts with the network) involving members of the public.

We undertake a range of initiatives including asset inspections, public safety communication, and incident monitoring to ensure potential risks to the public are managed appropriately. Table 5-1 gives our Health & Safety performance, encompassing both actual harm to public and TRIFR.

Table 5-1: Health & Safety performance

Target area	RY25 Target	Performance			
		RY21	RY22	RY23	RY24
Actual harm to public	0	0	0	2	0
TRIFR	<3.5	5.4	5.1	4.2	3.9

SAFETY CRITICAL ASSETS

Service Level: Ensuring our assets perform in a safe manner.

Performance Target: Cast iron pothead cable terminations removed from service within RY26. Backlog of orange-tagged poles addressed by end of RY24.

Cast iron pothead (CIPH) terminations present a potential safety concern, and we have set a target to remove all such terminations by the end of RY26. Table 5-2 sets out our CIPH removal progress to date.

Table 5-2: CIPH removal

Target area	AMP 2020	AMP 2022	AMP 2023	AMP 2024	AMP 2025
Remaining CIPH	400	250	165	100	65

We have 65 cast iron potheads remaining on the network and are on track for our RY26 target. For further discussion, see Section 11.5.

In our 2018 AMP, we identified the need to reduce our backlog of red-tagged poles, which stood at more than 1,000 at the time. By December 2022 we had cleared the backlog to steady-state levels.

For orange-tagged poles, our backlog as of October 2023 stood at 472. Our target in RY24 was to reduce the backlog; and as of October 2024, we had reduced this total to 170 poles, with only 62 of them classified as backlog. The others were discovered within the last 12 months. See Section 11.3.1 for our renewal priorities for our poles fleet.

5.1.2. Reliability

Service Level: Ensuring a reliable power supply to consumers.

Performance Target: Annual system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) performance is within the set regulatory limits.

Reliability of supply is measured in terms of frequency and duration of interruptions per customer. Major factors in determining reliability performance include asset health, field response times, and security of supply in terms of our ability to back up or restore lost supply. The service our consumers receive from the network is partly determined by the condition of assets in their region. External factors also contribute to reliability, such as weather conditions, vegetation, possums and other wildlife, and third-party incidents such as vehicle impacts.

Network reliability reflects an historical trade-off between cost and service, and improved reliability performance often requires significant expenditure. Achieving target levels of service performance requires identification and mitigation of multiple risks that can cause asset failure.

Using our advanced distribution management system (ADMS), we record all planned and unplanned outages that occur on our network, along with key information relating to the type of event, the number of customers affected, and the total time without supply for all customers involved. This information is then recorded in our outage database to enable our regulatory teams to calculate SAIDI and SAIFI using the ruleset outlined by the Commerce Commission.

More information on reliability targets is provided in Appendix E.

Table 5-3: Historical performance (unplanned reliability)

Target area	Historical Performance				
	RY20	RY21	RY22	RY23	RY24
SAIDI Unplanned Target	103.00	146.29	124.94	124.94	124.94
SAIDI Unplanned Actuals	109.90	85.39	98.45	106.45	95.48
SAIFI Unplanned Target	1.90	2.51	2.07	2.07	2.07
SAIFI Unplanned Actuals	1.59	1.46	1.50	1.75	1.31

UNPLANNED PERFORMANCE

Minimising the number of unplanned outages on our network is a key service performance indicator for consumers. As part of our CPP application, we revised our performance targets to align with the regulatory limits set for us by the Commerce Commission. To date, we have complied with the CPP limits.

In November 2024, the Commerce Commission set revised limits for when Aurora Energy ends its CPP period and resumes a DPP (default price-quality path). The DPP4 limits have been set at a higher rate for SAIDI and a lower rate for SAIFI. As shown in our unplanned reliability forecasting (Figure 5-1 and Figure 5-2), we expect to remain compliant with all limits set, up to RY30. For unplanned SAIDI, we expect to trend toward the target value over time.

Our reliability forecasting methodology is based on recent performance (RY20–24) to set our expectations for the beginning of the planned period. We believe we have curbed our worsening reliability trend in recent years, and so the RY20–24 period represents our steady-state performance. We do expect, however, to see some variability in performance year to year.

We then expect to see an improving trend in performance over ten years as a result of several ongoing reliability improvement initiatives:

- Security of supply improvements for our subtransmission network (see Section 10.1.2).
- Root cause analysis on asset failures which helps to monitor and address asset performance issues (see Section 11.2.5).
- Reliability Hotspots programme, which has been revised to provide ongoing monitoring of feeder performance to ensure recurring issues are resolved promptly (see Appendix E).
- In recent years, we have seen an increase in the number of fallen trees and branches damaging lines and causing faults. With proposed changes to the Tree Regulations, we may have greater powers to remove trees that present a high risk to network reliability (see Section 11.2.4).

Through the CPP period, we have targeted our network investment toward improving the safety of our asset fleets. Based on our improved approach towards asset inspection, maintenance and renewals, we expect to see a general reduction in the number of asset faults over time.

Beyond the CPP period, we have targeted investments towards network upgrades to reduce the impact of faults on consumers. These upgrades will help to address reliability issues in areas that sit below our expected performance targets. Unplanned performance expectations for each sub-network are provided in Appendix E.

Starting in 2024, Aurora Energy has also established a Customer and Reliability Leadership Group with representation from several business units. Meeting monthly, the group monitors network reliability from several perspectives to provide early identification of emerging performance issues.

Figure 5-1: SAIDI – Unplanned Performance

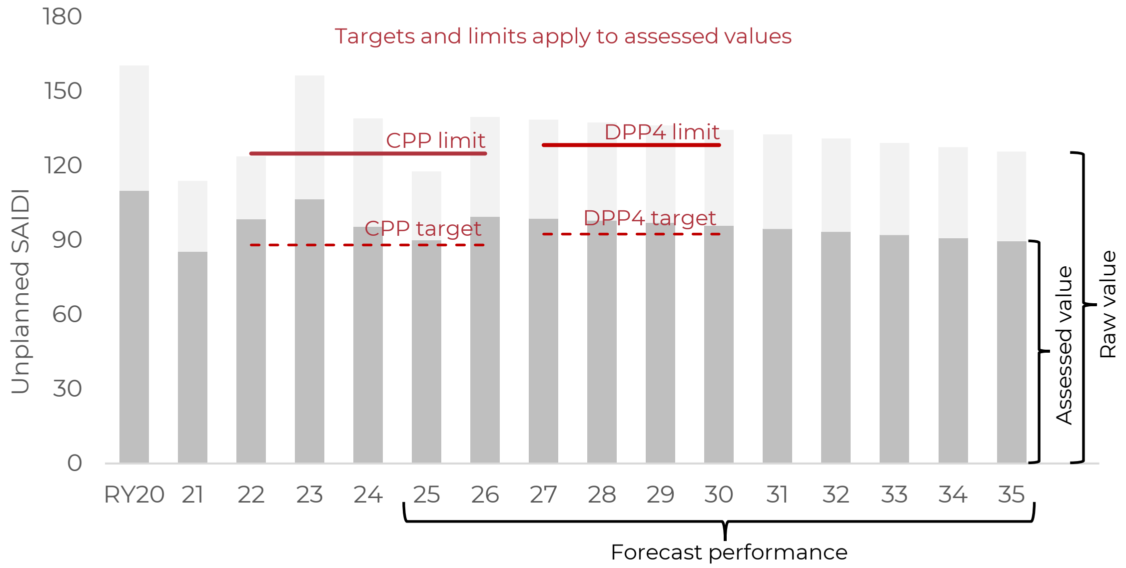


Figure 5-2: SAIFI – Unplanned Performance

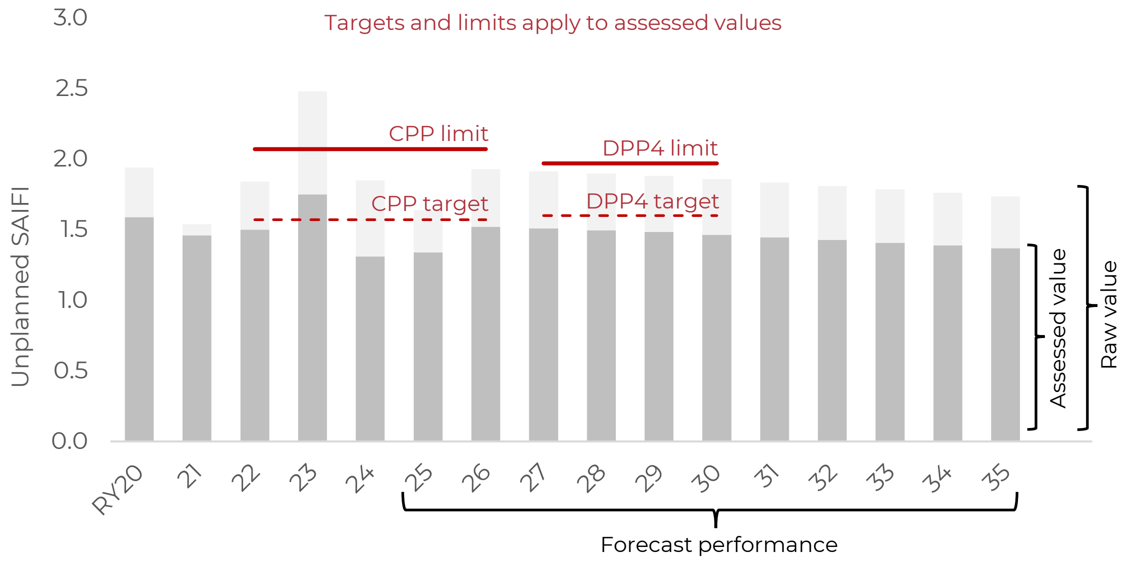


Table 5-4: Terminology used in reliability forecast charts

Term	What it means
CPP Targets and Limits	Values set for Aurora Energy during the current customised price-quality path period (CPP), which applies for RY22–26.
DPP4 Targets and Limits	Values set for the fourth default price-quality path period (DPP4), which applies to Aurora Energy from RY27–30.
RY	Regulatory Year, starting from April 1.
RY20–24 Period	Historical performance from previous years.
RY25–35 Period	Forecast performance for current year (RY25) and the ten-year planning period.
Assessed Value	Some adjustments are made to 'raw' SAIDI and SAIFI numbers before assessing performance against regulatory targets and limits. For unplanned outages, major event days (MEDs) such as severe wind and weather events are excluded from the assessed value. For planned outages, a discount is applied where customers are correctly notified according to set rules. The reliability forecast charts in this section include a darker shaded portion for each year to indicate the assessed value, and a lighter shaded portion to indicate the amount of discount applied to the raw SAIDI and SAIFI values. *Note: no discounts are applied to planned SAIFI.*
Unplanned	Customer-impacted outage where customers are not given prior notification. This generally includes faults, but may also include outages carried out at short notice.
Planned	Outages carried out for scheduled work where the customer is given prior notification.

PLANNED PERFORMANCE

While we understand the need to keep the power on as much as possible, sometimes we need to plan outages so that our crews can work safely on our network. In recent years, the impact of planned outages has been greater on consumers as we have committed additional expenditure into improving the health of our network. To minimise the impact of planned works on our consumers, we aim to bundle multiple jobs into a single outage to avoid any return visits. Where possible, we also try to avoid planned outages when electricity supply is most needed, such as during school holidays or during the coldest winter periods.

Beginning in RY17, we have increased the number of planned outages to address historical issues with the condition of our network. While the levels of planned SAIDI and SAIFI have increased over this period, we remain well below the limits set for us during our CPP period. In November 2024, the Commerce Commission published Aurora Energy's reliability targets for when we transition to a default price-quality path in RY27 (DPP4). We anticipate that our planned reliability performance will sit within the new target values.

Our forecast for planned reliability over the planning period utilises information from our planned expenditure to estimate the potential impact of all programmed works during the year.

In our forecasting approach, we aim to form the best estimate of the impact of our upcoming planned works on reliability. Several factors may affect the accuracy of the forecast shown in Figure 5-3, including outages affecting greater or fewer customers than expected, reprioritisation of our planned work programmes, or additional planned outages becoming necessary due to unforeseen circumstances.

In recent years we have undergone a period of intensive expenditure on our network to improve asset condition. Over the planning period, we expect that this need will reduce. Our forecasting reflects the change in customer impact from planned outages.

Table 5-5: Historical performance (planned reliability)

Target area	Historical Performance				
	RY20	RY21	RY22	RY23	RY24
SAIDI Planned Target	116.00	195.96	195.96	195.96	195.96
SAIDI Planned Actuals	110.71	102.73	124.50	110.34	121.83
SAIFI Planned Target	0.51	1.11	1.11	1.11	1.11
SAIFI Planned Actuals	0.61	0.68	0.83	0.60	0.76

Figure 5-3: SAIDI – Planned Performance

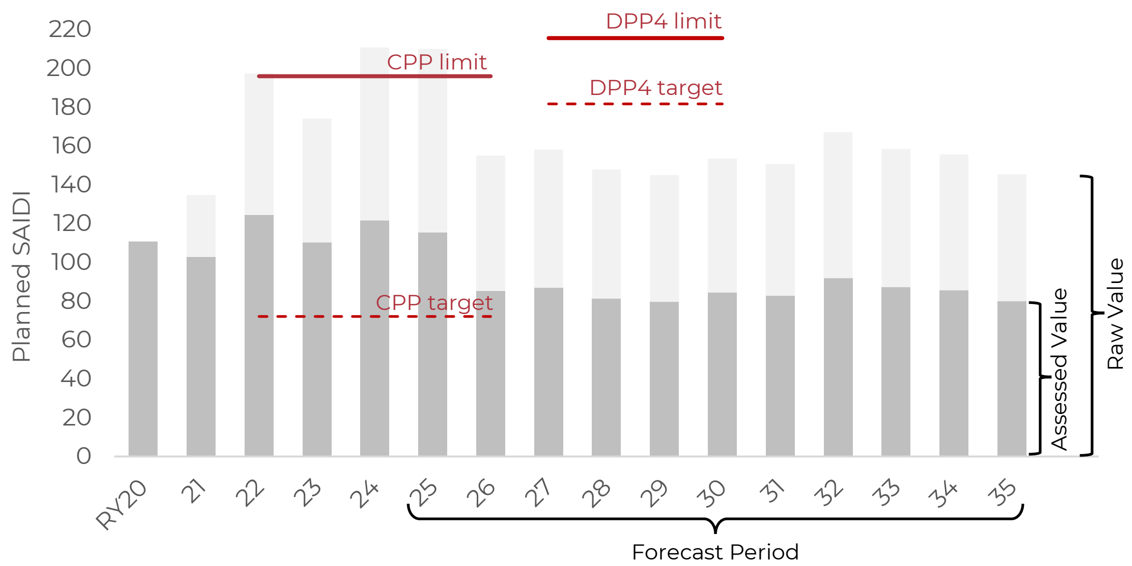
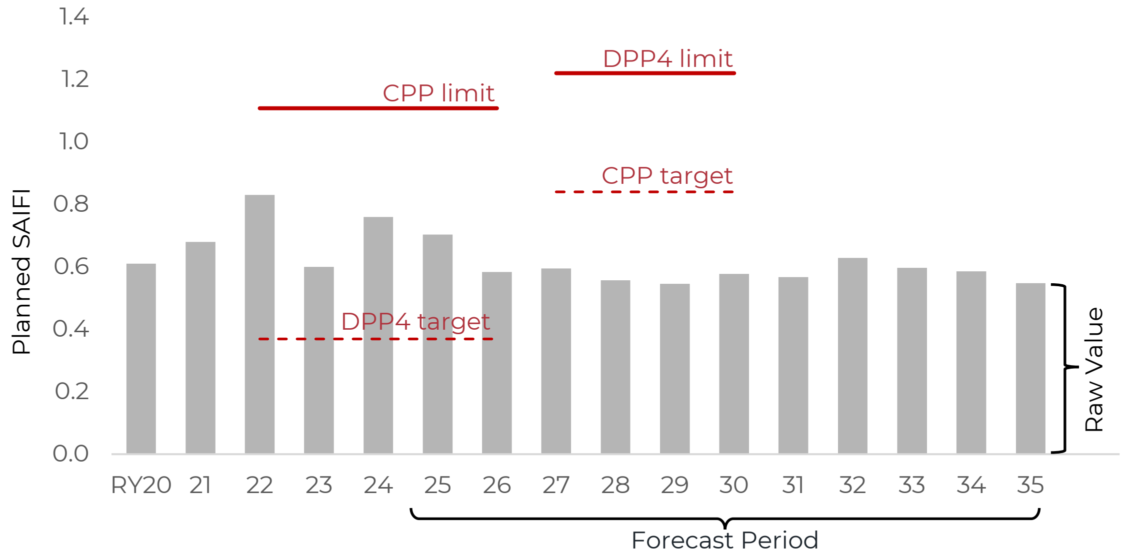


Figure 5-4: SAIFI – Planned Performance



5.1.3. Customer service

Service Level: Ensuring we proactively respond to issues raised by consumers.

Performance Target: Set timeframes for responding to and resolving all power quality complaints.

POWER QUALITY ENQUIRIES/COMPLAINTS

As part of our ongoing CPP Development Plan, we are focused on improving our visibility and management of network power quality issues. Our goal is to identify and address emerging power quality issues before they impact consumers.

In the initial phase of our plan, we identified the need for a streamlined process for responding to power quality enquiries and complaints. We have set ourselves stage gate targets to respond, perform our analysis, and resolve any identified issues, and have been collecting performance data since 2020 (see Table 5-6). We have seen significant progress in all three target areas since we began our performance tracking.

Our average response time is generally less than two business days, with only four cases in total exceeding the seven-day target (zero in 2022, 2023, and 2024).

For 2024, we are well on track to achieve our target of 40 business days for average resolution times, with an average resolution time of 27 days and just five cases still in progress as at the end of January 2025.

CUSTOMER SATISFACTION SURVEYS

Survey results inform how we can improve consumer engagement and customer experience, and how we can build trust and confidence in Aurora Energy and the work we are doing to upgrade and maintain the network. For more information, refer to Section 4.2.

CUSTOMER CHARTER

In 2024, Aurora Energy launched a new Customer Charter, which outlines service commitments, what consumers can expect from us, and how we will compensate them if we fail to meet certain customer service incentives. For more information, refer to Section 4.2.

Table 5-6: Timeframes for responding to power quality enquiries/complaints (as at end January 2025)

Calendar Year	Total Power Quality Enquiries/Complaints	Average Response Time	Average Analysis Time	Average Resolution Time
Target	N/A	7 business days	20 business days	40 business days
2020	31	3.65	39	68
2021	29	10.17	42.1	61
2022	46	1.54	37.87	53
2023	56	1.41	38.5	55
2024	46	1.59	12.98	28

5.2. FUTURE-FOCUSED SERVICE LEVEL TARGETS

Our traditional target service levels encompass safety, reliability, and customer service. As we mature in our approach to asset management, we are keen to refine our approach to service levels to best capture our path to improvement against our core business. In developing new service levels, we must ensure our targets are:

Meaningful: We need to identify performance targets that relate to our asset management activities and best reflect the needs of key stakeholders. We also need to be mindful of how we set targets, to ensure they are realistic but challenging and to ensure the right balance across a range of consumer expectations (for example, reliability vs safety vs affordability).

Measurable: We need to ensure we have the right information to accurately monitor our performance against each target value without over-burdening our resources.

Actionable: We need to ensure we have processes in place to address performance issues when they are identified. This involves outlining appropriate improvement actions and ensuring relevant business units are assigned responsibility for each service level.

Our strategic drivers for success help to frame the priorities in our annual business plans. During 2025/26, we will continue to progress and elevate our traditional service levels to adapt to the dynamic landscape we operate in. By focusing our future performance targets on our key strategic areas, we can ensure that our internal asset management goals align with stakeholder expectations.

Table 5-7: Service levels aligned to our strategic focus areas

Service Level Focus Areas	Improvement Pathway
Our People – Supporting the development of our people and creating a culture that attracts the best talent	
Competency – Ensuring our staff have the necessary skills to support our maturing approach to asset management.	Our Competency & Training Development Plan is underway, with key milestones outlined in Section 6.7. By RY26, we aim to improve our assessment score in this area against the Asset Management Maturity Assessment Framework (AMMAT).
Future Network – Investing in our network and operations to meet the changing electricity demands of customers	
Unplanned Reliability – Our reliability performance is currently assessed at a network level. In future, we aim to set performance targets at a local level, with a future aim to have targets for every consumer on our network.	A recent update to our outage management system (OMS) gives us greater ability to monitor outage histories for individual consumers. With further analysis, this data will help to form target levels across different areas of the network.
Unplanned Reliability – We aim to respond quickly to unplanned power outages. As part of our current Customer Charter, we set timeframes for restoring power following a power cut.	We have developed a Network Fault Response Standard (AE-OO01-S), which includes internal targets for fault response and restoration times across different areas of the network. These targets took effect from 1 April 2024 as part of our updated Field Services Agreement with our fault services crews.
Customer & Community – Focusing on what matters to customers and partnering with local business and stakeholders to support regional growth	
Customer Satisfaction – Ensuring we identify what matters to consumers and aligning our service offerings to their expectations.	We conduct regular customer satisfaction surveys (see Engaging with) and have established target metrics across a range of customer focus areas that we will report on annually as part of our new Customer Charter.
Planned Reliability – We have undertaken significant work to improve our processes for notifying consumers around planned outages and keeping them up to date on delays and cancellations.	We currently undertake internal tracking of non-notified outages and outage deviations as part of our continual improvement process. Once we establish steady-state performance targets, we will make them available within our asset management plan.
New Connections – Consumers require clear communication from us around expected timeframes and potential delays for different types of new connections.	We have streamlined our processes around applications for new connections (see Section 4.4). Given that each connection is different and installation requires involvement from external parties, we continue to explore a suitable approach for measuring our performance in this area.
Digital Enablement – Applying technology, innovation and new skills to drive digital transformation and productivity across the organisation	
Digital Enablement – Delivering value to consumers through improved productivity and enhanced decision-making tools	We have a clear pathway set out for the collection and use of asset data (see Section 6.4). See also our digital transformation pathway in Section 12.1.
Delivering Value – Demonstrably optimising future value for both customers and our shareholder	
Efficient Delivery – Focus on delivering business improvements to ensure long-term cost efficiencies.	As part of our cost estimation practices development plan (see our 2022 Development Plan), we have revised standard unit rates for volumetric work and for major project costs. This information will help us ensure our actual costs track well against forecast expenditure.

B

OUR INVESTMENT DECISION-MAKING APPROACH

CHAPTER 6

OUR ASSET MANAGEMENT APPROACH

We use our asset management framework to ensure we have 'line-of-sight' between stakeholder needs and our planned expenditure. We maximise the benefit and value that our assets provide by translating our corporate vision and strategic priorities into asset management objectives that guide all spending and operational decisions.

6.1. ASSET MANAGEMENT FRAMEWORK

Our asset management framework encapsulates all the key elements of an asset management system required to achieve alignment with ISO 55001.

The scope of our asset management framework includes:

- All electricity distribution network assets
- All supporting assets such as protection and monitoring equipment
- Non-network equipment including offices, computers and software solutions

The framework also considers human resources such as internal staff that directly or indirectly support our asset management activities, as well as others to whom we outsource asset-related activities, including service providers and contractors. Ultimately, our asset management framework encompasses all elements of our business that contribute to asset performance, whether directly or indirectly.

Our asset management framework illustrated in Figure 6-1 shows how our asset management strategy informs all stages of the asset lifecycle. The plan-do-check-act process is central to driving continuous improvement. We use this to monitor and control the effectiveness of our asset management activities.

As our asset management framework matures, we will continually review and update key processes and documents to reflect improvements. We review our planned expenditure annually to take account of improvements in our decision-making processes.

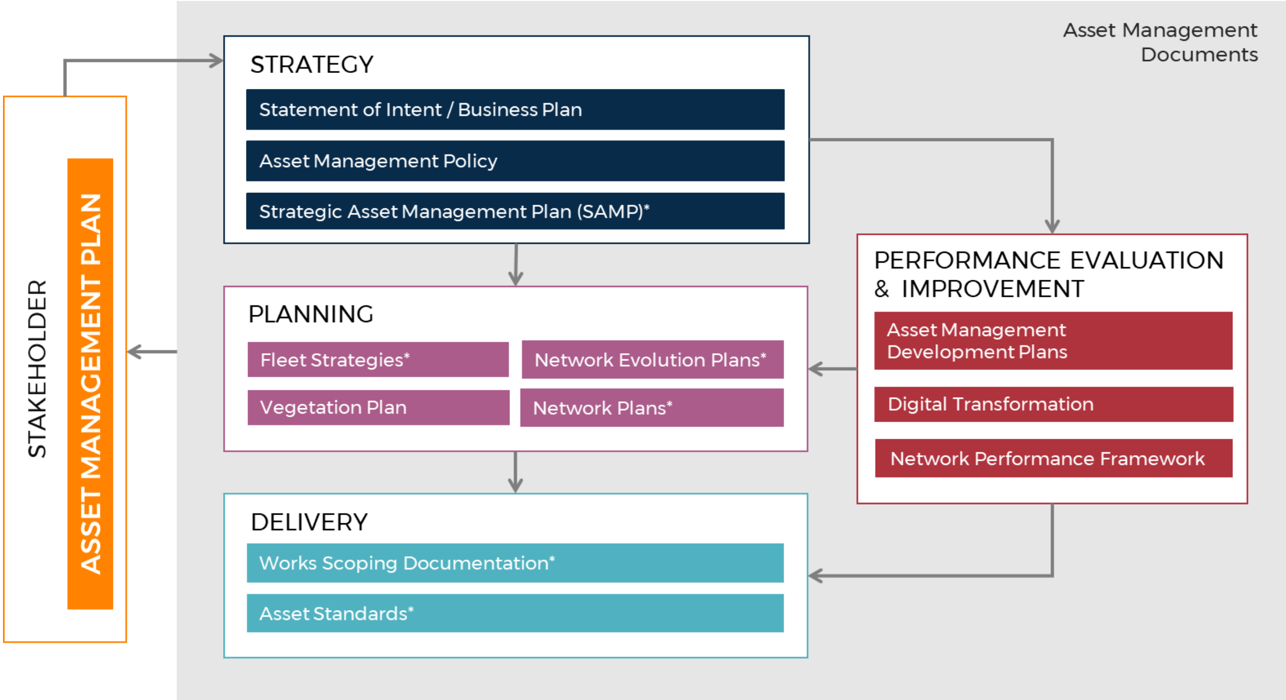
We have not conducted a formal audit of our asset management system since late 2019. However, this does not mean we have not continued working on further improvement. In our Asset Management Improvement Plan as part of our CPP Annual Delivery Report (ADR), we outlined several initiatives to improve our practices. We are currently developing our strategic asset management plan (SAMP), which contains a newly documented asset management framework. We have engaged leading industry specialists to ensure we are targeting the best industry practices in full alignment with ISO 55001.

Figure 6-1: Asset Management Framework

6.1.1. Our asset management documents

Within our asset management framework, we have a core set of asset management documents as outlined in Figure 6-2 and listed in Table 6-1. These documents provide a clear line of sight from our overarching business needs and objectives to our everyday actions.

Figure 6-2: Asset management document hierarchy



* Indicates documents in review or development.

Table 6-1: Aurora Energy's main asset management framework documents

Level	Document	Description	Status
Stakeholder	Asset Management Plan (AMP)	Describes our planned expenditure over a period of 10 years and the supporting information that guides our decision-making. Aside from its regulatory purpose, the AMP provides the opportunity to explain to key stakeholders how our asset management objectives and planned expenditure over the AMP period align with their needs. Stakeholder feedback informs our strategy and business planning.	This document – published 1 April 2025; updated annually
Strategy	Statement of Intent (SOI)	Sets out our high-level strategic/corporate objectives, intentions, and performance targets over a period of three years.	Published July 2024; updated annually
	Business Plan	Sets out our business direction for 2021–25 and the key outcomes that we aim to deliver over this period. The plan also provides financial forecasts over the period.	Published 2021; currently under review
	Asset Management Policy	Aligns our asset management approach with our corporate objectives through a set of strategic priorities.	Established 2019; refined 2024
	Strategic Asset Management Plan (SAMP)	Explains the processes and decisions required to develop a programme of planned expenditure that best meets our asset management objectives while remaining within our financial and delivery capability. The SAMP will also outline initiatives to increase efficiency by driving improvements to our asset data and our capacity to deliver.	In development

Level	Document	Description	Status
Planning	Fleet Strategies	Reflect our asset lifecycle model and set out how these processes and activities are applied to individual asset fleets.	Complete for all safety-critical fleets; development ongoing; continual improvement planning underway
	Network evolution plans	Identify changes to the network enabled by new technology or required by changing consumer behaviour or expectations.	In development
	Network plans	Identify strategic plans for each network area to meet growing and new loads.	Ongoing
	Vegetation plan	Outlines the annual work programme for vegetation management. The vegetation plan lists all circuits that require inspection and maintenance on an annual basis.	New plan in development; will take effect in RY26
Delivery	Works scoping	An annual work plan is utilised to ensure that project and maintenance work can be scheduled and delivered efficiently and to plan.	Produced annually
	Asset design and installation standards	Used to manage and deliver our investments and operational and maintenance activities.	Standard designs in development
Continuous Improvement	Asset Management Development Plan (AMDP)	Addresses strategy and planning, reliability management, risk and review, and asset management decision-making.	Published March 2022
	Reliability Management Plan (RMP)	Outlines our long-term approach for defining and meeting reliability performance targets, both for planned and unplanned interruptions (see Appendix E).	In development
	Digital Transformation Roadmap	Describes the organisation's strategy to efficiently leverage the benefits of new digital technologies whilst managing their inherent risks.	Horizon 1: RY24–RY25 roadmap implemented

6.1.2. Asset management policy

Our asset management policy sets out high-level asset management principles that reflect our vision and values. It highlights our Board's expectations regarding how we manage our assets and make our decisions. The policy has been developed to ensure a continuous focus on delivering the services consumers want in a sustainable manner that balances risk and long-term costs.

The policy covers a broad range of asset management principles, including the following statements that are particularly relevant to managing our assets at the current time. We will:

- Use robust processes and improved asset data to make asset management and lifecycle decisions, balancing cost, risk, and performance
- Understand and meet the needs and values of consumers and stakeholders, including iwi and environmental agencies, to align our decisions to our understanding of their balanced needs and values
- Take all reasonably practicable steps to protect all people affected by our assets and asset management activities
- Develop 'least regrets' plans that balance meeting short-term needs with an agile response to changing preferences of consumers in an uncertain future
- Seek best practice asset management, including alignment with the international asset management system standard, ISO 55001
- Comply with all statutory and regulatory requirements

6.2. ASSET MANAGEMENT OBJECTIVES

Our asset management objectives set the direction for all network management decisions. Derived from our Asset Management Policy, they:

- Guide how our organisational objectives relate to our day-to-day activities
- Provide context for internal and external issues that may affect our ability to achieve intended asset management outcomes
- Clarify how our asset management objectives support achievement of our business plan objectives
- Ensure we have the right frameworks, skills, technical capability, systems, and processes to efficiently deliver our strategy and optimise asset investments
- Drive our continuous improvement programme

We also use our asset management objectives to inform our investment drivers, which are described further in Chapter 2. This ensures we can prioritise activities such as network development projects in alignment with Aurora Energy's vision.

To ensure consistent alignment across our asset management activities, we have defined five key areas that link our strategic focus areas to our asset management objectives.

The asset management objectives outlined below extend upon the service levels described in Chapter 5 and provide inward facing objectives that ensure we manage our assets in line with our organisational objectives.

Figure 6-3: Hierarchical integration of asset objectives

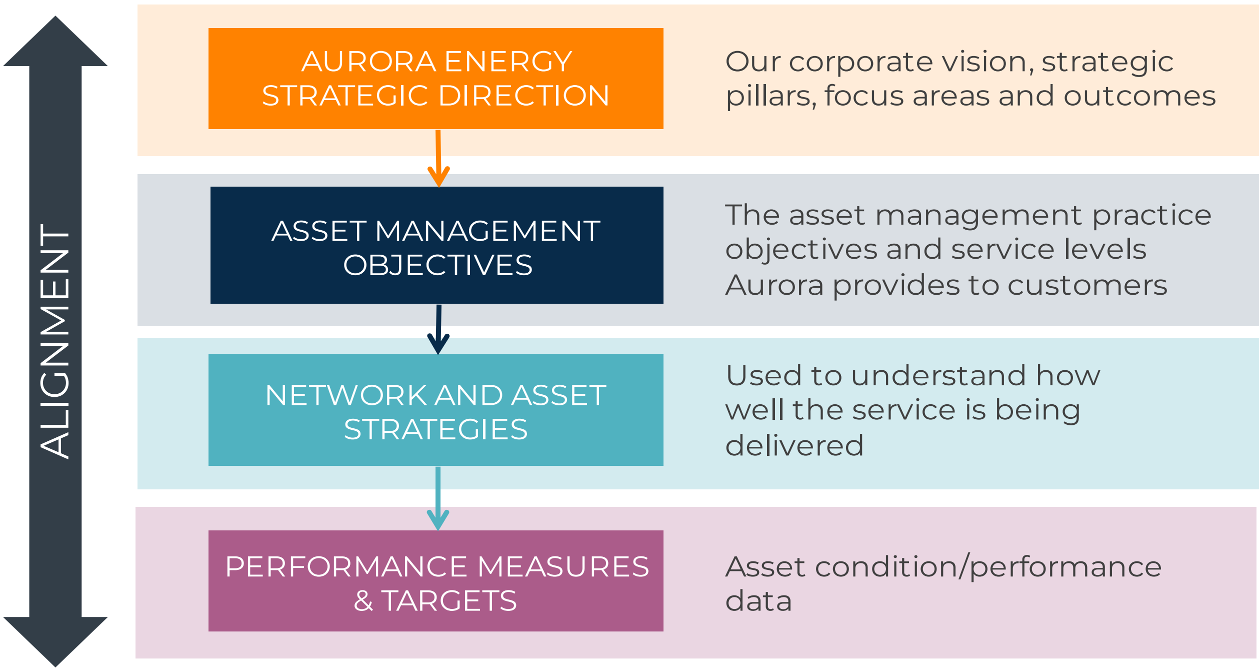
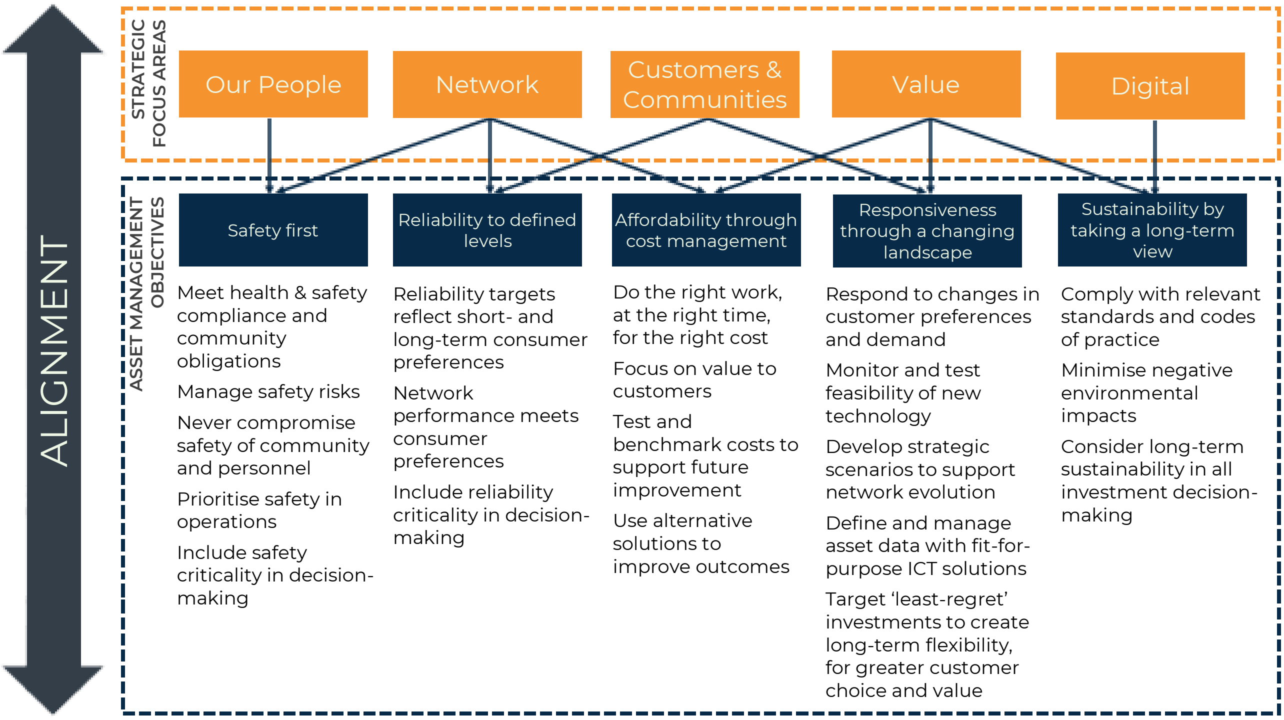


Figure 6-4: Strategic focus areas linked to management objectives



6.2.1. Safety

During the consultation process for our CPP application, consumers identified safety as their highest priority. As such, safety forms a key component for our asset management practices. Our network assets and some asset management activities pose potential safety hazards if not appropriately managed. Asset health and condition is linked to likelihood of failure, and for some assets, failure can have a negative impact on safety. Public safety risk is greatest for classes of assets that are situated near people, particularly overhead line assets.

ASSET-RELATED SAFETY RISK

Since our last AMP, we have actively improved our capability in forecasting asset safety risk (see Chapter 11). As we carry out asset replacements and renewals, we calculate the corresponding improvement in risk. This enables us to check the efficiency of our renewals programmes and associated targeted utilisation of capital with respect to managing and treating asset safety risk.

During the CPP process we also introduced a Safety Delivery Plan, which outlines how we will reduce safety risks across our network.

KEY STRATEGIES & INITIATIVES

We aim to deliver our safety objectives by:

- Continuing to implement our safety-in-design process
- Continuing to analyse asset risks by safety consequence and defining adequate controls, including reviews of ICAM and root cause analysis findings against existing risk analyses
- Prioritising our asset renewal programme on asset fleets having the greatest inherent risk
- Delivering our integrated health and safety strategy, which will elevate our critical risk management and assurance processes
- Continuing to focus on Visible Felt Leadership
- Continuing to implement the asbestos management and removal programme
- Improving the reporting of hazards and near-miss incidents and their application to our critical risk framework
- Completing our current prioritised programme to replace assets that present a risk to the public or to our service providers
- Promoting public awareness of safety around our network
- Enhancing our approach to safety-in-design, working closely with field service providers to encourage innovation in reducing manual handling

6.2.2. Reliability

KEY STRATEGIES & INITIATIVES

While safety performance has naturally formed the main focus of our attention during the initial years of the CPP, our success in this area has recently allowed us to broaden our focus and give greater attention to reliability.

As we progress, we anticipate gradual improvements in reliability – which is borne out by the overall improvement we have seen in reliability performance in recent years. This said, we recognise that we are only just beginning to target this objective and there are still areas experiencing higher levels of unplanned outages.

In 2022, we initiated a project to identify these areas, which we've termed 'reliability hotspots'. These hotspots are pinpointed based on factors such as network SAIDI/SAIFI, the average number of outages per ICP, and outages per 100 km of network length.

For all hotspot areas, we have conducted further analysis around reliability performance to identify areas of concern and, where action is required, to develop practical solutions that deliver meaningful improvements. We engaged with customers in hotspot areas to provide information about ongoing work and future improvements in their area. In 2024, we have taken steps to further refine our approach to hotspots feeders. See Appendix D for a list of changes and the expected benefits.

6.2.3. Affordability

We understand that the affordability of our service will be different for each customer; and in this context, it is difficult to strike the right balance between level of service and affordability for all customers. Our affordability objective ensures we consider the impact of our asset management decisions on affordability for all customers.

KEY STRATEGIES & INITIATIVES

Our AMP planned expenditure seeks to maintain a balance between the desire to minimise price increases today and the need to deliver safe and reliable network services over the long term. Fundamentally, we need to maintain an adequate level of network investment not only to ensure we meet the required performance levels, but to avoid the need for significant reinvestment in future years. To ensure we get this balance right, we have identified the following strategies and initiatives:

- We will develop a set of enduring measures to monitor our success in delivering services that are affordable and represent value for money to consumers and stakeholders.
- We will optimise our cost performance through process and capability improvements.
- Recognising that our consumers are diverse and value a range of price-quality trade-offs, we will look to tailor our consultation processes to understand their preferences.
- During the CPP period, we are committed to making improvements to our cost estimation capability. Our Cost Estimation Improvement initiative is supporting greater accuracy in terms of project costs, which is enhancing our planning and forecasting processes. The enhancements come through more robust documentation of scoping requirements at various stage gates (defined by which year in the pipeline the project is planned) and more robust review processes. We have identified further improvements to expand on work completed to date, including better alignment between cost estimation building blocks and the standard schedule of rates used in the tendering process for major projects. By ensuring that we have more accurate project cost estimates and scoping, we are better informed to assess trade-offs around cost and risk, and are thus better equipped to optimise the plan.

6.2.4. Responsiveness

The *responsiveness* objective addresses the need for network improvements to address changes in technology and in electricity usage, and we have begun to increase our focus in this area as we take no-regret actions to prepare for the future.

KEY STRATEGIES & INITIATIVES

To ensure we can effectively respond to the opportunities and challenges we will face over the AMP planning period, we have developed a set of initiatives, including:

- Monitoring the preferences and expectations of consumers through surveys and consultations

- Engaging with leading industry and academic groups to enhance our approach to asset management and new distribution network operating models
- Building skills related to innovation, research and development, piloting new solutions, and developing these to a level of maturity suitable for incorporating into 'business-as-usual'
- Managing and effectively analysing increasing volumes of network and asset data
- Increasing the use of scenario analysis to inform our long-term planning
- Developing our asset management competency, including collaboration with industry peers to provide new challenges and allow staff to develop new skills
- Developing a comprehensive roadmap for ICT solutions to support network operations
- Building a 'learning' approach to asset management and operational decision-making
- Enhancing our consumer-facing capabilities so we can better understand consumer requirements and emerging trends, and how these could be reflected in our decision-making

6.2.5. Sustainability

We introduced our sustainability focus in our 2023 AMP. Thus, we are still in the process of establishing standard requirements and measures of performance throughout the business. In the future, we expect to report on our performance in this area as we monitor our progress.

KEY STRATEGIES & INITIATIVES

To support an increased level of sustainability practice within our business, we have developed a Waste Reduction Strategy and an Emissions Reduction Strategy. These strategies formalise our approach to reducing waste and emissions, articulating our commitment in these areas and providing an action plan with targets for us to achieve.

Our overall sustainability strategy includes the following initiatives:

- Managing the environmental aspects of our assets by considering use of available space, resource consents required, constructability, resource availability, and equipment materials and manufacture
- Assessing environmental risks through investment options and maintenance approaches
- Limiting negative impacts from insulating mediums (e.g. oil, SF_6)
- Extending investment analysis to include noise pollution and visual impact
- Over time, aiming to reduce our carbon footprint by reducing emissions related to our activities and investigating ways to further offset any remainder (e.g. tree planting)
- Reviewing tenders from the perspective of environmental impact associated with the manufacture of assets and materials
- Managing disposal practices for end-of-life assets, including responsible handling of recyclable and hazardous materials
- Encouraging sustainable energy solutions in the regions we serve, including defining workable criteria and conditions for sustainable generation (DER) and enabling adoption of EV transport

6.3. ASSET MANAGEMENT GOVERNANCE

Asset management governance is our term for the system of roles, responsibilities, authorities, and controls that support our asset management decision-making.

Asset management decision-making occurs at various levels in our organisation, from the Board through to our planning and delivery teams. Key asset management responsibilities across our organisational structure are shown in Figure 6-5.

DELEGATED AUTHORITY

Our Delegation of Financial Authority Standard (AE-SA11-S) sets out the limits to which employees can commit Aurora Energy to financial transactions or contractual obligations, managing the exposure to financial risk. The limits assigned to a role reflect whether the expenditure is capex or opex, budgeted or unbudgeted.

6.3.1. Our Board

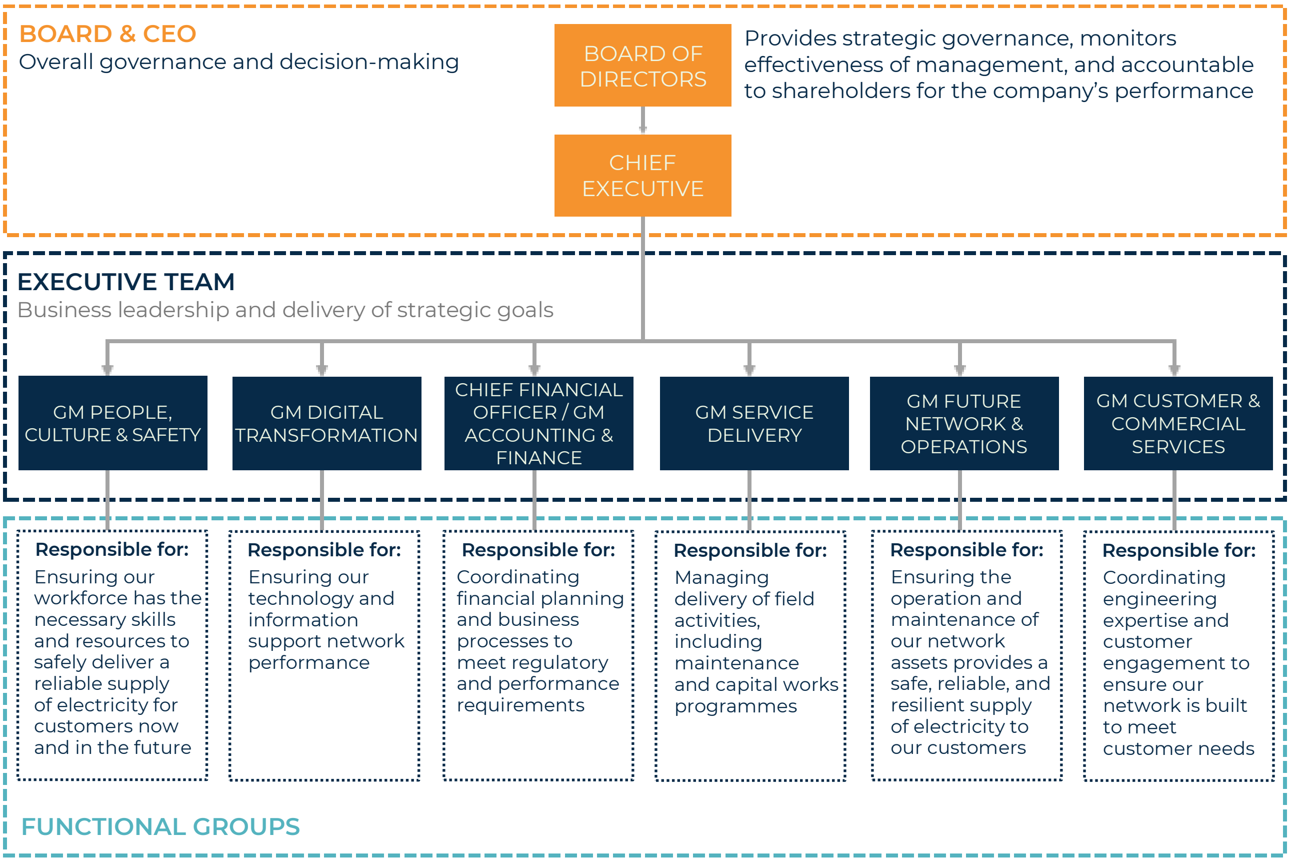
The main asset management responsibilities of the Board are:

- Reviewing and approving our AMP and ensuring it meets regulatory requirements
- Assuming overall accountability for maintaining a safe working environment and ensuring public safety is not compromised by our assets and operations
- Approving projects or programmes with expenditure greater than $0.5 million
- Reviewing performance reports on the status of key work programmes and important network performance metrics, to provide guidance to management on improvements required or changes in strategic direction
- Taking responsibility for overseeing risk management practices. The Board also reviews reports by external auditors.

6.3.2. Our Executive Team

Like most organisations, support is provided by an Executive Team of general managers (GMs), each responsible for a functional area of the organisation. Core responsibilities of this team include delivering the organisation's strategic goals and providing advice and leadership to the wider business. Each GM oversees one of the seven functional groups depicted in Figure 6-5.

Figure 6-5: Asset management responsibilities



6.3.3. Day-to-day management of our network

The primary responsibility for the day-to-day management of our network lies with the teams listed in Table 6-2 on the following pages.

Table 6-2: Asset management roles and responsibilities

Functional group	Team	Key asset management responsibilities
Customer and Commercial Services	Strategic Capacity	Strategic network investments Transpower planning interface Grid Exit Points and Transmission Lines Strategic future network innovations with commercial implications
	Engineering	Technical support to projects including design reviews Leading the development and review of design standards Scope for customer works and major projects (where applicable) Protection modelling in network model Power quality monitoring and incident review New equipment assessment Safety-in-design Technical specifications Developing scopes for planning and replacement where appropriate
	Network Commercial Services and Solutions	Managing new customer connections Administering DG applications Forecasting customer connection expenditure
	Customer and Engagement	Input into job planning, as the customer advocate Feedback into decision-making via annual customer satisfaction surveys and community engagement Communications and engagement programme to keep customers proactively informed of network maintenance and upgrades, and to provide feedback channels
Works Programming and Delivery	Works Delivery	Delivery of network capital programmes/projects Delivery of maintenance programme Delivering standard and strategic customer-initiated works
	Programming & Scheduling	Programme/project expenditure reporting Programme/project scheduling Oversee work programming and service delivery portfolio
	Contracts Performance	Negotiate service provider contracts Develop and manage supplier relationships with Field Service Agreement (FSA) partners and other contractors Maintaining contractor management plans Contractor performance Contract management (extensions, variations, renewals)
	Network Procurement	Procurement of major plant and network equipment Critical spares process Preparation and evaluation of tender programme
People, Culture and Safety	Health & Safety	External field auditing of contractor health and safety performance Site interactions Contract schedules with specific H&S requirements Safety-in-design requirements Prequalification Ethical suppliers
	People and Culture	Identifying required skillsets and competencies for building, maintaining and operating the network, and recruiting accordingly Managing and balancing staffing levels within financial and regulatory limits Preserving and extending institutional asset management knowledge through training and career development programmes

Functional group	Team	Key asset management responsibilities
Future Network and Operations	Asset Lifecycle	Asset lifecycle strategies Preparing plans/scopes aligned to asset lifecycle strategies Monitoring and interpreting asset condition Risk assessment Identifying assets for intervention Scope asset intervention ready for implementation Developing asset maintenance and replacement plans Asset specialist support to design teams Optimisation of planning and lifecycle network expenditure forecasts Lead network reliability/performance forecasting Lead the development of specifications for risk management and quantification Lead asset management development planning Coordinating AMP preparation and Asset Management Maturity Assessment Tool reviews Lead the development of Asset Management Strategy Vegetation management
	Network Planning	Load forecasting Network HV power flow model maintenance Fault studies and low voltage (LV) network modelling Demand-side management and emerging technology strategy Security of supply guide Standards and guidelines for HV/LV network architectures Property and asset relocation planning Transpower planning interface Contingency planning Development of long-term network expenditure forecasts
	Network Access	Outage planning and work scheduling Assessment and prioritisation of planned outage requests Notifying planned outages to retailers and consumers Authorisation of third-party 'close approach' Coordination of oversized transport movements
	Network Operations	Network Operations Centre (NOC) Real-time network management (system monitoring, switching and load control) Contractor access permits Operational resilience Emergency management Fault restoration coordination
	Operational and Public Health & Safety	Incident management processes Public safety management
	Operational Performance & Operational Technology	Network event and major event day investigation and review Monitoring compliance with reliability and public safety obligations Advanced Distribution Management System (ADMS) Outage Management System (OMS) Rapid response (public safety risks)

6.4. EVIDENCE-BASED DECISION-MAKING

DECISION-MAKING APPROACH

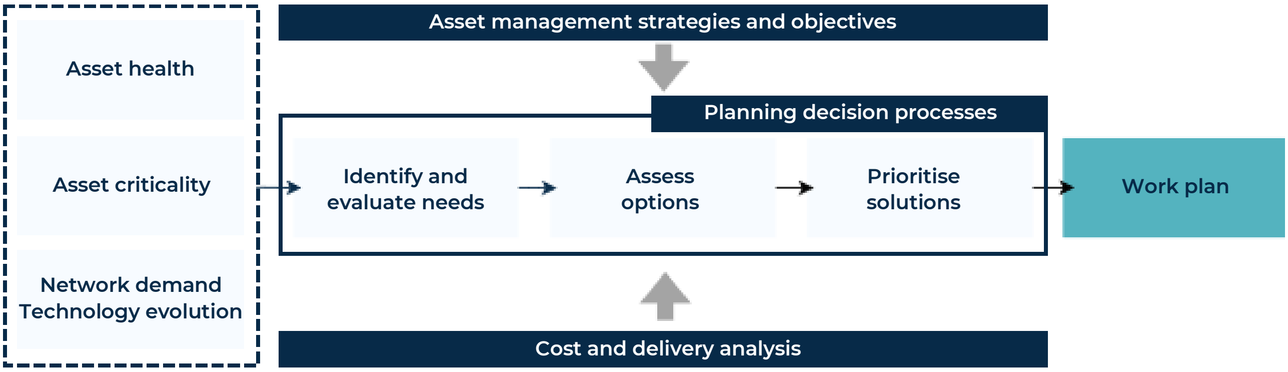
Our approach to asset management decision-making uses processes that test our individual planned expenditure and our overall expenditure. We are continually working to improve the data or information available to us. We test and refine its completeness, quality, and relevance against emerging insights from actual performance and failure of our assets on our network.

By doing this, we are seeking to ensure investment needs are validated with actual data or evidence. This is an approach that we are maturing, with active workstreams including but not limited to improved inspection standards and root cause analysis on faults.

Investment decisions take place within a system of responsibilities and controls that reflect the cost, risk, and complexity of the decision being considered.

Our systematic decision-making approach for network expenditure is shown in Figure 6-6.

Figure 6-6: Decision-making approach



The main steps in our investment decision-making process are described in Table 6-3. The degree to which these steps have been formally adopted varies across our expenditure categories.

Table 6-3: Investment decision-making process

Process step	Description
Identify and evaluate needs	Involves the systematic review of asset safety, network capacity constraints, network security, performance, asset health, maintainability, spares availability, and a range of technological, network and site-specific feedback.
Assess options	Potential options are developed for each identified need. These options are defined and costed to varying degrees based on the complexity and scale of the identified need and the costs of feasible solutions. The potential solution is evaluated against approval criteria and challenged.
Prioritise solutions	Solutions that have been developed in previous stages or previous planning rounds are prioritised based on the risks associated with the identified need, deliverability, across-project coordination, and trade-offs with other expenditure needs. A preferred solution is identified that may include bundling of multiple needs into one packaged solution.
Draft work plans	The prioritised solutions are entered into a draft work plan that sets out planned works with the associated expenditure forecasts. The deliverability of the overall set of solutions is evaluated in more detail, and cross-portfolio expenditure balancing is undertaken if required.

INVESTMENT APPROACH TO INNOVATION

The accelerating pace of new technology development and the changing environment in which we operate require us to actively consider new ways of meeting our business and asset management objectives. New consumer technologies create new challenges for us, but they also create opportunities. Our innovative and collaborative work with solarZero over the last few years to utilise consumer-owned battery technology to reduce peaks on the network has been an industry-leading example of innovation. This initiative required an innovative contract and systems operations capability to manage resources in real time.

Our approach to innovation varies depending on the maturity of the solution or opportunity. In some cases, a pilot or a trial is required to ascertain whether an innovation achieves the benefits indicated by a desktop review. In other cases, the benefits are more certain and implementation risks relatively low, so the innovation may progress directly to full implementation following a comprehensive assessment of the opportunity.

While we propose further development of our assessment process for innovative initiatives, the high-level investment/assessment test is not dissimilar to our traditional investment assessment, including an assessment of whether the innovation can:

- Deliver benefits greater than the cost – for example, improved reliability performance at a cost acceptable to consumers
- Assist with delivery of our business and asset management strategic objectives
- Create cost savings through improved efficiency without a degradation in service
- Better manage intolerable risks

Furthermore, our innovative assessment criteria must consider the potential for the innovative practice to:

- Introduce new risks – for example, through increased uncertainty of outcome or unsupported technologies
- Provide scalability and alignment with sector/vendor strategic direction

Post-pilot/trial reviews consider the above investment test factors before wider implementation or abandonment.

Many innovation opportunities depend upon third-party collaboration or vendor product/ service development. This can make scoping and timely implementation challenging and lead to a need for extensive in-house resource to manage and influence outcomes, including seeking industry strategic alignment.

In addition to the ongoing innovation associated with the procurement and management of non-network solutions, we presently have five innovation initiatives underway, at various stages of implementation:

- **LV hosting capacity AND LV CAPEX modelling** – The Ara Ake EDB challenge helped improved ANSA's hosting and LV Capex model in determining low voltage network hosting capacity, constraint forecasting, and network reinforcement budget forecasting. Following completion of the EDB challenge, we conducted a hosting capacity study with updated LV GIS data and using more smart meter consumption.

  Low voltage network visibility platform – The aim of the platform and associated analytics is to enable better planning and operation of our low voltage network. However, with the unexpected high cost and long contract duration associated with procurement of smart meter network operating data, we are progressing with business cases for procuring smart meter network operating data and an LV visibility platform, to inform our investment decision to move forward. We have progressed an ROI and RFP for the procurement of a platform with ongoing collaboration and innovation toward the development of new capabilities and use cases.
- **Early fault detection system** – This technology has been very successful in the context of a trial on the Omakau 33 kV supply line to detect emerging faults and prevent outages. We have identified and proactively responded to a number of emerging faults, but are yet to quantify the dollars 'saved' as a result of this system (see Section 11.4).
- **Leaning pole risk assessment** – In collaboration with other EDBs we developed a scale pole model to aid our assessment of leaning pole failure risk. This led to an adjustment in our risk assessment and resulting criteria for pole intervention/ remediation in RY25 (see Section 11.3.1).
- **AI and Satellite based vegetation management** – We are at the early stages of assessing the role of satellite imagery and AI to help us transition from a cyclic vegetation management programme to a risk-based approach. While this technology is maturing globally and may not be considered innovative, we will need to be innovative in the development or application of the 'off the shelf' service to adapt it to the NZ Tree Regulation

requirements. We will need to assess whether a modified version meets our investment test criteria.

6.4.1. Asset information and data to support decision-making

ASSET DATA REQUIREMENTS

In our journey toward greater asset management maturity, we are continually reviewing the data we need for our evidence-based decision-making approach.

We acknowledge that our ability to optimise our investment decision-making processes is founded on the data inputs that inform our decisions, and that good asset management is reliant on the ability to continually improve and adjust our approach as new information comes to light. The following are some of our day-to-day continual improvements regarding data quality:

- Responding to new information obtained through inspections, defect identification or investigation of failures, by updating fleet strategies and inspection criteria
- Developing and reviewing inspection guidance and standards to obtain more relevant source data and improve its quality and consistency
- Advancing internal tools and systems to enable better visibility and analysis of data
- Creating a roadmap of opportunities to manage out inconsistencies and human error in the data gathering process

Before we can start collecting data for consumption within the business, it is important to clarify exactly what data and business rules we require to support our decision-making. Thus, as a part of our project to implement an asset management software solution (discussed below), we are identifying and documenting our key asset and network-related data requirements, with a focus on:

- **Static (or master) data** – such as installation date, manufacture date, and material type
- **Dynamic data** – such as asset condition

Viewed together, data of this nature will enable us to evaluate asset performance in terms of risk and in turn determine what types of assets we install, when, and where.

ASSET DATA COLLECTION

With clearly defined asset data requirements, we will be in a better position to optimise our asset-data lifecycle, which necessarily starts with the collection of data at the source.

We contract the delivery of our works programme to our field service providers. While we need to clearly communicate what data we need those field service providers to collect, we also need to give them data quality guidelines and measures that will enable them to capture that data and provide it to us in a uniform, streamlined way.

To improve the way in which our data is collected and minimise the need for manual intervention, we have developed an integration platform for our field service providers to use. This platform is context-specific to ensure the field service providers provide consistent sets of information.

We also recognise the importance of receiving our asset data in a timely manner. To improve the timeliness of our data capture, we plan to work with our field service providers to introduce key performance indicators to improve the timeframes within which field-based staff capture and provide asset-related information.

ASSET DATA STORAGE

We currently use the following systems for storing our asset data:

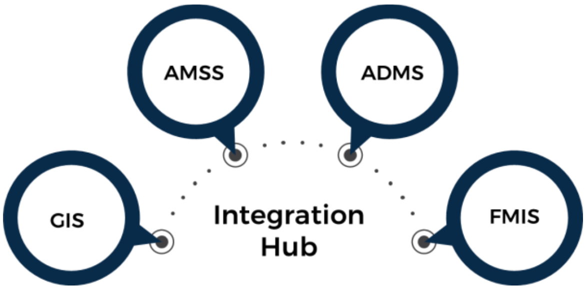
- **Geospatial information system (GIS)** – which we use for geospatial information
- **Advanced Distribution Management (ADMS) and Historian** – both of which provide real-time operational characteristics
- **Financial Management Information System (FMIS)** – which provides financial data in relation to assets (for example, asset value and depreciation information)

In addition to the above, we are in the process of implementing an asset management software solution (AMSS). This will be the repository for our static and dynamic asset data. Integration of our AMSS and FMIS has progressed, enabling seamless capture of asset work order information including asset type, expenditure category, and cost information.

This integration enables us to efficiently and accurately track and report the costs and asset quantities associated with projects and programmes of work, which is a key requirement of our CPP Annual Delivery Reporting.

To integrate each of these stand-alone systems, we are using a third-party integration hub as shown in Figure 6-7. This will ensure referential integrity between asset information in each of our core systems.

Figure 6-7: Integration Hub



Each of the core systems is 'best-of-breed', with a smaller scope than an enterprise resource planning solution, which minimises the amount of business change necessary for each phase of the transformation. As each system is enhanced, it only needs to be integrated with the integration hub, thus avoiding disruption to the other core systems.

Similarly, as changes are applied to the GIS, FMIS and ADMS, integration changes will be limited to the integration hub, thus minimising the impact on other systems and their related business processes.

Once in place, this integrated structure will support and enforce digital-only data capture by our field service providers.

DATA MANAGEMENT

It is important that we have robust data management practices throughout the lifecycle of our information, from identification of need, through creation, quality assurance, maintenance, reuse, and ultimately to archiving or destruction once the information has ceased to be useful. To ensure we have good quality data on our assets, we will improve our internal practices that underpin key parts of the data capture process. This will include:

- Implementing a range of policies, standards and processes to ensure availability and integrity of data
- Improving the ways in which we clean up our data
- Implementing data management controls
- Implementing data audits

DATA REPORTING

To support more robust analysis and advanced asset-related reporting, we will introduce new analytical tools into the business. While the quality of the analysis will at first be limited by the quality and availability of source data, we expect to see this improve markedly over time as we implement new controls. The value of our asset analytics should also improve over time as we continually grow our library of historical asset information.

By introducing new analytical tools, we will be able to tailor reports to specific business needs. This will take place in line with a business intelligence and analytics framework that we plan to introduce to support internal reporting and consumption of data.

The following components will be essential to that framework:

- Creating an internal centre of excellence, which includes building capability within Aurora Energy and developing a solid foundation for dashboard reporting
- Creating dashboard delivery capability

ASSET DATA LIMITATIONS

As described above, the key limitations in terms of asset data relate to the quality and availability of source data. In conjunction with the implementation of IBM Maximo as our asset management software solution, we are working on improving the accuracy and completeness of our master data.

By reviewing and redeveloping the content of our data collection forms and supporting standards, we will reduce the workload for inspectors and allow them to focus on the key data points, while increasing the consistency and repeatability of inspection data. Over time, we expect these measures to result in more consistent and reliable asset data.

Progress against our Asset Data Collection and Asset Data Quality Development Plan is detailed in Appendix D.

As we mature in our approach to asset management, we are continually checking, refining, and building upon the data we gather and use to inform our investment decisions. Table 6-4 provides examples of data limitations and the work we are doing to improve our data and how we use it.

Table 6-4: Data limitations and improvements

Fleet	Limitation	Improvement
Crossarms	Data completeness and data quality; system capability	Testing of a sample of condemned crossarms and a review of the incoming data indicated that the previous mobile inspection application and assessments were not reliable. In response, we developed the new Overhead Inspection Standard and inspection app and made appropriate adjustments to our investment plan. While we do yet not have a full (5-year cycle) set of data, we have increasing confidence, and as such have significantly reduced the forecast rate of replacement.
Overhead conductor	Data completeness and data quality	We have completed and rolled out a new inspection standard, with approximately 30% of the fleet inspected as of writing this AMP. This has been accompanied by sample testing of recovered assets to validate a desktop evaluation of remaining life.
Ground-mounted switchgear and distribution transformers	Data completeness and data quality	We have completed and rolled out new inspection standards for distribution transformers and switchgear, incorporating a strategic review of inspection needs and frequency.
Buried cables – LV & distribution	Data completeness and data quality	A strategy for inspections and validation of age to end-of-life are required to inform renewal strategies.

6.5. ASSET LIFECYCLE MANAGEMENT

To ensure we maintain a safe, reliable and resilient network, we apply a whole-of-lifecycle approach to the management of our assets.

We use the term 'lifecycle' to recognise that there are distinct phases in the ownership of an asset, whereas the term 'management' describes our custodianship of an asset. We realise that effective asset management relies upon a holistic approach that considers the full asset lifecycle. Below, we list some considerations that inform our decision-making for asset lifecycle management.

- **Practical and safe operation:** Decisions made at the concept and planning stages consider the operational implications of each asset and how these impact worker and public safety over the asset's life.
- **Operational thresholds and maintenance requirements:** These are identified and captured to ensure the value of an asset is maximised.
- **Whole-of-life investment optimisation:** Investment options consider operational, maintenance, and refurbishment costs over the expected life of the asset.
- **Future trends:** The way electricity will be delivered to consumers in the coming years is a topic of great debate. With the life of assets measured in several tens of years, decisions around their lifecycle must be robust and as future-proof as can reasonably be expected or forecast.

Figure 6-8: Asset management lifecycle

6.5.1. Network development

We use the term 'network development' to describe capital investment aimed at increasing network capacity or improving network security and reliability. Network development also includes investment for customer connections and for network upgrades to meet changes in technology brought on by decarbonisation.

New development is covered in Chapter 9 and Chapter 10. These chapters outline how we identify development needs and the key initiatives and projects we will undertake. We then have processes for designing and constructing these new assets.

6.5.2. Design & construction

Work that is approved in the network development stage flows into the design and construct stage. At this point, capital projects are handed over from our network planning team to the delivery team.

The main activities in this phase (discussed below) include:

- Detailed design
- Procurement
- Construction
- Project management
- Commissioning
- Handover of new assets to operational teams

These activities are managed by a dedicated project manager who is responsible for ensuring the work is delivered on time, per specification and within budget.

DESIGN PROCESS

Depending on the type and complexity of the work, detailed designs are developed by our design team, contractors, or design consultants. Detailed designs identify construction methods to minimise risks to safety and reliability, and are important in larger projects for controlling cost, quality, and timelines.

Design reviews take place at various stages of a project. They cover safety, adherence to standards, technical requirements, and completeness. Inputs for design reviews are considered from all departments.

Our design approach aims to standardise our network assets through the use of a suite of design standards and standard designs. This approach works well for typical installations and smaller defect jobs, providing efficiencies in design, construction, maintenance, operations, and spares management. It also facilitates a greater emphasis on safety-in-design, which is a key driver for our design standards.

To this end, our Distribution Engineering team has been working through a programme to expand its library of standard designs for support structures, pole-mounted switchgear, and more recently, distribution transformers.

All design, construction and maintenance standards, procedures, forms and drawings, are managed in our Controlled Document System (CDS) and our drawing management tool, RedEye. Once approved in accordance with Aurora Energy's Controlled Document Management Standard (AE-AC01-S), such documents are made available online to our service providers.

To further enhance Aurora Energy's control over standards, the organisation established the role of Engineering Standards Manager in RY23. This step toward setting up a specialised team with responsibility for standards and related documentation and processes has helped us move toward long-term consistency across our network.

Improved standardisation brings efficiencies from the perspectives of spares management and configuration and helps reduce training requirements and ensure our service providers can source maintenance technicians with the requisite competencies.

PROCUREMENT & CONSTRUCTION

Our procurement and construction activities are central to delivering efficient, reliable services. A principal strategy to promote cost efficiency involves the implementation of standardised assets and designs, as detailed in our Procurement Standard. This approach ensures uniformity and scalability across our operations, directly contributing to cost reductions and enhanced network efficiency.

In the procurement phase, we apply these principles by favouring standardised solutions wherever feasible. This not only streamlines our procurement process but also reduces long-term operational costs through increased compatibility and ease of maintenance. Standardised designs are incorporated into our tendering documents, providing clear guidelines for service providers and aligning their work with our efficiency goals.

Quality control remains a top priority to ensure safety and effectiveness throughout the asset's lifecycle. Our service providers bear the primary responsibility for quality during commissioning and construction, whilst we conduct regular checks and inspections to confirm adherence to our standards and safety protocols.

These measures are essential for maintaining the integrity of our standardised assets and confirming that the scope of work aligns with our efficiency objectives.

Managed by our project managers with a mixture of internal and external expertise, this approach to procurement and construction helps us achieve greater cost efficiency and network optimisation as we aim to maximise network utilisation and minimise operational losses.

6.5.3. Operate & maintain

Once an asset is commissioned and put into service, the operate and maintain stage commences. Many assets have a practical life span of 40 to 60 years, which means this stage has the longest duration of the asset lifecycle.

By monitoring and proactively maintaining our assets in a condition where they can operate safely and economically, we maximise operating life and return on investment. Our approaches to operating and maintaining our assets are outlined in Table 6-5.

Table 6-5: Approaches to operations & maintenance

Approach	What this includes	Key strategies
Network operation	Includes system monitoring, switching and load control, risk management, fault response coordination, and providing contractors safe access to the network for works required to develop and maintain the assets.	Constant communication with contractors, generators, retailers and electricity consumers
Preventive maintenance	Typically, encompasses programmed activities that are carried out on a regular basis. Inspection periods for each fleet are set in accordance with manufacturer's recommendations and our maintenance standards. Recorded condition assessment data is used for analysis, forecasting and renewal planning and to drive defect and repair work (corrective maintenance).	Inspections Condition assessments Servicing
Corrective maintenance	Encompasses planned work arising from preventive maintenance reporting, ad-hoc identification of defects, or as a follow-up to a fault. It includes defect rectification, repairs, and replacement of minor components to restore the condition of an asset. Prioritised and scheduled as determined by engineers.	'Rapid Response' and rectified within 90 days
Reactive maintenance	Includes fault response and emergency switching carried out in response to an unplanned event or incident that impairs normal network operation. Failure to undertake this work in a timely manner can adversely affect both the service provided to consumers and the long-term health of our assets and may increase public safety risk.	Reactive work is dispatched by the control room in response to network events including adverse weather events, indication of imminent asset failure, asset failure, and third-party interference
Vegetation management	Ensures that trees are kept clear of our overhead lines. By proactively monitoring our network, we minimise vegetation-related outages and meet our safety and statutory obligations.	Proactive monitoring inspections Liaison with landowners Tree trimming and removal
Spares management	We keep a pool of spare parts for our assets on order to minimise downtime for common faults and hard-to-source items. These are located as appropriate for the assets they cover. We categorise replacement parts as either strategic or critical spares. The number and type of spares retained for each asset family varies depending on asset usage and lead times for returning the network to operation. Spares management is complex for any business operating legacy equipment with a wide spectrum of different makes and models in service.	Spares inventory with standardised equipment manufacturers, types, and ratings Contractual arrangement with FSA contractor to manage spares

KEY DRIVERS

The key drivers for maintenance planning are:

- **Asset management system:** Timely information on assets is essential for making cost-effective decisions.
- **Manufacturers' recommendations:** For inspection tasks and servicing intervals.
- **Legislative or regulatory requirements:** Including minimum frequencies for inspecting overhead line assets.
- **Fault numbers:** Where assets require second response work.
- **Maintenance standards:** Specifying recommended maintenance inspection tasks, servicing intervals, and reporting requirements.
- **Asset condition:** As identified by preventive maintenance activities.
- **Asset types:** Assets of different types and manufacturers have unique characteristics. Some types fail more often than others, and some are replaced upon failure (e.g. fuses), while others are replaced proactively.
- **Number and location of automation devices:** Remote devices help reduce event impact, such as by remotely sectionalising the network, thereby speeding up restoration and reducing impact on SAIDI.
- **Location of faults:** Rural, remote-rural, and mountainous areas require additional travel time to address faults.
- **Third-party:** Incidents such as car versus pole and cable strikes caused by third parties lead to outages and potential safety risks.
- **Environmental conditions:** Overhead assets in particular are more prone to failure in corrosive or high wind locations or in adverse weather. Snow and ice can also increase faults due to additional structural loading on overhead lines.

The volume of work we undertake in other maintenance or renewal portfolios affects corrective maintenance volumes in the longer term. For example, an increase in planned renewal or preventive maintenance work on the overhead network will tend to decrease corrective maintenance volumes in the longer term because it improves the condition of assets. But in the short term, an increase in preventive maintenance may result in more defects being identified and requiring correction.

Due to constraints in asset management processes and supporting information, coupled with a focus on risk associated with assets failing in service, we have not yet completed all the preventive maintenance activities that we intended to carry out. However, during the past two years, we have been enhancing our planned maintenance programme, including creating supporting documentation and systems to introduce more holistic but targeted inspections. This revised programme of inspection will enable us to address the backlog of maintenance tasks and reach a steady state. The key stages of our asset maintenance approach are described in Table 6-6.

Table 6-6: Asset maintenance stages

Maintenance stage	Description
Planning	Information we obtain from preventive maintenance is used to plan our corrective maintenance programme.
Prioritisation	We use a criticality-based approach to prioritise assets for the corrective maintenance programme. This approach allows us to allocate our funds and resources more effectively to reduce risk and address poor performance. At present, we only have a public safety criticality framework. With the safety of the network as our primary objective, we consider this is an appropriate first step. Expanding our criticality framework in future will enable us to deliver a more risk-based approach to maintenance.
Forecasting and budgeting	To set network opex budgets, we assess the previous 10-year portfolio forecasts and update them based on targeted strategy changes, emerging asset issues and non-asset-specific trends. We then review our preventive and corrective maintenance plans using a bottom-up approach and the budgets are reviewed accordingly.
Scheduling	We schedule maintenance work based on contractor availability, prioritising critical works to ensure a smooth resource profile throughout the year.

Maintenance stage	Description
Outsourced model	We operate an outsourced contracting model. Our maintenance activities are completed by our service providers under field service agreements. Our service providers are responsible for ensuring they have sufficient resources and trained staff to undertake assigned work as per our requirements and timelines. We monitor their compliance with our requirements and retain all asset information records in-house to ensure core asset knowledge is kept within the business.
Quality management	In our CPP Development Plan for 2023 and 2024, we committed to developing a quality assurance framework for management of opex work, and in RY24 we progressed some initiatives that include provision of documented standards and training with regard to driving QA for opex work streams. We have also documented a set of requirements with respect to driving 'quality in design' in our systems change process. We aim to develop this function further as resources allow.
Feedback and monitoring	Two types of feedback are obtained using our FSAs. Technical feedback details how we can improve our maintenance documents or identification of asset issues. Work planning feedback contains programme suggestions, feedback on commitments, resource restraints, and the ability to do work.

6.5.4. Renew or dispose

RENEWAL APPROACH

We have two high level renewal strategies:

Proactive preventive: In this case, the renewal strategy is informed by the impact of failure, as currently understood. Any fleets that are deemed to have a public safety implication if they fail are renewed in a proactive way, prioritised by risk. We also deploy proactive renewal strategies when failure of an asset would lead to a significant impact on network reliability.

Reactive – run to fail: In some cases, where there is no public safety risk and minimal network security risk, we strategically plan to run an asset until it fails. The benefit of this strategy is that maximum life is achieved where risk associated with failure is low.

The fleet-specific renewal strategies are detailed in our Fleet Strategy documents.

As assets deteriorate, they eventually reach a state where the required maintenance to keep them safe and serviceable becomes ineffective or uneconomic. Refurbishment and replacement are key activities to manage risks associated with deterioration of asset condition impacting safety, network performance, asset obsolescence, and regulatory and legislative compliance.

Key considerations for renewal are outlined in Table 6-7.

Table 6-7: Renewal considerations

Consideration	What this includes	Key strategies
Safety	Renewals required to limit safety risk. Safety risk management is the highest priority for asset lifecycle investment.	Safety risk profiles (in the form of a risk matrix) are used to determine renewal programme priorities for every fleet.
Network performance	Renewals required to meet reliability targets. A near real-time reliability dashboard and reporting tool indicates performance based on network area.	We replace legacy installations that do not meet current design standards.
Obsolescence	Renewals required due to obsolescence, particularly in the secondary systems portfolio. Factors such as incompatibility, unavailability of spares and industry knowledge play a major part in obsolescence.	We are refining our asset health model to tackle obsolescence and reviewing our fleet management strategy to address the associated risks.
Renewal thresholds	Consideration of project timelines, asset and resource availability, and integration of work packages to balance network improvement, risk and cost.	The triggers for renewal thresholds are asset-specific.
Asset renewal forecasting	As assets approach the end of their service life, their replacement is triggered by asset condition or our forecasting analysis.	Investment forecast based on fleet-specific deterioration rates and maximum economic service life.
Options analysis	Detailed options analysis used for non-standard replacements (i.e. not like-for-like).	Options selection informed by technical studies, economic assessments, risk

Consideration	What this includes	Key strategies
	As an alternative to renewal, asset refurbishment or continued maintenance (the latter in most cases being the 'Do Nothing' or control scenario) are options that are considered where appropriate.	analysis, safety reviews, lifecycle cost analysis.

DISPOSAL APPROACH

Asset disposal follows the decision to remove an asset from our network, either because it is being replaced or because it has become redundant.

Disposal activities include planning for disposal, decommissioning the asset, and site restoration.

Disposal: Removing an asset from our network because it is being replaced or has become redundant

Relocation: Moving assets to align with other non-energy infrastructure development (e.g. new road realignment)

Key considerations for disposal and relocation are outlined in Table 6-8.

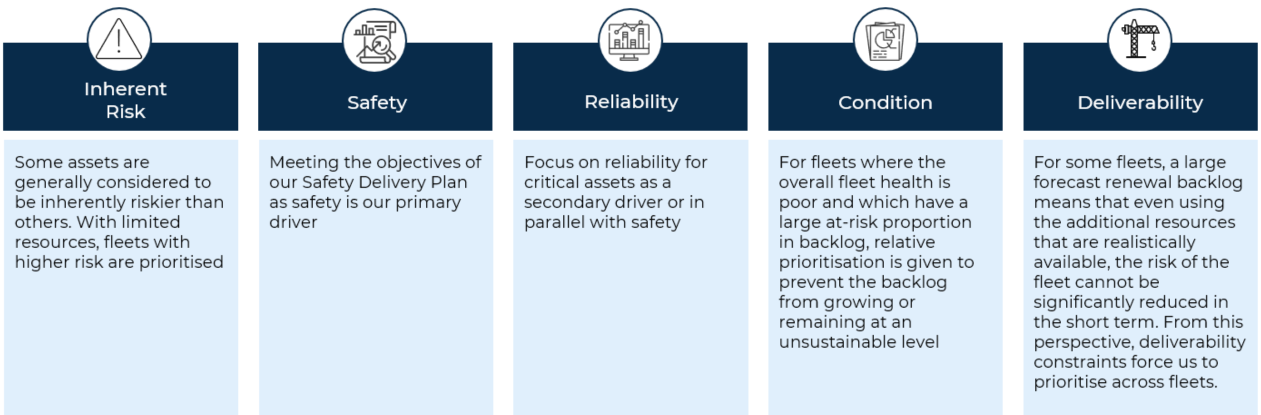
Table 6-8: Disposal & relocation considerations

Consideration	What this includes	Key strategies
Disposal options	Asset disposal works consider cost, safety, environmental impacts, project management, site restoration, termination of support activities, and removal of asset information.	Consideration of cost-effective methods of disposal and compliance with relevant regulations.
Waste management	Consistent with our safety and environment objectives, we ensure waste materials are disposed of in a responsible manner.	Consideration of special disposal requirements at an early stage in the project. Inclusion of disposal costs in overall lifecycle costing.
Site restoration & reinstatement	When assets are decommissioned and removed, part or all of a site may be able to be reused or restored.	Consideration of the impacts on health, safety, and the environment, particularly where hazardous waste is concerned.
Asset reuse/ relocation	Our assets are often located alongside other infrastructure such as roads, water pipes, and telecommunications cables. At times, the owners of this infrastructure (for example KiwiRail, NZTA, and local councils) may need us to move our assets – typically poles, conductor, and cables	Direct involvement in relocation design process with third party. For poor condition assets, consideration of upgrade at time of relocation. Obtaining contributions from third party to reduce investment costs.

6.5.5. Cross-portfolio planning approach

Our approach to rationalising lifecycle needs across all asset portfolios considers the key factors outlined in Figure 6-9.

Figure 6-9: Cross portfolio planning factors



Our fleet strategies are an innovative approach that has enabled us to create robust, risk-based renewal plans by fleet. When we look at the scenario analysis, we investigate where we can feasibly slow a renewal plan without causing undue safety risk, reliability risk, or inefficiencies in cost management.

When a renewal plan is refined such that a renewal identified in the ideal plan cannot be achieved for reasons such as financial, contractor, supplier, or internal resource constraints, we capture residual risk and controls in the fleet strategy.

We are currently investigating options to mature this process into a quantifiable risk and investment decision-making tool. Documentation of the fleet strategies – including identification of failure modes and assessment of impact – has been completed and will support the process.

FORECASTING METHODS

Asset health index (AHI) models in our fleet strategies enable us to combine asset-specific parameters such as condition, age, and expected useful life to inform our forecasts (i.e., which assets are coming to or at their end-of-life over the forecasting period). From this, we can forecast the level of investment that will be required.

Where we have adopted a reactive approach to renewals, we use historical replacement rate data to inform forecasts.

For each fleet, we create an ideal state renewal plan. We then feed this plan into a forecast for all of the business. Following a process of scenario development and analysis, the final investment plan per fleet is fed back into the fleet strategy, where the risks associated with any change are captured and appropriate controls are identified to manage any risk associated with deferral.

DEFERRAL STRATEGIES

When the ideal renewal plan set out in the fleet strategies is unattainable, we define appropriate interventions. These can include:

- Additional or advanced inspections and monitoring
- Asset refurbishment or strengthening

If we suspect or know that like-for-like replacement may not meet the future needs of the network, we implement a strategic plan for deferral of asset renewals, risk permitting, and with appropriate controls in place. Renewals are deferred until we have an appropriate level of certainty around network changes.

Our approach to rationalising needs across all asset portfolios centres on five key aspects:

- **Fleet prioritisation:** We prioritise different asset fleets based on inherent risk, focusing on those with higher inherent risk, while considering limited resources.
- **Safety as the primary driver:** Our Safety Delivery Plan is the foremost driver of our approach, ensuring the safety of our assets and operations.
- **Network performance (reliability) as a secondary driver:** We also give due attention to reliability-critical assets, aligning them with our safety objectives.
- **Network planning consideration:** Our investment approach integrates asset needs with the broader context of network development. We balance allocation with network growth and evolution, ensuring critical network development is funded adequately for the challenges.
- **Feasibility and deliverability:** We assess the condition of fleets and their backlog proportions, addressing those with poor health and significant backlog to prevent unsustainable levels. When faced with constraints such as financial limitations or resource availability, we refine our renewal plans while capturing residual risks and controls. We also give consideration to minimising interruptions by capturing work in packages, as well as ensuring the stability of the year-to-year plan with regard to sustaining workforce skills to deliver the longer-term plan.

Our fleet strategies are designed to create risk-based renewal plans, allowing us to analyse scenarios and identify where we can slow down renewal plans without compromising safety, reliability, or cost efficiency. We utilise visual representations of asset fleet risks to allocate investments adequately to qualitatively assessed risks.

Ultimately, our goal is to balance investment effectively across different portfolios to ensure the safety, reliability, and sustainability of our assets and operations.

6.6. ORGANISATIONAL ASSET MANAGEMENT CAPABILITY

6.6.1. Asset management maturity assessment tool

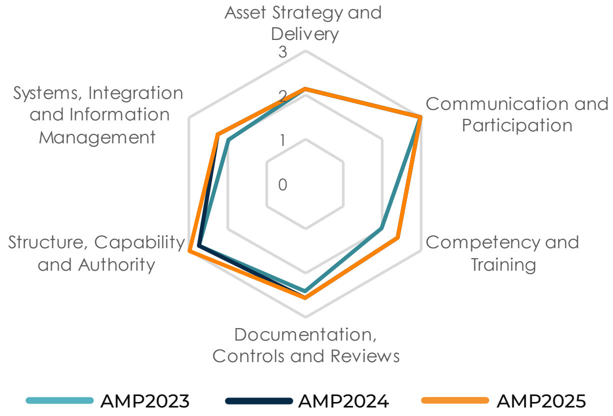
The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment undertaken by EDBs to assess how well they believe their asset management practices are developed. The tool is based on a selection of 31 questions extracted from the Publicly Available Specification 55 (PAS55) assessment methodology. PAS55 is the founding document for the ISO 55000 series of asset management standards, confirming the relevance of the AMMAT methodology. The AMMAT forms Schedule 13 in Appendix B of our AMP.

The AMMAT is arranged in six categories, with responses to each question rating from 0 (innocent) to 4 (excellent). This allows a gap analysis to be undertaken by comparing the current state against a future state, such as the 'competent' score of 3 or a more ambitious target.

We recognise the role of continuous improvement in our asset management practices to achieve our objectives. While we are demonstrating progress in some key areas, it is clear that we are not yet achieving the levels of asset management maturity that we strive for. We acknowledge that realising sustainable improvements requires a sustained effort to mature and embed enhanced asset management practices and processes enabled by technology and the capability of our people. Through a prioritised improvement plan, we are making steady progress – not all of which is captured as a step change in maturity with respect to the AMMAT scoring framework. We are focused on using our limited resources to maximise the benefits our customers see from our efforts, while ensuring we remain focused on lifting overall asset management maturity.

Figure 6-10 illustrates three areas where our AMMAT score has improved against previous assessments: Competency and Training, Documentation Controls and Reviews, and Systems Integration and Information Management. In the three areas of Asset Strategy and Delivery, Communication and Participation, and Structure Capability and Authority, there is no overall change in scoring (see note below).

Figure 6-10: Asset management maturity progression



It should be noted that, in line with the Electricity Distribution Information Disclosure Determination 2012 (consolidated July 2023), Aurora Energy uses integer values for scoring each question, only going to the next level when all requirements are met. This methodology has the effect of masking incremental progress towards overall measurable improvements in the assessed scoring. A more detailed breakdown is given in Schedule 13 in Appendix B.

6.7. IMPROVING ASSET MANAGEMENT

Our AMP25 AMMAT assessment indicates a good understanding of the core principles of asset management, with opportunity for improvement. We are cognisant of both where we have come from in our asset management journey and where we are headed. We see value in an asset management system that is aligned to ISO 55001, and we recognise that achieving this will take time and continuous improvement. To aid continuous improvement, our asset management development (improvement) plan is currently under review, from the perspective of current resourcing priorities and ensuring that effort is focused on initiatives that will enable the realisation of our purpose, thereby delivering greatest benefit to our customers as our priority.

Our current Asset Management Development (Improvement) Plan sets out a schedule of targeted improvements initiatives that continues to contribute to an overall elevated level of asset management maturity during the CPP period:

- Voltage Quality
- Customer Charter and Compensation Arrangement
- Management of Planned Interruptions
- Asset Data Collection and Asset Data Quality
- Asset Management Practices
- Cost Estimation Practices
- Quality Assurance

Collectively, the initiatives defined under these key improvement areas (Development Plan), are enabling us to extend our capability with respect to Asset Management.

To date, we have made significant progress in realising the specific initiatives. We also have a number of substantial initiatives that are works in progress and some that have been de-prioritised to optimise the benefits realised, given the resources we have available to us. Our progress against the plan is published in the Disclosures section of our website, at https://www.auroraenergy.co.nz/disclosures and a summary of progress is outlined in Appendix D of this AMP.

As we transition from CPP to DPP4, we will undertake a review of the scope of the Development (Improvement) Plan, in the context of progress made on our asset management maturity journey, and in the context of the environment we need to be prepared to operate in going forward. In the meantime, we recognise that organisational asset management capability is key to achieving or enabling the progress that we strive for in our asset management maturity, and therefore we have begun a process of mapping our organisational asset management capability within our Asset Management and Planning team.

Retaining and attracting skills that are critical to our business, as well as investing in and developing our people, are key strategic focus areas for our business. Aurora Energy has initiated a People and Culture Plan, which is currently being advanced.

KEY INITIATIVES/PLANNED IMPROVEMENTS

The following stages form the basis of our People and Culture Plan with regard to competency and training:

1. **Define the core competencies required to deliver our AMP and Development Plans**
Guided by the Institute of Asset Management Competencies Framework – which aligns with the principles and requirements of both BSI PAS-55:2008 and the ISO 55000 suite of standards – we will define a prioritised set of competencies required to ensure the success of our AMP and associated development initiatives. We will assemble a small working group to assess the specific needs and priorities of our business, and customise the framework accordingly.
2. **Develop a competency matrix for all staff**
We will develop a competency matrix to assess employees' competence against the set of competencies defined as described above. Employees will self-assess in the first instance, and identify improvement opportunities for themselves. The aim of the competency matrix will be to assess whether, as a business, we have the capacity and depth in our team to deliver both now and into the future. This includes both core business-as-usual tasks and more exceptional improvement projects. The oversight derived from the competency matrix will be used to inform resource planning, including succession planning, development plans, recruitment, and outsourcing.
3. **Develop a resource planning tool**
To understand the capacity element of the challenge, we will set up a resource planning tool so teams can plan and programme work. The tool will provide visibility to managers so they can adjust priorities on the basis of need while also giving us enhanced visibility of our progress from a largely reactive style of asset management to a more preventive approach. It will also enable us to better understand where our business can best use external resources to support the delivery of our AMP and Development Plan.
4. **Use the competency matrix to inform training and recruitment plans**
Once we have established a coherent view of the suite of competencies needed within the business against those that we already have, we will be well positioned to identify how to address the gaps. We will use this information to inform a plan to close any identified competency and capacity gaps or constraints.

EXPECTED BENEFITS

The initiatives outlined above will realise a number of benefits for Aurora Energy and our customers, including:

- Transparency on competency gaps and the ability to prioritise training
- The ability to tailor recruitment to meet our business needs
- Enhanced performance, and confidence that we can deliver upon our plans
- Clearly defined training requirements that are informed by business needs
- Maturation of our Asset Management System in line with industry standards

MILESTONES

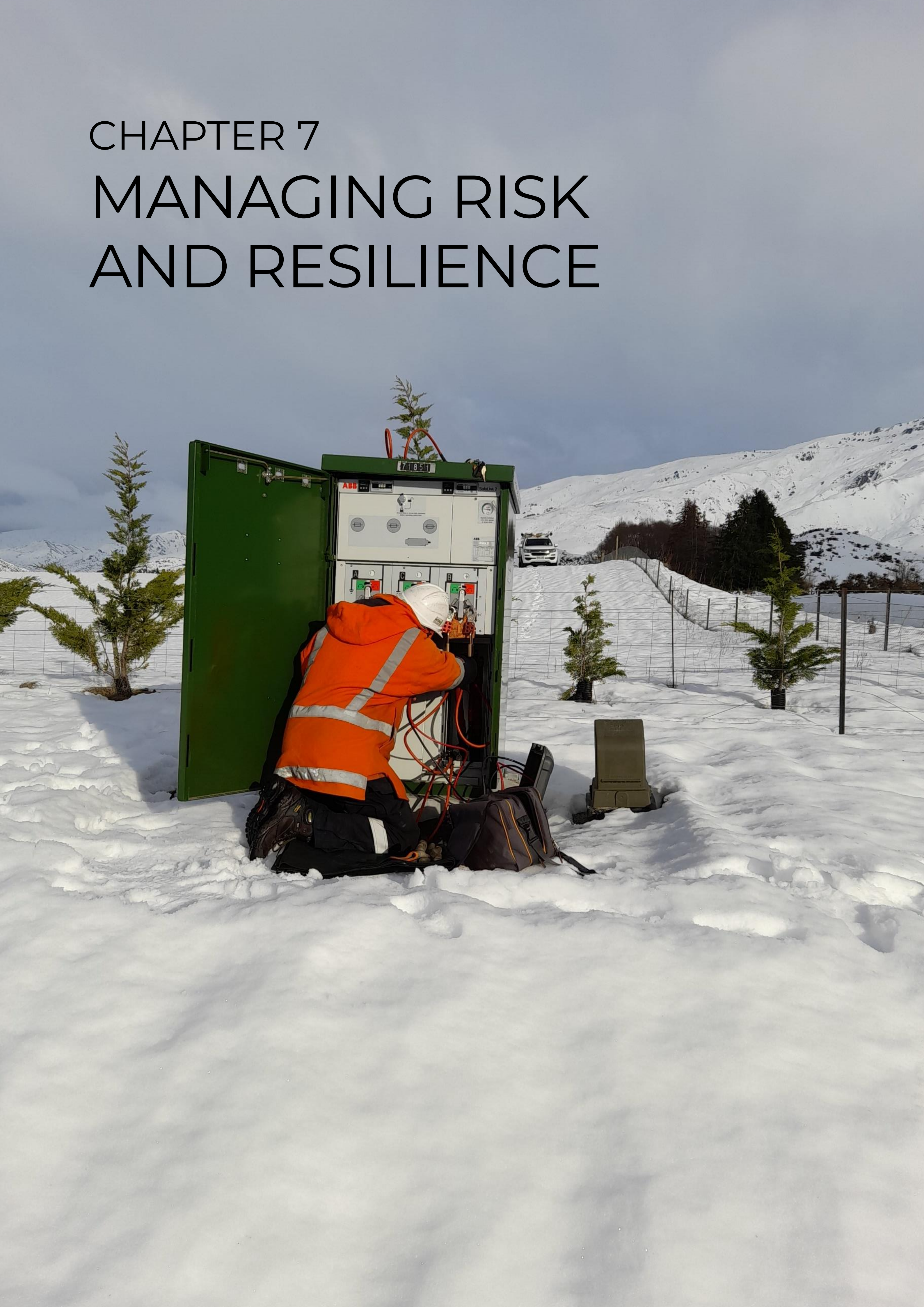
We expect this programme to be completed by the end of RY27.

Table 6-9: Competency and training milestones

KEY ACTIVITIES / MILESTONES	COMPLETION TIMEFRAME
Define the core competencies required to deliver our AMP and Development Plans	RY26–27
Develop a competency matrix for selected staff	RY26–27
Develop a resource planning tool	RY26–27
Use the competency matrix to inform training and recruitment plans	RY26–27

CHAPTER 7

MANAGING RISK AND RESILIENCE



Our asset management decisions are all linked to both managing risk and ensuring future resilience.

7.1. RISK MANAGEMENT FRAMEWORK

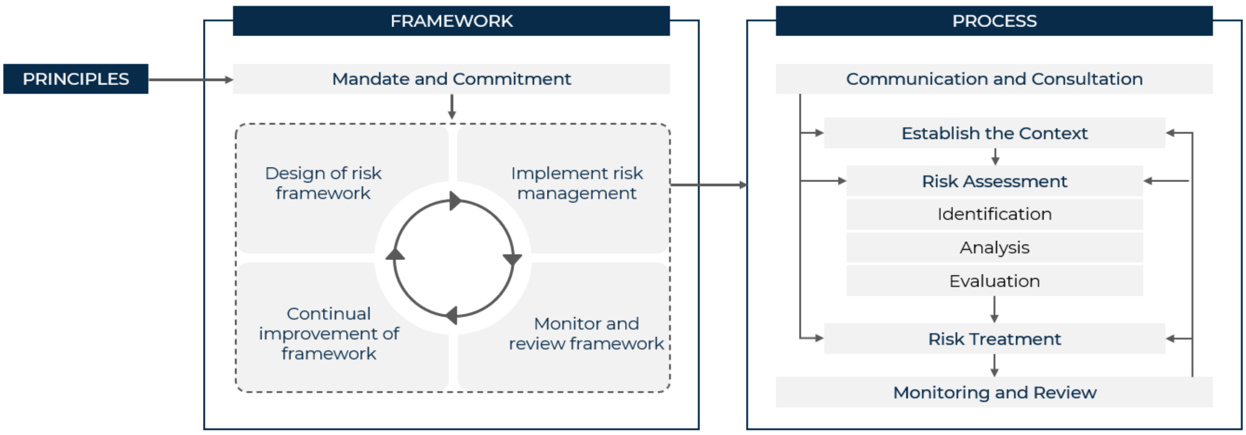
At Aurora Energy, we have an organisational risk control and management framework that enables us to manage the risks and opportunities relevant to achieving our business objectives. This ensures we take a consistent approach to the management of all enterprise risks including the health, safety and wellbeing of Aurora Energy staff, contractors working on the network, and members of the public.

Our risk management framework is consistent with the international risk management standard ISO 31000:2018 and is governed by the following principles:

- **Integration:** Risk management is integral to all of Aurora Energy's activities.
- **Structured and comprehensive:** A structured and comprehensive approach to risk management contributes to consistent and comparable results.
- **Customised:** The risk management framework is developed for Aurora Energy and is proportionate to Aurora Energy's objectives.
- **Inclusive:** Stakeholders are involved in risk management in an appropriate and timely way.
- **Dynamic:** The risk management framework is dynamic, allowing Aurora Energy to anticipate, detect, acknowledge, and respond to risks as they emerge, change or disappear.
- **Best available information:** Risks are managed based on the best available historical and current information and future expectations, while explicitly considering any limitations or uncertainties associated with such information or expectations. Information is timely, clear, and available to all relevant stakeholders.
- **Human and cultural factors:** Aurora Energy acknowledges that human behaviours and organisational culture significantly influence all aspects of risk management at each level and stage.
- **Continuous improvement:** Learning and experience improves the effectiveness of risk management.

Our risk management framework is illustrated in Figure 7-1.

Figure 7-1: Risk management framework



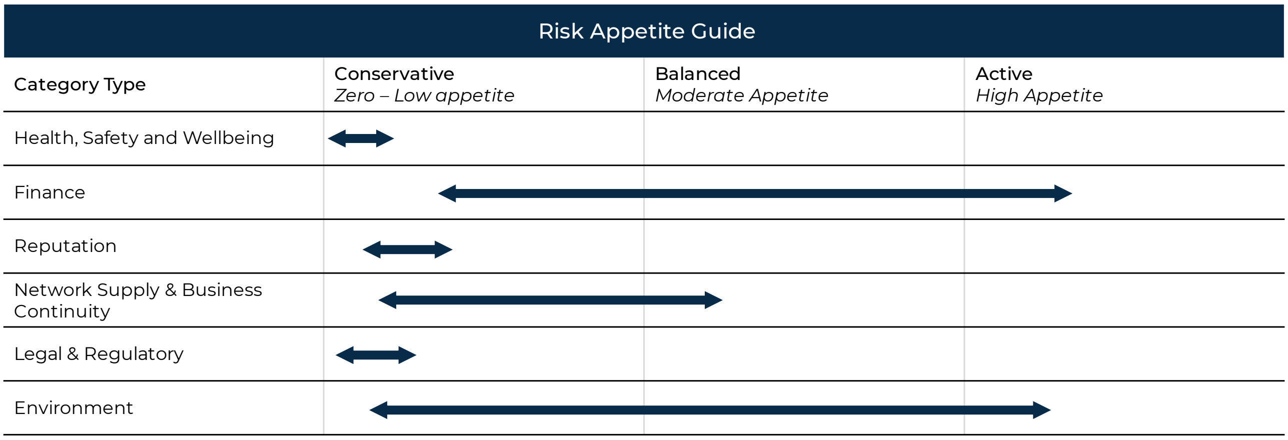
7.1.1. Risk context

We have identified 16 risk themes that align to our strategic business objectives, within which we group our critical risks. These themes represent our biggest risk areas and are outlined in Figure 7-2.

Aurora Energy's Board of Directors sets the risk appetite for the business. As shown in Figure 7-2, the risk appetite is zero-to-low for risks that have a health, safety and wellbeing or legal/regulatory impact. In contrast, there is a higher appetite for financial risks, given the opportunity for value creation.

When a risk exceeds the Board-approved risk appetite, we consider how best to further reduce the likelihood or impact of a risk event, or both.

Figure 7-2: Aurora Energy risk appetite guide



7.1.2. Roles and responsibilities

Risk management is completed at all levels of our organisation. Our key roles and responsibilities for risk management are outlined in Table 7-1.

Table 7-1: Key roles and responsibilities for risk management

Role	Risk Management Responsibilities
Board of Directors	Establishes the Risk Control and Management Policy, sets the risk appetite, ensures implementation of the policy by the Executive Leadership Team, and monitors mitigation actions where required. This ensures that risk management extends throughout the hierarchy of the organisation, and that the risk appetite for the business is considered when developing and implementing the risk management framework.
Executive Leadership Team	Risk champions for one or more risk themes and accountable for ensuring that they are collaborating across the business to manage risk and maintain effective controls, regularly reviewing and reporting on the status of critical risks and ensuring that risks falling within their risk themes are being actively managed.
Risk Owners (members of our senior management team)	Accountable for ensuring viable risk treatment plans are maintained, overseeing progress of risk treatment plans, and providing regular reporting on the status of their risks.
Control Owners	Accountable for the performance of specific controls – in particular, taking steps to implement or improve controls and to maintain the effectiveness of controls. Control owners are also accountable for monitoring and reviewing controls and providing regular reporting to risk owners.

7.1.3. Risk assessment and treatment

Our process for assessing risks includes identifying risks through a variety of means, analysing the risks using our impact and likelihood criteria, to determine the inherent and residual risk ratings, and considering the application of appropriate controls.

We recognise the need for risk owners and control owners to demonstrate that the controls that are critical to preventing an event or mitigating its impacts are in place and are adequate to manage the risk.

We have developed a control assurance framework that will support control owners to evaluate the effectiveness of their critical controls and have implemented an incident management framework that supports the verification and monitoring of control effectiveness.

7.1.4. Monitoring and review

We are monitoring, reviewing, and managing risk every day. Incidents are triaged and mapped to critical risks for consideration by risk owners and control owners.

Operational risks are monitored by the Executive Leadership Team on a weekly basis, while critical risks that are above the Board-approved risk appetite are reviewed and reported on monthly. Risks that are below the Board-approved risk appetite are reviewed and reported on quarterly by risk champions and risk owners.

The Risk Assurance and Compliance Team ensures the risk control and management framework is embedded within the business. It provides regular reporting on the status of risks, controls, risk treatments, plans and emerging risks to internal leadership groups comprising the ELT and members of the senior management team, as well as the Board, including its Audit and Risk Committee and the Health, Safety and Wellbeing Committee.

The Audit and Risk Committee is responsible for ensuring that an effective risk framework is in place, applied, and maintained.

7.2. OUR BIGGEST RISKS

Our risk themes align to our strategic business objectives and are the overarching groupings for our critical risks.

7.2.1. Health, safety and wellbeing risks

The safety of our staff, contractors, and the public is one of our biggest areas of risk and is reflected in six of our sixteen risk themes. In particular, we are focused on managing the risks associated with our staff, contractors' staff, or members of the public being harmed due to:

- Work being undertaken in the field
- A network access control failure
- Inadequate asset design or condition

Everyone who comes to work at Aurora Energy should go home safe and healthy, both physically and mentally. Our health, safety and wellbeing strategy aims to protect workers from harm and includes activities to foster and support wellbeing. This requires both proactive and reactive interventions. Our framework for managing mental health, 'Wellbeing at Work', is based on the *protect, foster, support, reclaim* model.

Our strategy recognises our role as a Person Conducting a Business or Undertaking (PCBU) as well as our overlapping duties with our FSA partners. We have transitioned to a *trust and verify* model (a collaborative approach to the oversight of partner risk outcomes and performance with shared management of key and emerging risk outcomes). This is reflected in the nature of the controls that we have in place to manage the risks associated with the safety of contractors in the field.

The risks associated with not having the right technology systems to support our risk management processes and not having an appropriate risk management framework in place to support health, safety and wellbeing-related risk management are also critical risks.

7.2.2. Asset risk management

Delivering a safe, reliable, and efficient power supply is our core function. Management of the risks associated with owning and operating an electricity network is integral for our asset-related risk management. Such risks include those associated with inadequate understanding of failure modes and associated safety consequences, as well as condition monitoring and maintenance practices. With a largely legacy asset base built to varying design standards, safety-in-design deficiencies are a real and present risk that must be identified and managed.

Over and above business-as-usual risk management, we consider and plan for potential high-impact low-probability events such as earthquakes, meteorological events amplified due to climate change trends, and wildfires. These are discussed in further detail in Section 7.4.

7.2.3. Works plan delivery

We have committed to a significant works programme throughout our CPP period and we recognise that failure to deliver our operational works plan optimally is a critical risk area for our business. In particular, we must understand our role and responsibilities as an asset management company, as well as those of our partners who are helping us deliver our works programme. We also need to ensure that our partners are capable and competent to deliver the work required and that we have appropriate oversight of their approaches.

Efficient delivery of the programme and fulfilling our commitments to budget and on time are also important considerations, and we are managing the risks associated with not being able to do this.

7.2.4. Technology, information, and cyber risk management

A significant area of risk for us is that our technology does not enable the business, our information is not appropriately safeguarded, and we do not deliver our planned ICT projects to scope, budget or schedule. Further discussion on our ICT management can be found in Chapter 14.

7.2.5. Network operations performance

Our communities and consumers rely on our ability to deliver electricity. One of our biggest risks is that we do not manage energy supply effectively or fail to meet our regulatory performance requirements due to our network operations practices.

7.2.6. Business continuity and emergency response

As a lifeline utility, we are subject to the risk of failing to understand where our key continuity risks lie, take appropriate preventive measures, and ensure that we are ready to respond – all of which are critical to our ability to function during and after an emergency.

7.2.7. Commercial, financial and regulatory risk management

A key strategic objective for Aurora Energy is that of maintaining our licence to operate – in particular, ensuring that we operate within regulatory requirements in a socially and environmentally responsible way and that we deliver value and appropriate return on investment for our shareholder.

This is reflected in the critical risks we have identified, which encompass risks associated with regulatory and legal policy settings and compliance and financial management and reporting.

7.2.8. Our people

Our journey starts with our people. Through a number of programmes and controls, we are actively managing the risk that our people do not have the required capacity or capability to realise our operational and overall strategic priorities. This extends to being able to attract and retain the right people and putting in place succession planning.

7.2.9. Consumers and communities

We remain focused on delivering for consumers and communities. Not understanding the needs of consumers and the community and failing to engage appropriately to maintain goodwill and navigate issues is a risk to achieving this objective.

7.3. USING RISK IN DECISION-MAKING

Aurora Energy has a non-negotiable approach to the risk presented by our assets. Taking a holistic approach, we consider risk in every aspect of asset lifecycle management and have taken the decision to target safety risk as our highest priority.

The safety risk driver is equally paramount for everyone, be they public, staff, or contractor. This said, we draw a distinction between the public and staff, recognising that there are different levels of training, experience, and exposure to the hazards presented by our assets. We also differentiate between assets that are not accessible to the public and those that are.

As part of our pathway toward maturity, we are actively developing the way in which we calculate and express risk. This has taken us from an age-based approach to a more encompassing methodology that now forms an integral part of our lifecycle fleet strategies.

Once the safety risk for our assets is defined, we can apply treatments and mitigations to bring them to an acceptable level.

7.3.1. Network critical risk special cases

We define network critical risks as those involving ‘harm to a member of public or personnel by an asset’. We recognise that the greatest gain for our risk management framework is the reduction of network critical risk.

It must be noted that *criticality* can have two distinct meanings: the network critical risk defined above; and areas of criticality as defined in our GIS.

The groups of assets that present the greatest public safety sensitivity are:

- Support structures
- Overhead conductors
- Overhead switchgear
- Overhead transformers
- Underground cables (exposed parts and terminations)
- Ground mounted switchgear
- Ground mounted transformers

7.3.2. Investment prioritisation

Safety is our foremost priority under the CPP framework, and our approach to risk calculation emphasises direct alignment with our Safety Delivery Plan (SDP), which links expenditure decisions firmly to asset risk profiles. This strategy is pivotal in determining how repex expenditure is allocated, prioritising assets that pose significant safety risks. By evaluating the location and potential impact of these risks, we ensure that our expenditure is targeted where it will be most effective for enhancing public and operational safety.

Expanding our focus, we are now enhancing our existing framework of risk-based decision-making by developing a broader approach that also encompasses reliability risks. Acknowledging the need to balance safety with network performance and sustainability, this development includes a detailed evaluation of network capacity and resilience.

Our asset management and network planning teams collaborate to strategically allocate expenditure, ensuring comprehensive risk assessment for individual assets alongside wider network implications.

The success of our risk-based approach is evaluated by verification of the asset risk levels we forecast in our CPP Safety Delivery Plan.

In addition to evaluating our annual progress against the plan, we assess our network's performance against existing and developing service levels, adjusting our secondary investment drivers accordingly.

7.3.3. Asset health

Asset health reflects the expected remaining service life of an asset and serves as a proxy for its likelihood of failure. From this perspective, age has traditionally been the proxy for health and has thus been the main driver behind our asset replacement and renewal forecasts. However, industry guidelines recognise that asset health is not purely age-based but also involves components of historical usage, cost of ownership, and compliance. To this end, we are now feeding inspection data (see below) into our models, thereby factoring in condition information for more accurate predictions.

Our approach combines condition and age data to modify the base maximum practical life in order to calculate remaining life. This is a proprietary solution developed in-house, which we are calibrating with field data to prove the validity of our model.

Table 7-2 sets out our asset health categories, including their basis and the expected replacement period. It should be noted that when an asset has reached the end of its useful life (H1), it does not mean failure is necessarily imminent. Asset health scores serve as an indicator that an asset requires intervention before it becomes a safety risk, and that further action may be required.

We acknowledge that the categories defined in Table 7-2 are not suited to all asset fleets. For example, a new battery bank with an expected life in the region of 10 years would, given this scale, begin service with an AHI of H3. Current work is underway to align AHI to fleet lives more accurately.

Table 7-2: Asset Health (AH) categories

AH Score	Category Description	Indicated Replacement Period
H1	Asset has reached the end of its useful life	Within one year
H2	Material failure risk, short-term replacement	Between 1 and 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
H4	Normal deterioration, monitor regularly	Between 10 and 20 years
H5	As-new condition, insignificant failure risk	Over 20 years

The assessment of remaining useful life may vary from fleet to fleet. The details are documented in the fleet strategies. Refer to Chapter 11 for the AHI summaries for each fleet.

7.3.4. Asset condition

Asset condition either reflects normal deterioration due to the asset aging processes or points to an excessive impact from external factors. These factors vary from an adverse environment, such as wind or air pollutants, to operational regimes and third-party damage, such as trees fouling assets or vehicle contact. Over the last five years we have made good progress on our plan to include all our fleet assets in our inspection programme. Over time, the improved condition data resulting from the new inspection standards we are developing alongside the implementation of our AMSS will enable us to better understand the nuances of asset condition.

Our scheduled inspection and testing programmes capture a range of condition information across the asset fleets. Where asset condition data is available at a consistent level of detail across a whole fleet, it is fed directly into asset health modelling. Where there is a lack of previous inspection data or the quality of data is questionable, we will default to age-based AHI. Asset condition from inspections provides the basis for short-term renewal and refurbishment decision-making.

7.3.5. Criticality of assets

We apply asset criticality scores (1–5) to indicate an asset's potential to harm the public based on its location and probability of exposure. Using data held in our GIS database, we have developed criticality frameworks across several fleets. This enables us to prioritise expenditure on assets by safety consequence of failure, thus helping us to achieve the safety risk goals outlined in our CPP Safety Delivery Plan. As part of our maturity journey, we are developing a more comprehensive approach that will define criticality of assets by all risk categories.

7.3.6. Asset risk calculation

Asset risk is the primary driver for our network expenditure, particularly regarding asset replacement, where we use this solution to guide the best outcomes for allocating capital to renewal and replacement work.

To calculate network risk, we take fleet data from our company databases and perform quality analysis to ensure the information generated from the data is fit for purpose. Aurora Energy's asset health criteria are then applied to rank the assets in order of health, with the scores then allocated to 'bins'.

This gives us an asset health index for each fleet, enabling us to rank them in order from worst to best. We then apply criticality based on the asset location to give us an asset criticality index. A risk matrix is then generated for each fleet, as shown in Figure 7-3.

Interpreting the matrix is straightforward. Increased likelihood and consequence of asset failure runs from the bottom left-hand corner to the top right-hand corner, which identifies the area of greatest risk.

Figure 7-3: Network risk matrix

Likelihood	Impact: Insignificant	Minor	Moderate	Severe	Catastrophic
Almost certain	Low	Medium	High	Extreme	Extreme
Likely	Low	Low	Medium	High	Extreme
Possible	Low	Low	Medium	High	High
Unlikely	Insignificant	Insignificant	Low	Medium	High
Rare	Insignificant	Insignificant	Low	Medium	Medium

Risk appetite boundary

Our Risk Control and Management Standard defines the impact levels for various risk categories. The yellow line bounding the top right-hand section indicates the boundary at which the risk level becomes intolerable.

Assets assessed as intolerable are then triaged to allow programmed remediation based on their overall risk score. It can be considered that by adopting this approach we are moving from replacement and renewal purely based on age to a more targeted safety (risk) driven methodology.

Projects, works, and actions that reduce the level of a risk across the risk appetite boundary are justified by the requirement to take 'all reasonable practical steps' to reduce risk, while projects that reduce risk outside the 'intolerable risk' area are considered on the basis of cost-benefit analysis. This methodology is broadly consistent with an 'as low as reasonably practicable' (ALARP) approach to risk reduction.

We are committed to further development and implementation of our risk-based decision-making framework. This includes further refinement of the definition of asset functionality, evaluation of the associated risks, and application of effective controls.

We recognise the limitations of our current approach to risk analysis; however, we see that it is fit for purpose given the safety focus of our investment. Alongside delivering the CPP safety-focused plan, we are also driving significant uplift in our asset management practices, which is enabling us to create a robust pathway to fully quantified risk analysis. We know that with high-quality data we will be better positioned to benefit from more sophisticated risk analysis, including investing in technology to support the transition. Some of the key foundational building blocks for this process include:

- Review of inspections and newly-developed inspection standards for all overhead assets, distribution transformers, distribution switchgear, and LV enclosures
- Documentation of fleet strategies, including improvement to our AHI modelling, documentation of failure modes, and assessment and documentation of the likely impact of failure modes against our corporate risk framework
- Institution of a formal process to capture the root cause of asset failures, enabling us to trend and respond to learnings, including understanding new or emerging risks, managing risk through improved design standards, issuing notices or alerts to our FSPs regarding workmanship improvement opportunities, and updating our inspection standards to capture emerging failure modes
- Documentation of our Reliability Strategy, which will subsequently inform our approach to defining a reliability criticality framework

While we have explored the concept of diving into advanced tools to enable more sophisticated and quantifiable risk analysis, our present focus is on ensuring we have quality data and feedback loops, as a priority.

7.4. BUILDING RESILIENCE

7.4.1. Business continuity and emergency response

As a lifeline utility, it is critical to our ability to function during and after an emergency that we understand where our key continuity risks lie, take appropriate preventive measures, and ensure we are ready to respond.

Our current approach is based on the *4R*s of business continuity: *Reduction*, *Readiness*, *Response*, and *Recovery*, as used by emergency services, Civil Defence, emergency management organisations, and other lifeline utility operators in New Zealand. Reduction not only focuses on risk identification, but also includes risk mitigation plans, which may encompass resilience projects. To ensure we are continually improving our business continuity framework, we have added an additional *R*, of *Review*.

We have opted to apply the EEA Resilience Management Maturity Assessment Tool (RMMAT) methodology to assist with gap analysis under the *4R*s approach. The RMMAT consists of 71 specific questions aggregated into 19 functions covering the *4R*s, scored from 0 (not aware) to 4 (excellent).

The application of the RMMAT has revealed that overall, we are in the 'developing' phase, with our main opportunities for improvement being in the 'readiness' phase. While we continue to progress the initial set of improvement initiatives, which focused mainly on business continuity and network operations, we are now also taking steps to address network resilience.

Figure 7-4: Business continuity approach

REDUCTION	READINESS			RESPONSE	RECOVERY		REVIEW
Risk management	Business readiness			Emergency response	Business as usual		Lessons learnt
Business impact assessment	Business continuity plans (BCP)	Recovery plans	Document review and training	Incident management	BCP in action	Return to business as usual	Incident review and continuous improvement

Accordingly, our approach (as depicted in Figure 7-4) has the following five elements:

Reduction: Identify Aurora Energy's critical business functions and analyse the risks to their objectives; take steps to eliminate the risks or reduce the magnitude of their impact and the likelihood of them occurring.

Readiness: Before a business interruption occurs, identify and develop the people, processes, and systems needed to support a response that is proportionate to the severity of the business interruption; ensure Aurora Energy staff know where to find information and are familiar with what to do in the case of a business interruption.

Response: Outline decision points and actions to take immediately before, during, and after an incident that will enable operations to continue, even if at a reduced or minimal level.

Recovery: Outline processes that will enable Aurora Energy to recover as quickly and easily as possible to a business-as-usual state and support medium-term and long-term recovery from an incident.

Test, Maintain, and Review: Develop a schedule to periodically test business continuity plans and resources to ensure they can be relied upon when responding to a business interruption; review all business continuity documentation on a cyclical basis to ensure details are current and remain relevant to Aurora Energy's business objectives.

SUPPORTING A RESPONSE

Our emergency response plans are centred around our identified critical functions and the associated critical resources necessary to deliver those functions, even if at a reduced level. These plans include backup options to ensure we can respond effectively, such as generators for our Network Operations Centres, alternative methods of communication, and options for scaling up resources where needed to support a response. This is an area that we continue to focus on. We take onboard learnings from other responses around the country to ensure we adapt and remain ready to respond. In this year's plan, we have earmarked investment for critical power transformer spares and for spares storage facilities at two locations.

7.4.2. Network resilience planning

Aurora Energy takes a proactive stance toward addressing the resilience of our assets and the wider network amidst the challenges posed by HILP events and the impact of climate change. This understanding is integral to our asset management and strategic planning, guiding a comprehensive approach to enhancing network resilience.

COMPREHENSIVE PREPAREDNESS FOR HILP EVENTS

Understanding the severity and frequency of HILP events is essential for our resilience planning. We are planning to enhance our understanding of natural hazards and climate change impacts to our network to support our resilience-related decision making. We have been involved in the Otago Lifelines project to identify risks relating to potential hazards to lifeline infrastructure across Otago, mitigation strategies, and opportunities to improve critical infrastructure resilience. To aid our resiliency planning, we have also sought additional expert advice on the impact of HILP events on our subtransmission assets.

In our regions, we expect that HILP analysis will identify a need for preparedness for events such as storm/flooding, sea-level rise, earthquakes (including secondary impacts such as landslips, tsunami and liquefaction), and high winds. We also recognise the risk of fire and our role in contributing to the mitigation of this risk. We do this by working with FENZ and putting control measures in place in Fire Prohibited Zones, ahead of the fire season.

ADAPTING TO CLIMATE CHANGE: A STRATEGIC IMPERATIVE

Climate change significantly influences our strategic planning, requiring adaptations to strengthen our network against its various consequences. Our response is guided by the recognition that climate change is a key driver for increased natural hazard risks, and is embedded into our design principles and standards.

- **Flooding and sea-level rise:** The acceleration of sea-level rise and the increased frequency of extreme weather events have sharpened our focus on the resilience of infrastructure in vulnerable locations such as South Dunedin. Taking practical measures, such as asset relocation and reinforcement of critical infrastructure, reflects our commitment to mitigating increased water-related risks.
- **Wildfire risk enhancement:** Regions like Central Otago have a heightened wildfire risk, partly fuelled by climate change. To address this risk, our strategy involves the use of fire-retardant materials, strategic redesign of network layouts to minimise fire hazards, and implementation of advanced detection systems for early warning and rapid response.
- **Wind intensity escalation:** Increasing wind intensity, particularly in areas prone to severe wind conditions, prompts us to reinforce our infrastructure's structural integrity. We supplement this effort with sophisticated monitoring systems for effective mitigation strategies.

STRATEGIC ENHANCEMENTS AND CONCEPTUAL CONSIDERATIONS

We are addressing immediate challenges and proactively considering future expenditure to improve network resilience. With an additional funding provision of $20 million over the planning period for areas such as critical spares, our strategy encompasses both actions undertaken and future exploratory work, including:

- **Asset upgrades and relocations:** We have some initiatives in place and will continue to develop thorough plans to safeguard essential infrastructure against possible seismic impact and the risks posed by flooding.
- **Accelerated asset replacement:** This approach reflects our commitment to replacing assets in high-risk areas as a pre-emptive measure for the increased risks associated with climate change.
- **Future explorations:** We are positioned to conduct comprehensive analysis of climate trends such as wind speed, temperature fluctuations, and the impact of major earthquakes on underground infrastructure. These studies are critical to refining our resilience strategy and design standards, reflecting the extensive work ahead.

In navigating resilience planning, Aurora Energy takes a measured approach, balancing the tangible steps already taken with the conceptual exploration of future pathways. Our commitment to enhancing network resilience stems from a strategic, informed, and community-engaged response to the challenges posed by climate change and natural hazards. This journey involves ongoing expenditure, innovation, and a realistic acknowledgment of the work that remains. Through this approach, we aim to safeguard our infrastructure against current challenges and future-proof our network against evolving risks.

7.5. RELIABILITY MANAGEMENT

Reliability management involves maintaining our network to the appropriate levels of service required by our consumers. As consumers move away from traditional sources of energy, we are aware of the increasing reliance on electricity in our region's future. We endeavour to deliver a level of reliability that meets the needs and expectations of our customers, but we must attempt to balance any improvements with associated costs. As such, we seek to optimise the life of our assets by building our asset management maturity such that we can drive informed, evidence-based investment decisions that enable us to manage risk while getting the most value from our assets.

Understanding the health of our assets, how they fail, and why they fail all helps inform our decisions about where to target our investment. However, we also experience asset failures or faults as a result of external factors including vegetation contact and strikes, severe weather events, wildlife interference, and third-party damage such as vehicle strikes or digging leading to cable strikes.

We track and monitor faults by cause, and endeavour through root cause analysis to learn and improve our controls with respect to faults arising from these external factors.

In some cases, we look to network configuration for solutions to reduce the impact in terms of the number of customers impacted by any one failure event.

As we improve our network, we also try to reduce the impact on consumers from planned shutdowns, and we ensure consumers are well notified in advance via their retailers and our website.

7.5.1. Reliability improvement strategy

Reliability improvement is largely driven by improving our internal processes, from sourcing and analysing data about faults and our network to identifying the most appropriate solutions when an issue emerges.

Our investment strategy for reliability focuses on two key drivers for change:

- Reducing the frequency of faults on our network
- Reducing the impact on consumers when a fault occurs

From the perspective of reducing the frequency of faults, we are developing plans to address the most common causes of network faults, as outlined in Table 7-3.

Table 7-3: Plans to address common faults

Outage Cause	Plans to Improve Performance
Equipment deterioration	We actively review all asset failure events on our network to better understand root causes. We use this information to identify immediate improvement actions and revise our ongoing asset inspection, maintenance, and renewal programmes. Since undertaking this improvement action, we have identified several asset failure trends that have influenced our approach to managing specific asset types (see **Section 11.2**).
Vegetation	We currently survey our network on a three-year cycle to identify vegetation growing near overhead lines. Based on the current Tree Regulations, we issue notices to tree owners when vegetation encroaches within a set distance from our lines. While we have seen an improvement in the frequency of tree-related outages in recent years, we are still often exposed to trees and branches outside the regulated distances falling through our lines, particularly during severe weather events. We are investigating a risk-based approach to managing vegetation outside the regulated distances, with the aim of achieving the optimum balance between additional cost and potential reliability improvement. In 2024, MBIE published a set of revisions to the existing Tree Regulations which, in some cases, increases the growth corridors for vegetation near overhead lines. MBIE have also undertaken a review and consultation process relating to management of vegetation outside the regulated distances. Further updates are expected in 2025. (See the discussion of our vegetation management programme in **Section 11.2.4**.)
Third-party events	Vehicle crashes and digging into underground cables are common causes of unplanned outages. We have limited control over these third-party events, but we do engage with contractors to ensure that they comply with all health and safety requirements when working around our cables. In the future we may also consider changes to our network (such as undergrounding or relocating poles) in crash-prone areas.
Unknown causes	Outages are classed under 'unknown cause' when our crews have inspected a fault site and are unable to identify a definite cause. In many cases, these outages are caused by external factors that are not apparent when fault crews reach the site. Examples include contact with trees or flying debris during strong winds, as well as bird clash or nesting animals. In other cases, there are minor defects in our assets that are impossible to detect during visual inspections. Currently, we conduct further investigation when a circuit experiences multiple unknown outages within a short-term period – which generally suggests there is a persistent issue. We apply a root cause analysis approach, which may include advanced inspections, to enable us to efficiently identify and address the cause.

In addition to reducing the number of unplanned outages across our network, we also aim to deliver benefits by improving the way our network and our fault staff respond to outage events, as outlined in Table 7-4.

Table 7-4: Reliability improvement initiatives

Reliability Initiative	Plans to Improve Performance
Improve fault restoration times	We have developed fault response target times, which came into effect from 1 April 2024. Ongoing performance is tracked against these targets, and we require follow-up investigations and reports where performance does not meet our expectations. Fault indicators are devices that can be installed on the network to guide crews on where to look for a fault. Smart indicators have the added functionality of sending fault information to our operations centre so that we can send crews directly to a fault location. We have set aside a budget to increase the number of fault indicators on our network over the coming years. We expect this investment to deliver faster restoration times for consumers, particularly in large remote areas of the network.
Reduce customers affected per fault	The number of customers affected by an outage depends on the circuit and the location of the fault. In some cases, we can invest in additional switching devices on a circuit to reduce the number of customers affected when a fault occurs. We installed recloser devices on two of our worst-performing feeders in 2023 and have budgeted for additional projects in the coming years.

7.5.2. Reliability-focused investment

In our organisational risk control and management framework, reliability risk is assessed based on the degree of impact on consumers. Generally, our zone substations and subtransmission circuits present the greatest risk to reliability performance. Our approach to reliability risk is guided by our security of supply guidelines (see Section 10.1.2), which set design requirements for these core network assets.

Our investment approach is driven by reliability risk within the following areas:

- **Zone substation renewals:** When assessing the realistic impact of failure for all zone substation assets, we consider the potential loss of supply to consumers, plus any potential alternative supply options (see Section 11.6).
- **Growth and security investment:** We identify investment needs for zone substations and subtransmission circuits based on existing and future security needs. In areas of significant growth, we have identified greater reliability risk in the event of asset failure. In such cases, we have outlined plans for future expenditure (see the discussion of growth and security investment in Section 9.1.1).
- **Vegetation management:** Ongoing inspection and maintenance cycles are required to manage vegetation on an ongoing basis. Rather than the three-year cycle applied to standard circuits, critical circuits are prioritised on a 12-month inspection cycle (see Section 11.2.4).
- **Asset inspection trials:** When trialling new technologies to improve detection of asset defects, we prioritise subtransmission circuits due to the increased reliability risk.

We understand the need to spend wisely to ensure we strike the right balance for consumers between increased reliability and increased electricity costs. Over the planning period we aim to refine our strategy for managing reliability.

We are capturing more information about fault events with the aim of using machine learning and AI tools to help us better understand the factors that drive our reliability performance and identify actions we can take to address them. We are also developing network models to help us identify potential changes to our network that would reduce the impact of faults on consumers by decreasing the number of customers affected or by helping restore parts of the network faster.

We have established a dedicated budget for reliability initiatives over the planning period, with increased focus in the years beyond the CPP period. We have not dedicated this additional expenditure to specific projects, but have allowed for some flexibility to address reliability issues as they emerge.

Table 7-5: Reliability investment over the planning period (RY25 constant, $m)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Reliability investment	0.3	0.6	0.6	0.6	1.5	1.5	1.5	1.5	1.5	1.5

In addition to direct expenditure on our network, we are also looking to improve reliability by developing our internal processes and analytical capability. Our overall goal is to establish performance expectations for all our customers, to continually monitor performance so that we can identify issues when they emerge, and to identify the most effective solutions to restore performance to normal levels.

Table 7-6: Reliability improvement goals

Improvement Goal	Plans to Improve Performance
Establish performance targets	• Refine performance targets at a circuit level, with the aim of setting targets for individual customers. Develop targets by considering consumer expectations as well as current limitations in network topology. • Refine targets based on our understanding around external factors that can affect performance in localised areas. We plan to develop network zones to account for differences between regions regarding things like extreme weather, vegetation growth, flood risk, wildlife, and vehicle crashes. • We anticipate the need for ongoing review of performance targets to accommodate network growth and the changing needs of consumers.
Monitor fault performance	• We currently track outages at a circuit level so that we can identify how individual circuits perform against target. • Within our ADMS (Advanced Distribution Management System), we record a list of customers affected by every outage. As we introduce performance targets at a consumer level, we can better utilise this customer outage history to monitor performance. • In addition to customer-based targets, we also plan to monitor how individual circuits and asset types perform against established failure rates. This information helps us track issues that might be related to a specific area or a specific equipment type.
Identify optimal investment solutions	• We perform root cause analysis on all equipment failures to identify appropriate preventive solutions. Over time we plan to expand this approach to all network faults. • More detailed data capture for all faults helps us make informed decisions when we need to address performance issues in a specific area. Where we can identify common factors, it helps us drill down the most practical solution. • In future, we aim to develop a structured approach to managing reliability performance issues. For all cases where a circuit exceeds a performance target, we can identify a short list of potential solutions based on the nature of the problem. From there, we can implement the most cost-effective solution or range of solutions.
Continual improvement	• As we develop a larger and more thorough fault database, we can utilise the information to refine our understanding around how and why assets fail, and to apply preventive solutions to avoid unnecessary outages. • Once we have applied solutions in poor performing areas, we will undertake further monitoring to assess the long-term effectiveness of the chosen solution. Over time, we can refine our list of solutions to favour those that have a proven track record. • We will look to explore new technologies to expand our list of potential investment solutions. We will also work with industry partners to identify any shared learnings.

CHAPTER 8

MANAGING INVESTMENT UNCERTAINTY

While we do our best to provide evidence-based network development plans, the future can be hard to predict. So we have outlined the key areas of uncertainty that may impact future expenditure.

Much like its predecessor, AMP25 finds us navigating a complex landscape characterised by various input drivers, each presenting a unique level of forecast uncertainty. The need to manage and stay just ahead of changing demands across a diverse landscape creates a level of uncertainty that is unavoidable.

Managing the extent of climate change (which is driving more diverse uses of electricity and thus demand) is a global effort; and equally, a global challenge. In addition to a significant level of uncertainty around the speed of change and electrification, there are factors that compound the uncertainty around emerging technologies for capturing or eliminating the creation of carbon and for reducing the impact of climate change on our network. In addition, the emergence of new digital technologies creates new opportunities and community expectations to lift our asset management capability and services. The pace of change continues to accelerate and therefore many of the drivers informing our capital and operational expenditure forecasts are dynamic. Our AMP forecasts represent the best information available to us at the time of planning. Our annual review process provides us with an opportunity to flex our plan as required, should new information come to light.

8.1. FORECASTING CONSUMER PRIORITIES

As we deal with the uncertainties highlighted in this chapter, our expenditure planning approach goes beyond reacting to change. As such, we are actively shaping our network to meet future consumer needs and expectations, while keeping our planning flexible and forward-looking. This section highlights how we consider consumer priorities in our strategic responses to uncertainty and the challenges of making precise forecasts.

As outlined in Chapter 2, our priority investment drivers form the rationale behind our planning and forecasting. In particular, the issue of 'Changing Consumer Expectations' presents a challenge. We are not yet fully equipped to predict how consumer preferences will evolve. The challenge lies in understanding how consumers will interact with and impact our network as they adopt future technologies such as electric transportation and DER. The degree to which these technologies are adopted and valued varies between consumers across our network, and this variability represents an ongoing challenge.

Another priority investment driver is asset safety. As our maturing asset management practices enhance our understanding of how to optimise our safety driven investment, there remains some uncertainty with respect to the level of investment required, including uncertainty around the future development of populated areas and the safety implications of the changing environment.

Managing consumer expectations in this uncertain landscape is key. We are committed to ongoing discussions with consumers to grasp their changing needs and preferences, as discussed in Chapter 4. This ensures our planning and expenditure strategies stay aligned with consumer expectations despite the forecasting challenges. We also acknowledge the limitations of our current forecasting capabilities in terms of being able to fully capture potential shifts in consumer behaviour and preferences.

8.2. AREAS OF INVESTMENT UNCERTAINTY

The complexities of investment forecast uncertainty manifest through several critical dimensions.

8.2.1. Asset Renewals

While the necessity of asset renewals is well understood, determining precise expenditure remains a flexible endeavour. Our goal with respect to renewals is to optimise the life of all assets, while managing risk and striving to meet the service level expectations of our communities. We are also working toward minimising the planned interruptions resulting from our renewal programme. The challenge is complex, but we are building solid foundations in our approach to asset management that are enabling us to make evidence-based decisions around trade-offs between cost, risk, and level of service. Our continued journey to asset management maturity is essential to enable us to provide the best service possible at the least cost to consumers. As our asset management approach matures and we gain confidence in our ability to make the decisions required to meet our objectives, we will flex our plan to take account of advancements.

8.2.2. System Growth

Forecasting demand at this time of significant transition inherently presents challenges and uncertainty. It is prudent that we continue to refine and re-forecast our best views, with input from key stakeholders, on a continuous basis. This ultimately drives a need to continually challenge and flex how we define, prioritise, and re-prioritise our plan. The pace and impact of electrification, the timing of large commercial and industrial developments (load and generation), and changing customer energy needs are the greatest areas of uncertainty in growth expenditure.

8.2.3. Decarbonisation and DER

The pace of the uptake of distributed energy resources, process heat and transport electrification, coupled with potential changes in regulations, poses a significant level of expenditure of uncertainty. The transition to light electric vehicles coupled with solar power adoption rates will influence spending on our low-voltage networks.

8.2.4. Reliability

We believe that maturing asset management practices – including an increased understanding of how our assets perform and fail – are enabling us to take a targeted and evidence-based approach to investment. By making sure we properly understand the problems, we can tailor our solutions and subsequently optimise our investment and the lives of our assets. We acknowledge that there are localised areas of our network where consumers experience reliability that may not meet their expectations. We are actively working to understand and manage these 'hotspots' and will refine our expenditure levels to meet emerging needs. This also entails exploring potential solutions based on enhanced network configurations, remote switching, and automation to align with consumer reliability expectations. Again, we will flex our plan as our approach to reliability matures, and in response to the performance of our network. Concurrently we are working on developing our overall network reliability strategy, which will inform our approach to investment in reliability as we transition from CPP safety-focused investment into DPP4.

8.2.5. Resilience

As a lifeline utility service, we recognise our role in resiliency and readiness to respond to adverse events. However, the costs associated with strengthening our infrastructure and with preparedness are unknown. This uncertainty extends to the potential impact on network configuration and equipment standards. This is not unique to Aurora Energy; the need to strengthen the resilience of critical infrastructure in New Zealand is the subject of a Department of Prime Minister and Cabinet (DPMC) consultation paper 'Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system'. The outcomes, including potential for reform are unknown. To acknowledge the need to begin building resilience, our capex forecast (refer to Chapter 15) reflects a proposed $20 million expenditure over the AMP period. Since our last AMP, we have identified and incorporated expenditure for two spare power transformers and also allocated budget to secure two spares storage facilities. The HILP analysis will contribute significantly to the next steps, in terms of defining specific spares requirements.

8.2.6. Digital Transformation

While the development of certain aspects such as core asset management software solutions and advanced distribution management systems (ADMS) is assured, expenditure on low-voltage (LV) visibility has been incurred at very modest levels in previous years. Access to smart meter data will be an enabler to progressing this.

8.2.7. Vegetation

Management of vegetation remains critical for preventing unplanned outages. We have adjusted expenditure to reflect recent amendments to the Tree Regulations; however, final outcomes pertaining to the treatment of hazard trees (which includes fall zone trees) remains uncertain. Further regulatory obligations related to hazard trees would increase our vegetation management costs. Additional to that, we are actively tracking the cause of our vegetation faults to ensure we are, to the best of our ability (not always within our control), investing in management of vegetation that causes the greatest risk, as a priority.

8.2.8. Consumer service lines

During the CPP period, we committed to undertaking a review to ensure consumer line asset ownership was clear as to the responsibility for maintenance and renewal of these assets. As part of this initiative, we have undertaken to carry out a one-off inspection and critical maintenance of these assets, before notification of rightful ownership. This programme is underway, including inspection, maintenance or renewal, and notification of ownership. Because this programme involves inspecting assets on private land where Aurora Energy may not have all the relevant records, it attracts a high level of uncertainty. We have deployed a number of approaches to ensure we take all reasonable steps to proactively identify and manage these assets, updating our forecasts as more information becomes available to us through the inspection process.

All of the above leads to a level of uncertainty in any given forecast. An essential part of our annual AMP review is understanding and making informed and prioritised investment decisions with regard to the creation of an overall optimised expenditure plan.

8.3. DEMAND GROWTH IN THE UPPER CLUTHA REGION

Systems growth is considered in the context of our year-to-year review of the AMP period plan and need for prioritisation. We are currently in a position of having a foreseeable but significant investment need that still has associated levels of uncertainty around the solution, the cost, and the timing.

The Upper Clutha region takes 80% of the load from Cromwell GXP. As outlined in Section 10.6.3, the demand from Cromwell GXP is growing at a rate that is signalling a need for significant investment during this AMP period.

In the last 10 years, demand has grown by 20 MW. In 2024, demand peaked at 5 MW more than 2023, and in the last four years it has grown by 7 MW – an annual average increase of 2 MW. Our demand forecasts indicate that this will continue beyond this planning period.

To ensure our investment and determined solutions consider a longer-term view, this year we have worked with Transpower, Queenstown Lake District Council and other key stakeholders to collate a best view of forecast demand out to 2050. The forecast drivers include known 'point loads' (significantly high local loads), transport electrification, process heat conversion, population growth, economic activity, DG penetration (EV, solar, solar-battery), as well as seasonal variations in climate and in population due to tourists. Although, this is the best view available to us, there is a level of uncertainty regarding the long-term forecast.

Our AMP25 forecast for this project has changed significantly since AMP24, up from $40.7m to $65.4m in AMP25. In AMP24, we allowed for a short-term solution with additional solutions beyond the 10-year AMP period, but we no longer believe this approach is appropriate.

With the above-mentioned long-term electricity demand forecast, Transpower has created a long list of options with respect to GXP and transmission solutions. Aurora Energy has created a list of options to inform the minimum viable sub transmission and distribution network solution to distribute electricity from the GXP to consumers.

Our objective is to ensure a reliable and sustainable energy future taking into account the impact on consumers. At the time of writing this AMP, our current and best view is that we will be able to stage the overall upgrade of the network such that we will phase the development of the Upper Clutha network over five years from RY27 to RY31. More details on the forecasting assumptions and options are outlined in Chapter 10.

This project is currently forecast to be required by RY31, at a cost of $65m (RY25 Constant dollars). The five-year plan has a level of investment uncertainty regarding cost, variation of solution, and timing.

8.4. MANAGING INVESTMENT UNCERTAINTY THROUGH PRIORITISATION

From the perspectives of enabling the growth of our network to service new customers and increasing the capacity of our network to service electrification of heat and transport, and within the context of growing costs, we continue to review and re-prioritise our plan.

By maturing our asset management practices, we are better able to make informed risk-based decisions around how or what to re-prioritise. Each year, we use the most up-to-date information available to us to re-prioritise our plans to optimise delivery of our priority outcomes:

- Ensuring we are managing safety risk on our network
- Meeting the growing demands of existing customers while continuing to connect new customers
- Maintaining security of supply and quality of supply commitments

While the upward pressures of unprecedented growth and unforeseeable inflation have significantly impacted our ability to deliver the quantities of renewals predicted to be required at the time of our CPP application, we have largely managed to maintain progress against the outcomes we were striving for in our safety-focused CPP.[3]

We have done this by significantly enhancing our asset management practices: predominantly, our understanding of asset condition and the precursors to failure. Our enhanced condition-based approach to high volume fleets such as crossarms has enabled us to confidently signal a significant reduction in investment needed. However, because we have focused the renewal programme on achieving safety outcomes, we have not delivered renewal levels signalled for non-public-safety sensitive fleets. AMP25 continues in this vein.

While several programmes that have nil to low public safety impact have been deferred, one fleet that is not meeting SDP targets has been set a stretch goal for the DPP4 period.

With low historic levels of renewals for protection assets and subsequent impacts due to timing and re-prioritisation of associated zone substation work over recent years, we are not on track to meet our plan with respect to reducing %H1 assets within the CPP period. We have set a target of catching up on this renewal backlog within the DPP4 period.

We acknowledge our role in ensuring that our investment plan is affordable and sustainable. Each year, we produce a plan that is informed by our best view of how to meet our priorities, using all available information. This means our plan will continue to flex to best serve consumers.

8.5. AMP25 PRIORITISATION

In developing the investment profile for AMP25, we used the priorities outlined above to determine the investment level requirements.

By leveraging improved data, we used a shift from age-based to condition-based renewals to inform renewals for our crossarm fleet. Based on data received to date (approximately 20% of the overhead network has been inspected under our improved inspection programme), we extrapolated to assess the likely renewal requirements for the fleet. We will review and refine our assumptions as the complete data set becomes available, but we consider the results indicated by this process sufficient to reduce the investment requirements previously indicated for this fleet.

As a result, the quantity of crossarms indicated as being at end of life has reduced from 5589 (approximately $23.5m) in AMP24 to 4563 (approximately $21.7m) in AMP25. We have also signalled deferrals of the volumes previously indicated for the following renewals:

[3] For more detail, see **Chapter 11** of this AMP. Specific metrics regarding the SDP are provided in Chapter 4 of our latest Annual Delivery Report (available on the Aurora Energy website, at https://www.auroraenergy.co.nz/disclosures).

- LV cables from 15 km (approximately $8.2m) in AMP24 to 12.3 km (approximately $7.8m) in AMP25
- Distribution cables from 30 km (approximately $16.4m) in AMP24 to 27.7 km (approximately $15.8m) in AMP25
- LV conductor from 179 km (approximately $29m) in AMP24 to 134 km (approximately $16.5m) in AMP25

This is informed by the impact of failure and our current ability to make evidence-based investment decisions in these fleets.

8.6. EXCLUDED EXPENDITURE

The expenditure forecasts included in this AMP exclude major projects that we do not consider it reasonable to include in the expenditure at this stage. These are listed in Table 8-1. If these projects are included in future forecasts, we intend to apply to the Commerce Commission under a reopener process. This list represents our latest view, which may change year-on-year as new information comes to light.

Table 8-1: Major projects excluded from expenditure forecasts

Excluded major projects	2025 AMP High level cost estimate ($m)	Why we're not committing to the investment in this AMP
New Bendigo Customer	0	Commercial arrangements for this new connection have yet to be agreed with the customer. Our current assumption is that the customer will fully fund the new connection.
Parkburn zone substation and Distribution Network	10.0	We are aware of early stage proposed residential subdivisions and commercial developments in the Mount Pisa area which have not reached sufficient certainty to justify including the investment in our plan. If the proposed developments are realised, the network will see a significant load increase exceeding the capacity of the existing single feeder from Cromwell.
Alexandra-Omakau Subtransmission Stage 1	3.4	The demand on the single subtransmission circuit, predominantly irrigation, has remained stable over the past six years. However, the addition of a 1 MVA load will exceed its thermal capacity. As it remains uncertain how this additional load might occur, we have not included this investment in the plan. We will continue to monitor the load and any new load applications to inform this investment.
Camphill 66 kV Power Transformer	5.8	The forecast for the N-security Camp Hill zone substation indicates a continued increase in demand, necessitating an upgrade to the security level to comply with our Security of Supply guidelines. However, due to uncertainties around the projected growth, we have excluded this investment from the current plan.
Riverbank Second Transformer and 11 kV feeder Stage 2	7.0	Forecasts indicate a sustained increase in load on the N security Riverbank zone substation. This potential demand growth was not included in our current plan due to uncertainty. If this growth materialises, an upgrade to an N-1 security level will be necessary to comply with our Security of Supply Guidelines.
New Queenstown 33 kV supply	7.6	Demand forecasts indicate that the peak demand of the N-1 Queenstown 33 kV subtransmission circuits will continue to grow, surpassing the circuit's firm capacity from the medium term onwards. However, because we lack certainty that this load growth will continue, we have excluded this investment from the plan.
Gibbston Substation	9.5	We understand that there are proposed residential subdivisions in the Gibbston area, which is currently serviced by a single distribution feeder with small conductors. However, we have not included the construction of a new zone substation in the plan as we do not know the load requirement and timing of these subdivision developments.
Stevenson Rd Supply	4.5	We are aware of a significant development that would necessitate a substantial increase in load which in turn would necessitate a new feeder. However, the timing is currently uncertain and, as such, the investment provision has not been included in the current plan.
New Whakatipu zone substation	7.0	The prudent demand forecast for the Frankton zone substation suggests a need for the establishment of a new zone substation. However, due to uncertainty regarding the magnitude and timing of this growth, we have not included this investment in our current plan.
Total	**54.8**	

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OUR FUTURE NETWORK

CHAPTER 9
DRIVERS FOR CHANGE

The landscape of the power system is changing, with increasing electrification driven by decarbonisation and consumers adopting new technologies enabling generation. The climate and the environment are changing. We must develop our network to meet the changing future and electricity demands with network and non-network solutions.

9.1. NETWORK DEVELOPMENT DRIVERS

As outlined in Chapter 2 and Chapter 5, we have identified priority investment drivers, which are linked back to our five Strategic Focus Areas and inform our network development expenditure.

We use a risk-based network development approach to inform the need to invest. By assessing safety, security, capacity, reliability, environment, customer satisfaction and other risk categories, we are able to establish relative criticality in order to prioritise solutions. We consider how the network will perform and operate under various scenarios of risk development, as well as the impact of decarbonisation for sustainable long-term investment. Demand growth, technology, climate, and regulations contribute to the development of these scenarios.

The need for network development expenditure is driven by a number of factors, including:

- **System demand:** The peak demand for power and energy at GXP, zone substation and 11 kV distribution feeder levels, compared to the capability of our network
- **Security of supply:** Our ability to meet defined supply security guidelines
- **Power quality:** Our ability to meet regulatory and industry standards regarding power quality

9.1.1. Growth & security investment

Planned expenditure on growth and security is developed on the basis of a minimum viable plan to meet known capacity and security of supply gaps. We have developed three growth scenarios based on our decarbonisation study (*Sustainable*, *Chaotic*, and *Alternative Energy*; see Section 9.4.1).

Our forecasts based on the Sustainable scenario assume we have the ability to shape the demand profile to enable a high level of network utilisation. This scenario relies on cost-reflective pricing and other flexibility service arrangements to prevent the development of new peaks – for example, to prevent herding at the start of the 9pm night rate period.

Although we have based our planned expenditure on the Sustainable scenario, other traditional drivers for spending such as shortfalls in capacity to connect new customers and security of supply gaps remain relevant, but at an accelerated rate with strong growth.

We have also developed an investment plan to accommodate major projects where there is uncertainty around the need case or the timing of the upgrade project. This expenditure will be triggered once the uncertainty is removed and we apply the Commerce Commission's reopener mechanism.

We classify our growth and security expenditure into the following types of projects:

- **Major Projects:** Apply to zone substations, subtransmission, or GXP-related works. Major projects are forecast on an individual, project-by-project basis.
- **Distribution and LV reinforcement projects:** Distribution reinforcement allows us to add capacity to existing parts of the feeder network, create additional feeders or backfeed ties, upgrade from 6.6 kV to 11 kV, and install or upgrade voltage regulators.[4] LV reinforcement is a relatively reactive process, reflecting the lower value and higher volume of assets (compared to the distribution level). The addition of new load is managed through our customer connection process.[5] With the uptake of PVs and EVs gathering momentum (clustering in some cases) and electrification of other fuel uses in households, we expect an increasing need to invest in additional capacity in some LV networks. We discuss the LV investment forecast in Section 9.5.1.

9.1.2. Consumer connections

Consumer connection capex is expenditure to facilitate the connection of new consumers to our network. On average, we connect around 1,250 homes and businesses to our network every year.

New connections range from a single new house through to a range of businesses and infrastructure. The latter may involve small connections like water pumps and telecommunications cabinets, or large connections where the network upgrade is directly related to the connection site. Although a new connection may drive the need for upstream upgrades to the distribution or subtransmission network, the cost of this work is outside the scope of this portfolio.

FORECASTING APPROACH

Expenditure on consumer connections is largely driven by:

- **Population growth:** The number of new residential properties is driven by population growth, land supply, and government policy (for example, special housing areas). These impact both small connection requests and large subdivision developments.
- **Economic activity:** Growth in commercial activity increases the number of commercial and industrial premises that require electricity supply.

APPROACH TO EXPENDITURE FORECASTING

Consumer connection capex is externally driven with short lead times. It is difficult to accurately forecast medium-term customer connection capex requirements. We have adopted a base-step approach to forecasting consumer connection capex, which involves:

- **Base:** We have established a base level of consumer connection capex by averaging the spend over the past five years and normalising for large one-off projects.
- **Step:** We have identified a step change in consumer connection capex related to electrification projects such as boiler conversions and EV charging stations. This step change has been quantified based on large known projects that have been forecast to occur within the next two years.

Historically, we have seen significant year-on-year variation in both consumer connection capex and capital contributions. In developing our forecast, we considered the following inputs and made the following assumptions:

- Average historical customer connection volumes are a reasonable predictor of future volumes, provided population GDP growth remains broadly in line with historical growth.
- Assumptions around large customer projects, including timing and cost, reflect our current best estimates and discussions with consumers.
- No contingencies have been included.

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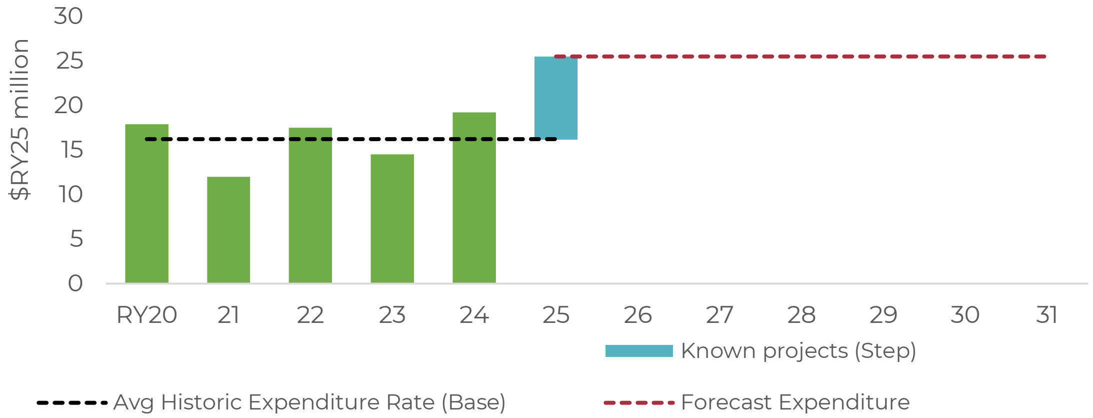
[4] Occasionally, the upgrade of a distribution transformer will occur as part of the above works; but more generally, such work is delivered as part of our customer connections work, which is described in **Section 4.4**.

[5] Note that LV reinforcement is concerned with the LV network impacts of new customer connections, rather than the actual connections. Investments for the consumer connections themselves are discussed in **Section 4.4**.

Figure 9-1: Expenditure forecasting for consumer connections



CAPITAL CONTRIBUTIONS

Our Capital Contributions Policy published on 1 July 2021 results in an average consumer contribution of 60% for new and upgraded connections.

We anticipate a refresh of our Capital Contributions policy will be required in 2025, following the Electricity Authority's review of connection pricing. We do not expect the refresh of our Capital Contributions policy to change the level of reliance on consumer contributions.

POWER QUALITY

Power quality relates to the voltage delivered to the customer's point of supply for the specified load. It covers voltage magnitude, distortion, and interference of the waveform. Targets for voltage levels are specified in Part 3 of the Electricity (Safety) Regulations 2010 and industry standards. We aim to provide a regulatorily compliant quality of supply to all consumers at all times. We do this through effective planning and good network design.

Power quality is generally managed by ensuring adequate network capacity. Undersized reticulation or high impedance transformers (where they are necessary to manage fault levels) increase the risk of power quality issues. Some projects involve the connection of equipment (for example, variable speed drives) that can create high levels of harmonic distortion, potentially necessitating the installation of harmonic filtering equipment to reduce distortion to acceptable levels.

At this stage, work to address power quality issues is reactive, whereby we respond to consumer complaints. We have created a reporting tool for consumer complaints, which enables us to review our performance based on set targets for analysis time, response time, and resolution time (see **Section 5.1.3** and **Table 5-6**).

We are using distribution transformer monitoring (DTM) devices to provide real-time data and alarms to engineers' desktops. We have installed 64 of these units at strategic locations to provide baseline power quality information about the network, with the aim of having a total of 72 installed by the end of RY27. We also install power quality meters to verify whether consumer complaints relate to network issues or customer-side issues.

With the level of solar penetration in our network at this stage, we have not experienced any power quality issues relating to solar; however, if PV uptake is left unmanaged, issues will arise. In the future, power quality issues will be monitored using an LV Visibility platform leveraging smart meter data.

VOLTAGE MAGNITUDE

Regulations require the standard low voltage (nominally 230V) to be maintained within ±6% at the point of supply except for momentary fluctuations. The proposed regulation change to increase the upper limit to +10% increases the capacity of the network to connect more DERs, allows increased DER export, and defers or avoids LV investment to mitigate constraints.

HARMONICS: DISTORTION AND INTERFERENCE

Harmonic voltages and currents in an electric power system typically result from non-linear electric loads. Non-linear loads include those from variable speed drives, switch mode power supplies, electronic ballasts for fluorescent lamps, and welders injecting harmonic currents into the network. These harmonic currents couple with the system impedances to create voltage distortion at various points on the network and can cause malfunction or complete failure of equipment such as computers, digital clocks, transformers, motors, cables, capacitors, and electronic controls that are connected at the same point.

We use the limits indicated in Table 9-1 to gauge harmonic voltage distortion lasting longer than one hour. For shorter periods, during start-up or unusual conditions, these limits may be exceeded by 50%.

Table 9-1: Maximum voltage distortion limits in % of nominal fundamental frequency voltage

Individual voltage distortion (%)	Total voltage distortion THDv (%)
3.0	5.0

9.2. PRIORITISING NETWORK DEVELOPMENT PROJECTS

Prioritisation of network development projects is a relatively complex process. In addition to economic benefit and the severity of the need, we consider the following factors when prioritising across a set of network development projects:

- **Coordination with other works:** We aim to prioritise projects within the context of our wider asset management activities (e.g. renewal plans, ongoing projects, consumer connection) to optimise expenditure across all business objectives. We may adjust the timing of expenditure to enable the work to be integrated with related projects.
- **Consumer expectations:** We prioritise the constraints most likely to impact consumer service through prolonged or frequent outages or compromised power quality (voltage drop).
- **Compliance:** We aim to maintain compliance with all relevant legislative, regulatory and industry standards, prioritising projects that address compliance gaps.
- **Contractor resourcing constraints (deliverability):** We aim to schedule work to maintain a steady workflow to our FSA partners. This reduces the risk of them being either over- or under-resourced.
- **Coordination with local authorities:** We aim to schedule our projects to coincide with major civil infrastructure projects undertaken by local authorities. The most common activity of this type is coordination of planned cable works with road widening or resealing programmes to avoid the need to excavate and then reinstate newly laid road.

After assessing the relative priorities of each proposed project, we rely upon the knowledge, experience, and professional judgement of our asset management team to make the final decision regarding the exact timing of an individual project within the 10-year planning window.

When the project selection process is repeated, all projects (including new additions) are reviewed. They may be advanced, deferred, modified, or maintained in the planning schedule; or they may be removed from the programme. Projects that are not included in the plan for the next year but which we believe need to proceed during the planning period are provisionally assigned to a future year in the 10-year planning window.

9.3. NETWORK EFFICIENCY

Our network efficiency measures focus on the following factors:

- Load factor at GXPs
- Loss ratio
- Total transformer capacity utilisation

9.3.1. Load factor at GXPs

Load factor at GXPs is the ratio of the total energy during an interval (in this case one regulatory year) over the product of the peak demand and the total hours of that interval. It measures the efficiency of assets we contract from Transpower at GXPs. A lower value indicates excess capacity and cost, while a higher value can also cause concern due to insufficient capacity.

Table 9-2: Load factor

Load Factor (%)	Historical			Forecast (%)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Dunedin	48	50	51	50	50	50	50	50	50	50	50	50	50
Central Otago/Wānaka	55	58	59	57	57	57	57	57	57	57	57	57	57
Queenstown	44	49	48	47	47	47	47	47	47	47	47	47	47
Total	51	53	54	52	52	52	52	52	52	52	52	52	52

9.3.2. Loss ratio

Loss ratio is the ratio of losses (electricity entering the system less energy delivered to ICPs) over electricity entering the system.

Table 9-3: Loss ratio

Loss Ratio (%)	Historical			Forecast (%)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Dunedin	5	5	2	5	5	5	5	5	5	5	5	5	5
Central Otago/Wānaka	7	7	2	7	7	7	7	7	7	7	7	7	7
Queenstown	6	5	2	5	5	5	5	5	5	5	5	5	5
Total	5	6	2	6	6	5	6	6	6	6	6	6	6

9.3.3. Total transformer capacity utilisation

Total transformer capacity utilisation is the maximum coincident demand divided by total distribution transformer capacity.

Table 9-4: Transformer utilisation

Transformer Utilisation (%)	Historical			Forecast (%)									
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Dunedin	37	32	35	35	35	35	36	36	36	36	36	36	36
Central Otago/Wānaka	21	26	20	22	22	23	23	23	23	23	23	23	23
Queenstown	36	39	37	37	37	37	37	38	38	38	38	38	38
Total	31	30	30	30	30	31	31	31	32	32	32	32	32

9.4. IMPACTS OF CLIMATE CHANGE

9.4.1. Decarbonisation scenarios

We have developed three decarbonisation scenarios: *Sustainable*, *Chaotic*, and *Alternative Energy*. While the scenarios are qualitative descriptions of the range of futures, they allow quantitative results to be derived, specifically providing insight into changes in peak electricity demand and energy delivered through the network. In turn, this gives Aurora Energy an indication of expenditure required for a range of futures and highlights the importance of developing a strategy and action plans to manage this expenditure.

In developing the scenarios, we considered transport electrification (residential, light EV and heavy EV charging), lighting transition (residential, commercial and industrial), process heat transition (commercial and industrial), space/water heating and cooking for residential), PV (residential and commercial), and underlying load and population growth.

Figure 9-2 and Figure 9-3 show examples of peak demand (5:30pm in wintertime) for each scenario for the sub-networks in Dunedin and Central Otago, respectively. Winter at 5:30pm is a relevant time period because the peak demand on the system and all GXPs is in winter and typically would occur at around that time.

While the Chaotic scenario shows higher demand, the Sustainable and Alternative scenarios have almost the same peak demand. The main difference between the Sustainable and Alternative scenarios is that the former optimises the use of the network whereas the latter regresses in the use of the network.

Based on these three scenarios, it is prudent to plan our network and investments based on the Sustainable scenario.

Figure 9-2: Forecast peak demand per scenario: Dunedin

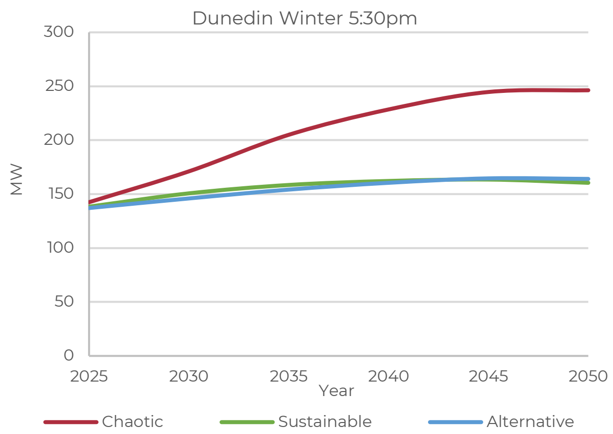


Figure 9-3: Forecast peak demand per scenario: Central

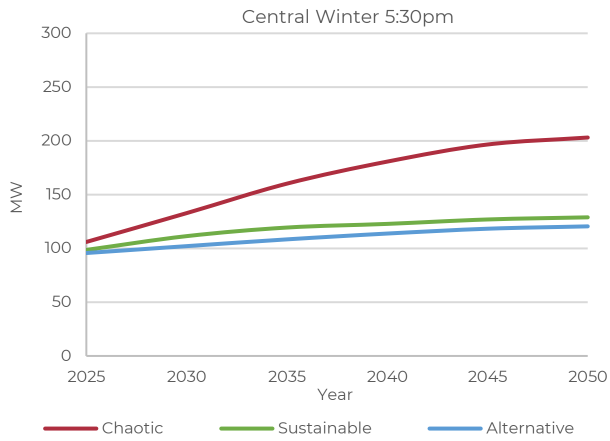
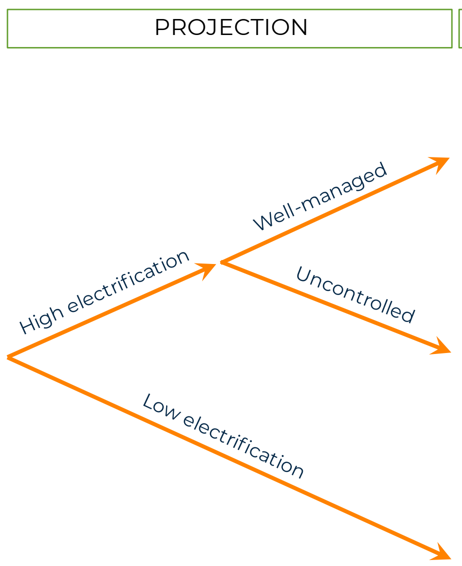


Figure 9-4 shows the implications of each scenario from the perspectives of the network and consumer. These viewpoints indicate that the Sustainable scenario would be the best outcome, so we are planning our investment accordingly. Under this scenario, we will optimise expenditure on network capacity and consumers will benefit from a lower increase in electricity prices.

Figure 9-4: Decarbonisation scenarios and implications

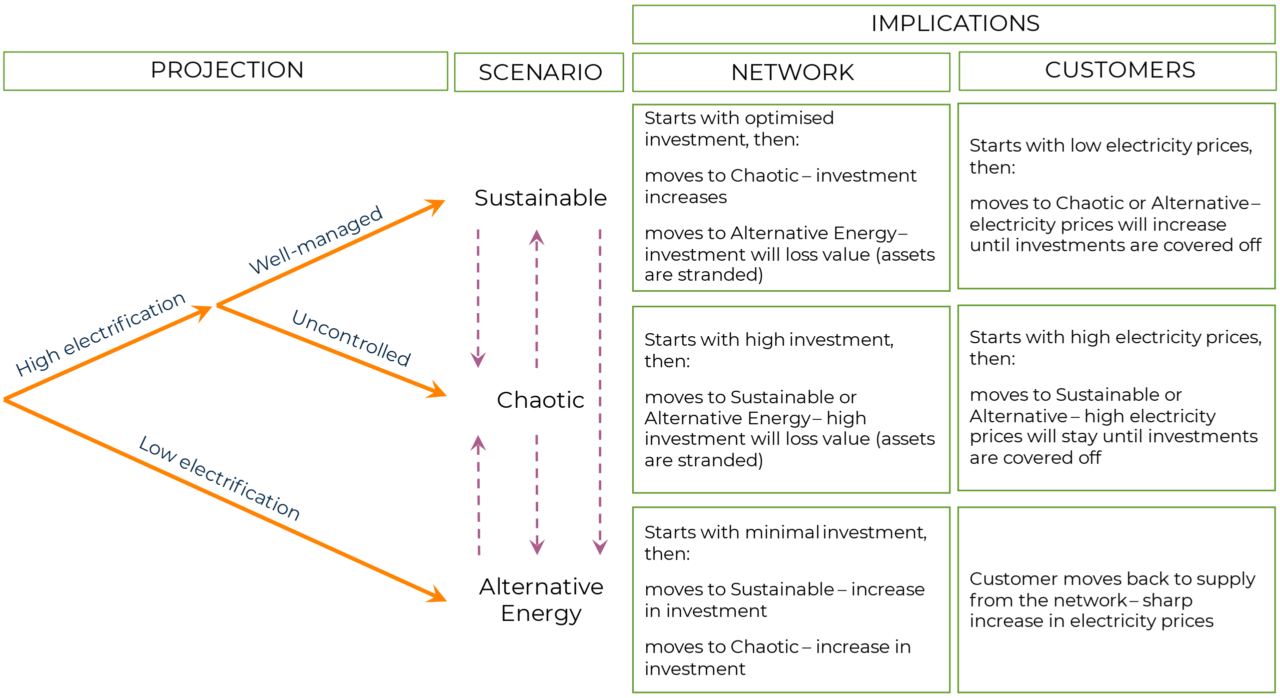


SCENARIO	IMPLICATIONS: NETWORK	IMPLICATIONS: CUSTOMERS
Sustainable	Managed use of DER Peak demand is minimised and energy increases Investment is optimised	Aurora Energy provides a sustainable network service where customers' DERs contribute to network operations Low increase in electricity prices
Chaotic	Uncontrolled use of DER Peak demand increases, resulting in high investment Energy grows modestly	High investment to meet increase in peak demand High electricity prices
Alternative Energy	Alternative energy source is used Minimal network investment as peak demand is minimised	Customers see greater incentive to shift to alternative energy

The Sustainable scenario requires careful management of peak demand as energy use increases over time. This would allow us to deliver an increase in energy without specifically needing to invest in additional or upgraded network assets (noting that the network will still need to extend to supply new subdivisions and commercial developments).

We must be consistent in our expenditure approach and avoid moving between scenarios, as this is effectively an extreme version of the Chaotic scenario, which brings the greatest disadvantage: high expenditure resulting in high electricity prices and underutilisation of assets. Figure 9-5 illustrates this view.

Figure 9-5: Moving from one scenario to another



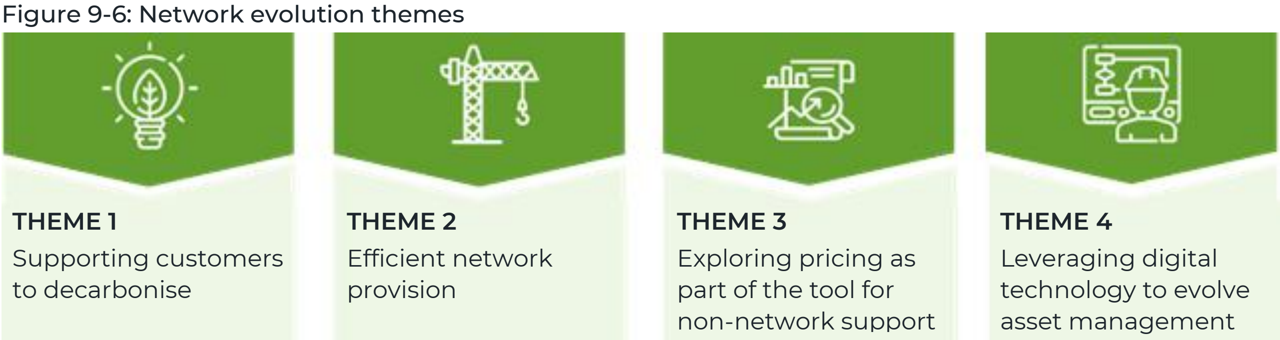
9.4.2. Impacts of climate risk

Our network is planned and built based on security of supply. We consider supply resiliency in areas of the network that require a high level of security such as the CBD. We are continually increasing transfer capacity between substations to further improve resiliency and have included budget for resiliency in our 10-year expenditure plan. We acknowledge that the changing weather conditions and increase in the number of severe weather events are having a great impact on the network and consumers.

9.5. NETWORK EVOLUTION

Our network evolution plan prepares Aurora Energy for a future in which electricity plays a key role in decarbonisation. We consider DER to be an important tool for managing the distribution network and will support consumers' adoption of EVs, PVs, battery storage, PV-battery, and other future forms of DER on our network. However, we also recognise that DER solutions in the low voltage network will contribute to network constraints including power quality issues if left unmanaged.

Figure 9-6: Network evolution themes



9.5.1. Network evolution themes

Figure 9-6 above summarises our four key network evolution themes. The sections that follow describe these themes in greater detail.

THEME 1: SUPPORT CONSUMERS TO DECARBONISE

SOLAR GENERATION UPTAKE

Distributed generation (DG) connections undergo a seamless connection process for small-scale (<10 kW) or large-scale (>10 kW), which helps us understand the location and size of solar generation in our network. The connection process is described in Section 4.4.

Figure 9-7 shows the 10-year uptake of solar generation in our network. This year's total solar generation capacity is 20 MW, which equates to 6% of the system maximum demand, with over 3,000 connections.

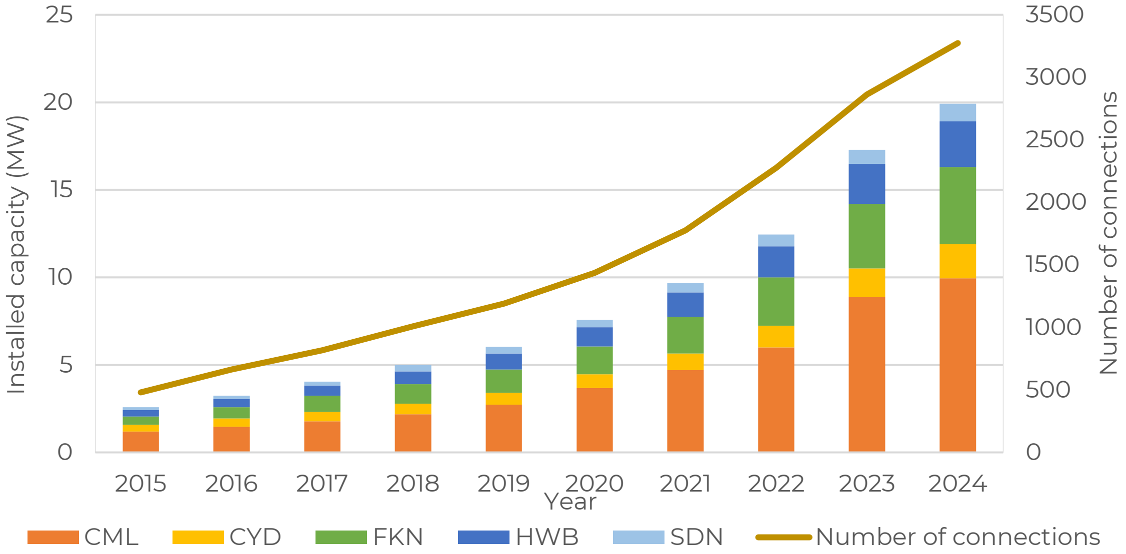
Since 2020, total installed solar capacity has grown by an average of 2.5 MW annually, with 368 yearly connections.

Cromwell GXP has the highest solar installed capacity with 10 MW and an annual increase in the last five years of 1.25 MW, which is 50% of the total solar installed capacity.

In the last five years, uptake has increased by an average of 28% per year, up by 4% from the previous five years. We expect the uptake of solar panels (and batteries) will continue to grow as more consumers adopt the technology.

These instances of small-scale solar DG are connected to the low voltage network, and at this stage have not resulted in power quality issues.

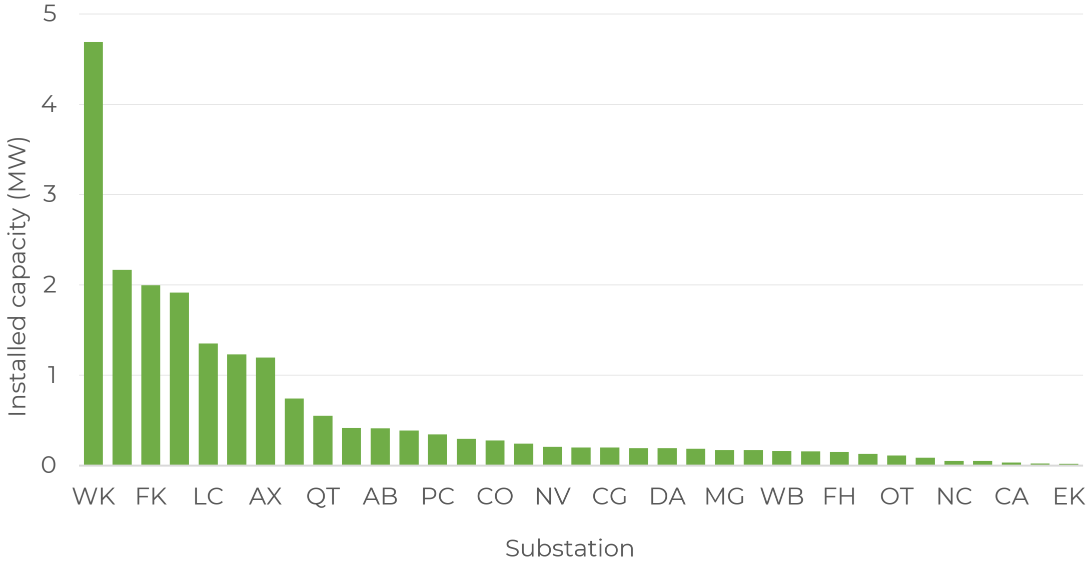
Figure 9-7: Solar generation 10-year uptake



Note: 2024 values are as of September.

Figure 9-8 shows total solar installed capacity distribution per substation for the year 2024. Wānaka zone substation (WK) has the most solar installed capacity, with more than double that of the Cromwell zone substation (CM). Four of the five zone substations with the highest solar installed capacity are connected to the Cromwell GXP.

Figure 9-8: Solar installed capacity per zone substation in 2024



SOLAR GENERATION FORECAST

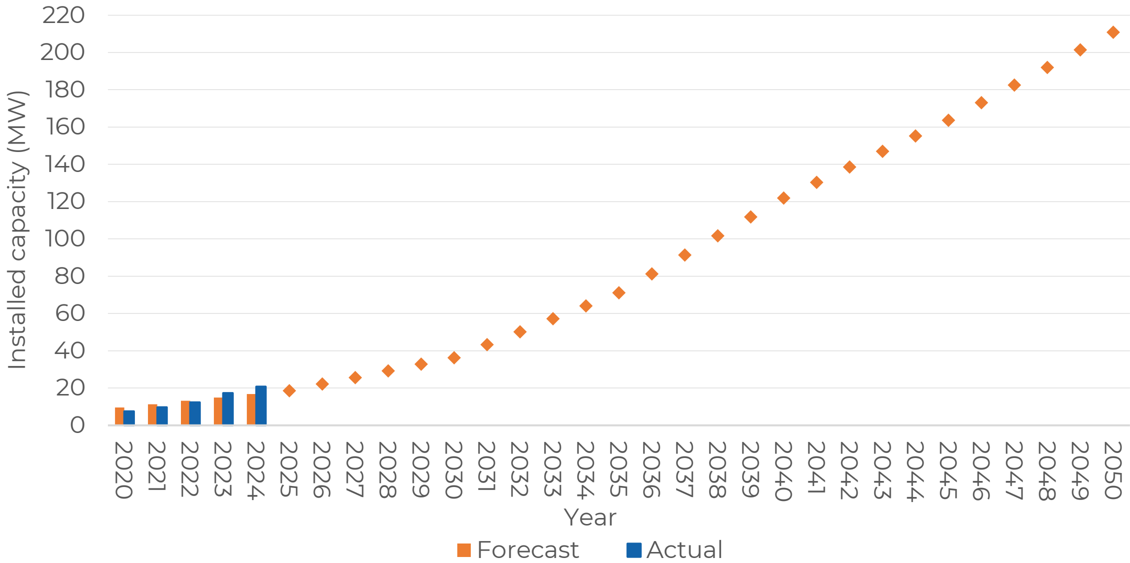
In our decarbonisation scenario study, we forecast solar generation capacity out to 2050. This provided us with a view of the generation capacity over the 30-year forecast period and enables us to monitor the actual uptake vs forecast, as shown in Figure 9-9.

Understanding the uptake and location of connections allows us to make better investment decisions (as described in Theme 4) to help consumers shift to PV technology.

Since 2023, there has been a surge in new installations, indicating that actual uptake has exceeded our forecast. This year, the uptake has been more than 3 MW above the forecast.

We note that the uptake curve will change over time, and we will review our forecast accordingly. As the cost declines, more consumers will be able to adopt solar, thereby enabling them to exploit the benefits and opportunities for value stacking as discussed in Figure 9-16.

Figure 9-9: Solar generation installed capacity forecast v actual



RESIDENTIAL ELECTRIC VEHICLE UPTAKE

Whereas solar generation goes through our connection process, residential EV chargers do not. However, because public EV chargers (e.g. ChargeNet, Z Energy, among others) go through our connection process, we do have visibility of these.

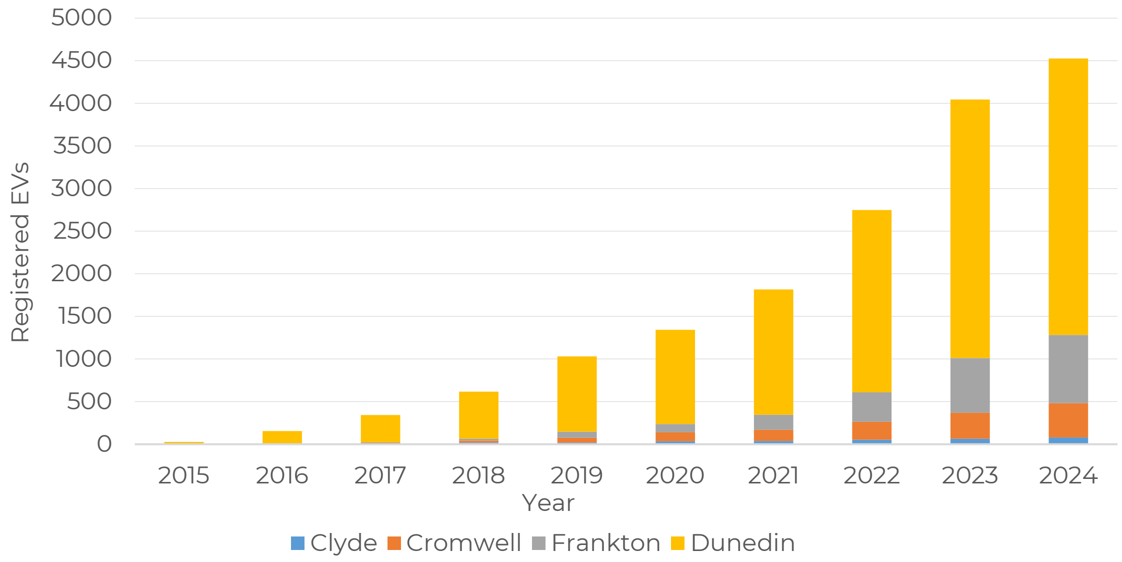
To date, no EDBs have visibility of residential EVs and their chargers, which means Ministry of Transport EV registration is the only available data source; however, this is of limited use.

There are about 4,500 EVs in our network, and we continue to see increases in total EV uptake. **Figure 9-10** shows the 10-year uptake of registered EVs.

Since 2020, there has been an average of 637 annual registrations of EVs. Most of these are in Dunedin (428 annual registrations), where the daily commute is short compared to Central Otago. Residential EV charging has not affected our LV network at this stage.

We envisaged that in the next few years there will be more smart EV chargers, as these can assist in mitigating increases in demand from households and the distribution network.

Figure 9-10: Registered residential electric vehicle 10-year uptake

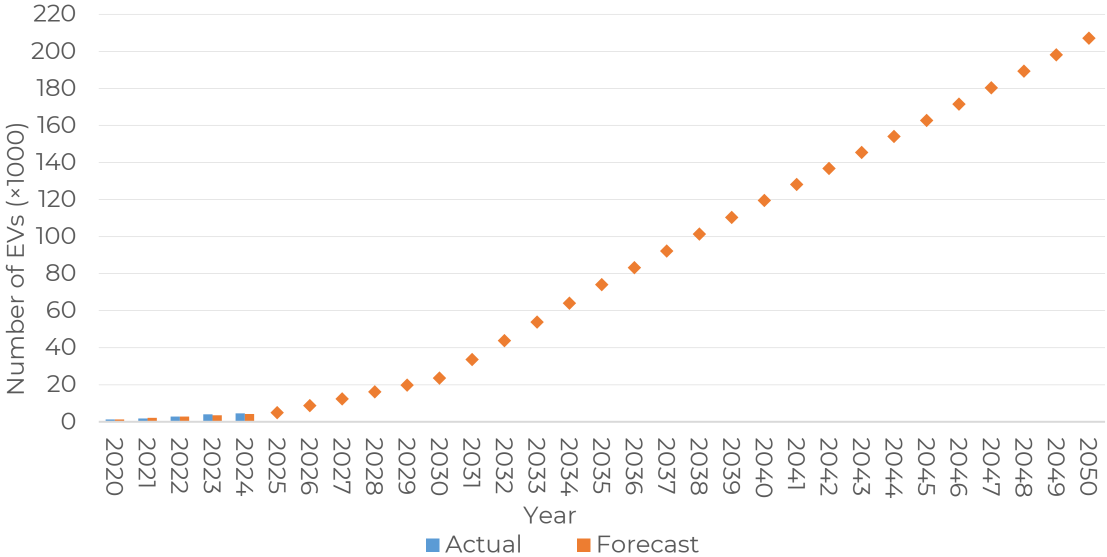


Note: 2024 values are as of September.

RESIDENTIAL EV FORECAST

In our decarbonisation scenario study in 2020 we forecast residential EV uptake out to 2050. **Figure 9-11** shows the actual uptake vs forecast. The actual is slightly higher than the forecast. The large increase in EV uptake was in 2023, with 1,300 more than the previous year. This year, EV uptake has only been half that of 2023. We will review our forecast with new information as it comes to light.

Figure 9-11: Actual registered residential electric vehicle uptake vs forecast



THEME 2: EFFICIENT NETWORK PROVISION

The Upper Clutha DER solution demonstrated the ability to utilise flexibility services such as solar batteries and hot water load to reduce load during constrained periods.

In 2021, Aurora Energy developed a flexibility management platform, allowing automated operation of Aurora Energy's hot water channels alongside the resources of a flexibility service provider (solar-battery). The platform utilises existing internal systems (OnDemand and SCADA).

The system is in operation, managing demand during constrained periods on the Upper Clutha subtransmission circuits.

The Upper Clutha DER solution has established benefits such as deferral of capex investment, asset capability optimisation, and reduction of demand. Further, the solution demonstrates that it is possible to identify and contract non-network solutions, that there is a market that can bring forward alternative viable ideas not previously considered, and that it is possible to orchestrate different flexibility services.

Figure 9-12, below, shows the DER solution development stage. On the following page, Figure 9-13 illustrates the system architecture and Figure 9-14 provides a functional view.

Figure 9-12 Upper Clutha DER solution development stages

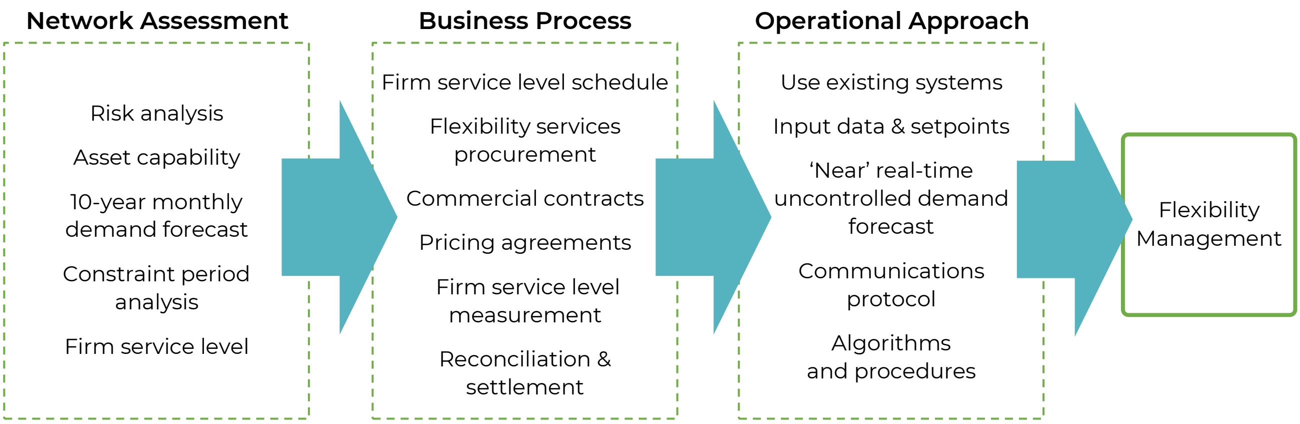


Figure 9-13: Flexibility Management – System architecture

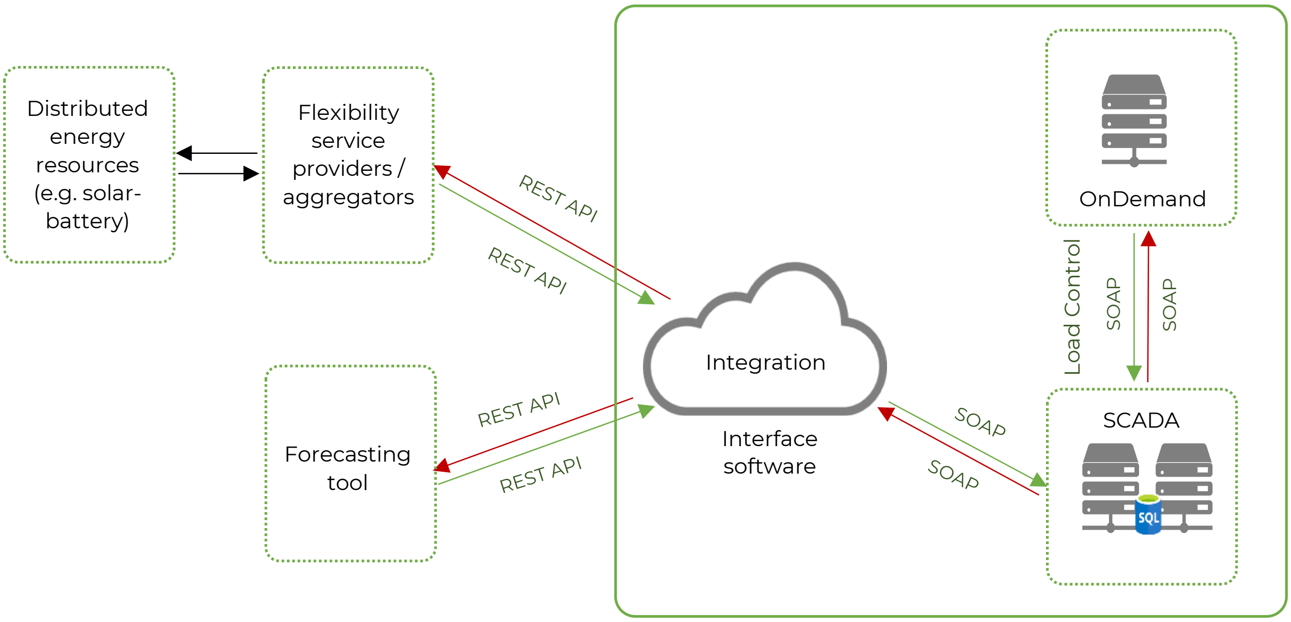
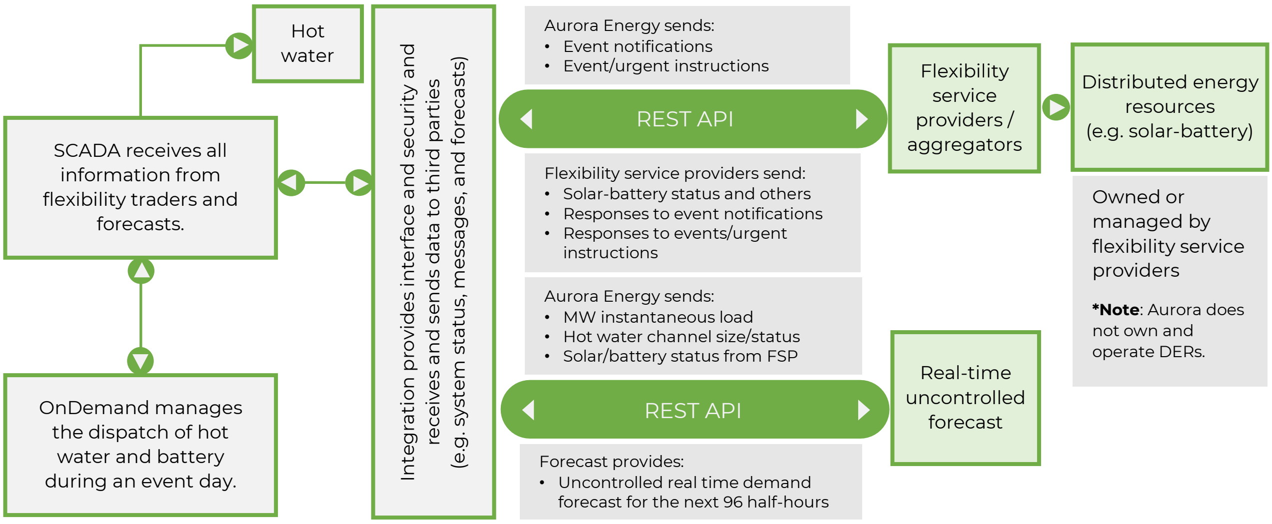


Figure 9-14: Flexibility Management - Functional diagram



FLEXIBILITY MANAGEMENT OPERATION

Figure 9-15 overleaf is an image from SCADA showing the operation of the flexibility management system over the period July 22 to 24, 2024. The top graph shows the controlled Upper Clutha load, and the bottom graph shows the operation of the flexibility management system.

The following is a step-by-step description of the automated operation shown in Figure 9-15.

July 22, 2024

20:00	**Event Day Tomorrow** notification is sent, conveying that on the next day (23 July) the forecast demand will be above the constraint target.

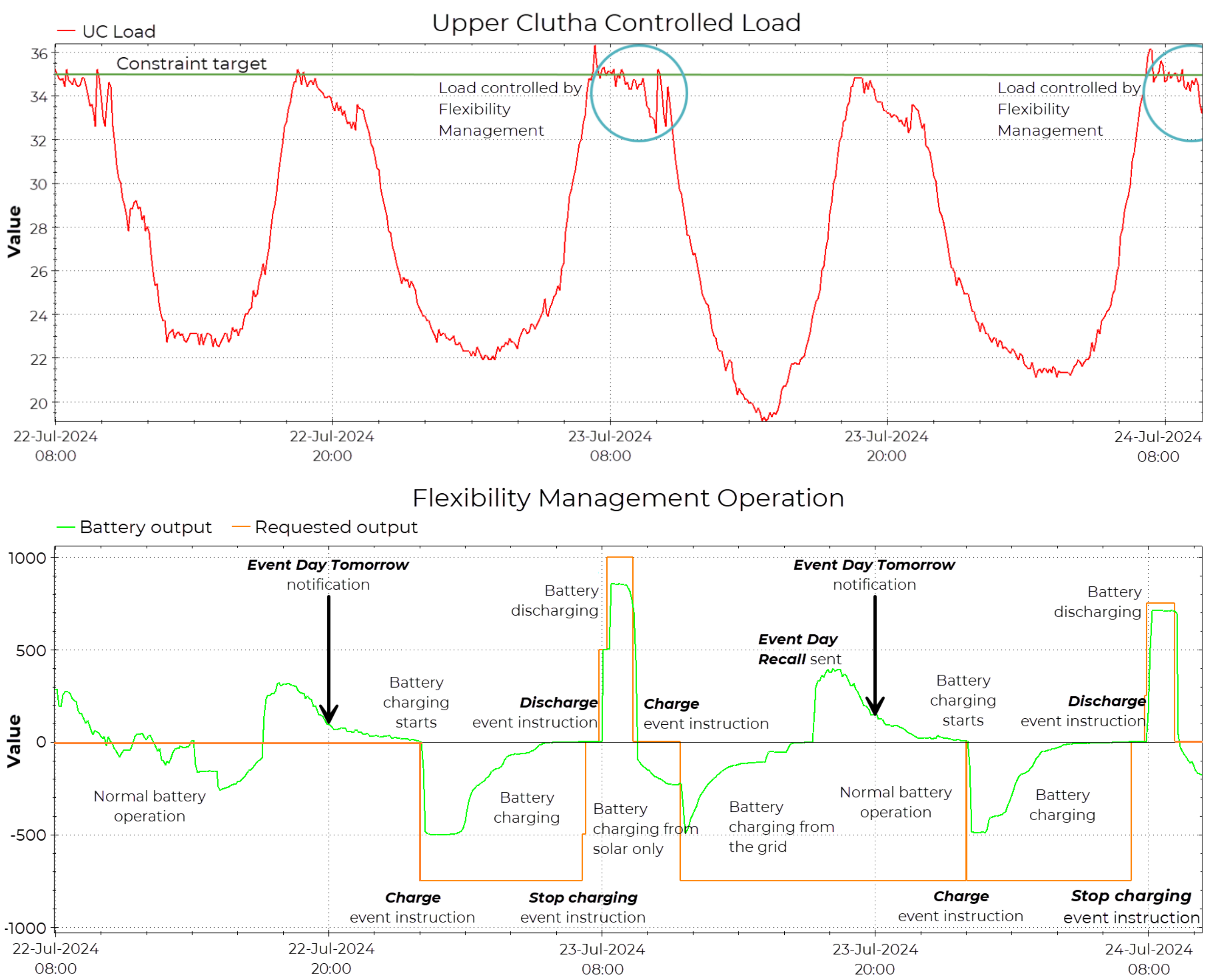
July 23, 2024

00:01	Event instruction to charge the batteries is sent.
07:00	Event instruction to stop charging the batteries is sent (batteries are fully charged).
07:30–10:00	Load above the constraint target. Hot water channels shed sequentially and an event instruction to discharge is sent, for the batteries to discharge to the network to reduce load.
10:00	Thereafter, the load decreases.
11:00	Hot water channels are sequentially restored.
12:00	Event instruction to charge the batteries is sent.
16:00	**Event Day Recall** instruction is sent, as the forecast shows that the evening peak is below the constraint target, and the batteries are returned to normal operation.
20:00	**Event Day Tomorrow** notification is sent, conveying that on the next day (24 July) the forecast demand will be above the constraint target.

July 22, 2024

The operation repeats.

Figure 9-15 Flexibility management operation



THEME 3: EXPLORING PRICING AS A TOOL FOR NON-NETWORK SUPPORT

Aurora Energy understands that in a two-way power flow system, there is a need to have a toolkit to fully achieve and optimise the use of DG on the network. We are currently working on how to use pricing as one of the tools we use for our expenditure decisions.

THEME 4: LEVERAGING DIGITAL TECHNOLOGY TO EVOLVE ASSET MANAGEMENT

LV VISIBILITY

To facilitate customers' decarbonisation aspirations and unlock and maximise the opportunities offered by the value streams from distributed energy resources, visibility is key.

Theme 1 shows the penetration of solar and electric vehicles in our low voltage network. Thus far, the level of penetration has not led to power quality issues, but we anticipate that usage will continue to increase leading towards 2050. That said, it should be noted that the LV network has been a passive network historically and spending after installation has tended to be reactive in nature.

Our preferred approach to achieving LV visibility is to combine smart meter network operating data with data from distribution transformer monitoring (DTM) devices installed at strategic locations. Used in conjunction with our internal systems (such as GIS), these data-sets provide an opportunity for us to develop an LV visibility platform with data analytics. Such a platform will provide us with a view of the LV network, allow us to perform data analytics, and enable monitoring.

This will allow us to take the initiative in low/high voltage occurrences and power quality issues; be proactive in identification of safety hazards (e.g. broken neutrals); optimise asset capability; improve network performance; enable operability of the LV network; and most importantly, improve our consumer service.

With the unexpected high cost and long contract duration associated with procuring smart meter network operating data, we have elected to conduct business cases for the procurement of smart meter network operating data and an LV visibility platform to better understand and inform our investment decision to move forward.

LV HOSTING CAPACITY AND LV CAPEX MODELLING

In the initial stages of the Upper Clutha DER solution project, Aurora Energy and ANSA Consulting conducted a study of hosting capacity in the Upper Clutha. The following year, a network-wide hosting study was conducted.

This year, we performed a hosting capacity study with updated LV GIS data, an improved hosting model, and more meter consumption data. We aim to conduct the study every two years and further increase the level of consumption data.

The study provides a snapshot in time and a forecast, based on penetration level, of the ability of the LV network to host (connect) PVs and EV chargers. This gives us an understanding of:

- The level of penetration and size of PV systems and EV chargers that can be connected to distribution transformers and to each LV network before we meet constraints (thermal and voltage)
- Constraints (existing and likely to occur) such as distribution transformer loading, LV feeder loading, or voltage incursions beyond the regulatory limit
- Sections of the LV feeder where constraints can potentially occur

GIS LV DATA QUALITY

The first stage of the DG hosting capacity study is to check the quality of Aurora Energy's LV network data. This stage contributes to continual improvement of our GIS LV data.

LV CAPEX FORECAST

This year, we have developed an LV network capex forecast using ANSA's LV Capex model. The model is based on a constraint risk analysis carried out in conjunction with the hosting capacity study. The capex forecast encompasses replacement of lines, cables, and distribution transformers identified as being constrained in future years based on EV and PV uptake scenarios or network reconfiguration if ANSA's model identifies this as a lower cost option for a given LV network.

The LV capex forecast will help with our investment decisions by enabling us to better prioritise investment options and understand how flexibility services might reduce capex expenditure requirements.

DIGITAL TECHNOLOGY

We continue to seek new digital technologies to aid asset management of the LV network, from the following perspectives.

- **Investment planning:** Understanding where and how much we should invest in the LV network over the AMP period based on the type of constraint
- **Managing constraints:** Identifying constraints that currently exist or are likely to arise, confirming the constraint, and identifying power quality issues to create new LV reinforcement/reconfiguration projects (in coordination with planned works)
- **Input to the SSDG and LSDG connection process:** Adopting a new traffic light system and visual representation of the study output, which can be incorporated into GIS and used in the DG connection process

9.6. NON-NETWORK SOLUTIONS

When the network becomes constrained, spending on new infrastructure may not necessarily be the best option to relieve the constraint. Non-network solutions can enable us to defer the much higher levels of capital expenditure that are usually associated with network solutions. This provides value in terms of lower lifecycle costs, while enabling us to defer a decision when there is considerable uncertainty (such as regarding future load growth).

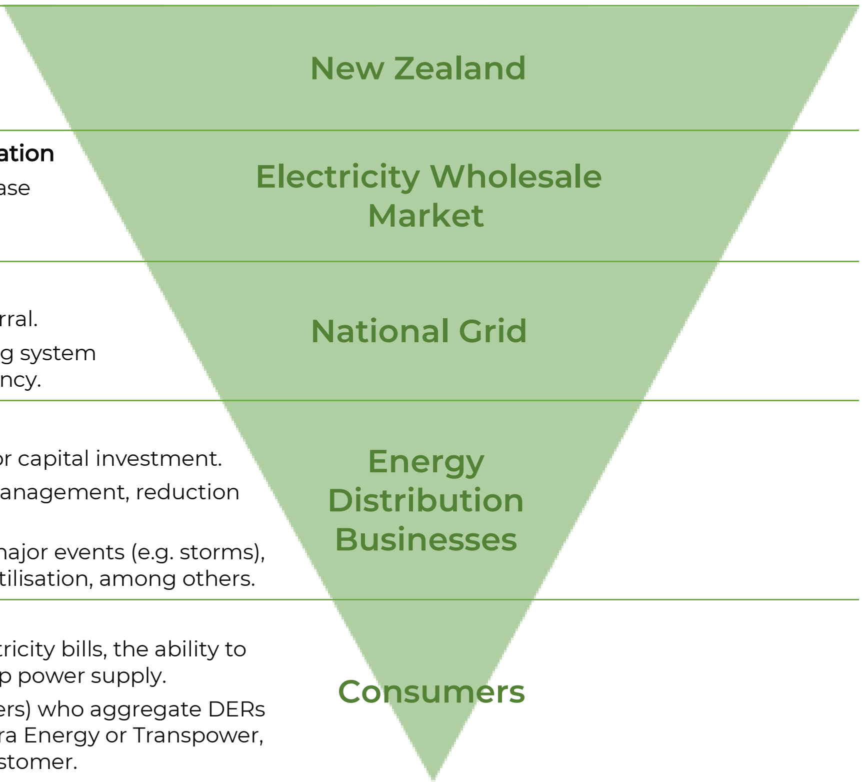
Other alternatives to network solutions include those listed in Table 9-5.

Table 9-5: Non-network solutions

Non-network solution	Description
Flexibility services	We actively consider flexibility services for two main purposes: • To defer known short-term subtransmission expenditure. We have demonstrated with the Upper Clutha DER solution (with solarZero) that flexibility services can be utilised to help manage demand during constrained periods, which provides the opportunity to defer large investments. • To shape long-term demand to help defer LV and HV network investment. This second purpose is becoming an increasing focus of our pricing and flexibility contracting.
Demand-side management	Demand side management (DSM) provides an alternative to network reinforcement. Generally, DSM involves altering consumer behaviour through the use of incentives provided by the distribution business (or retailer). The key difference between DSM and DER is the greater flexibility of the latter. DER also has the ability to export or manage energy in both directions, whereas DSM cannot reverse the flow of energy.
Cost-reflective pricing	It is anticipated that many different types of consumer devices, including DG and battery storage, will be connected to electricity networks in the future. These new devices will be able to respond to price incentives facilitated by time-of-use smart metering. Cost-reflective pricing will be a key enabler, providing financial benefits to households and businesses that purchase DERs. Further deployment of smart meters that provide half-hourly metering will facilitate benefits to consumers who own smart appliances that can move load away from peak pricing periods. Carefully constructed pricing will enable us to maximise the potential gain from smart metering and the future uptake of DER and smart appliances.
Value stacking	DER in the community provides value-stacked benefits for consumers, electricity distribution businesses, Transpower, and New Zealand. Value stacking provides the greatest benefit as it maximises the value of DER to multiple benefactors. This is the model we used for Upper Clutha capacity support.

Figure 9-16 illustrates how value stacking works and how the benefit is translated from one consumer to New Zealand. In this example, the consumer has a PV-Battery system.

Figure 9-16: Value stacking



Encourages increased uptake and acceptance of the technology, and ultimately supports the nation's decarbonisation goal.

Wholesale Electricity Market – Generation

Benefits by enabling optimisation of base load generation with new intermittent renewable electricity generation.

National Grid – Transpower

As grid owner, capital investment deferral.

As system operator, assists in managing system stability in terms of voltage and frequency.

EDBs like Aurora Energy

Deferral or potential avoidance of major capital investment.

Network benefits such as constraint management, reduction of everyday peaks.

Supports network restoration during major events (e.g. storms), voltage support, and increased asset utilisation, among others.

Consumers with DER

Benefits in the form of savings on electricity bills, the ability to export excess generation, and a backup power supply.

Working with flexibility traders (suppliers) who aggregate DERs and provide services to EDBs like Aurora Energy or Transpower, providing additional benefits to the customer.

Chapter 10

NETWORK DEVELOPMENT

Network development is about expanding our network into new areas or increasing the capacity or functionality of our existing network to meet the current and future needs of our consumers in a cost-effective manner.

10.1. NETWORK DEVELOPMENT PLANNING

Network development planning requires us to anticipate potential shortfalls of capacity or breaches of our criteria for security, reliability and power quality under forecast demand conditions. We consider both network and non-network options in our planning processes, and plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

10.1.1. Key planning assumptions and inputs

The key inputs informing our network development planning analyses are:

- Historical demand data, by zone substation, subtransmission and GXP, used for forecasting electricity demand
- Information obtained from local councils, developers, irrigators, and other parties reflecting developments expected to impact electricity demand (proxy for economic activity)
- Network performance commitments made to consumers and stakeholders
- The current configuration of our network
- Manufacturer nameplate ratings, equipment thermal ratings, and other factors impacting our equipment ratings
- The availability of large embedded generation following a major power outage
- Voltage requirements and other regulated limits

Key assumptions informing our planning are:

- The uptake of new technology such as EVs, batteries and solar generation will accelerate, but will have only modest or clustered network impacts in the planning period
- Existing levels of hot water load management, through ripple control, are reflected in the historical data and will be reflective of future levels of demand management. In the future, we will potentially share hot water load management with retailers and other flexibility traders
- Thermal fuel transition to electricity will impact distribution feeders and zone substation demands, and we are working with the relevant customers to understand their transition journey
- Industry rules will remain broadly stable and will not lead to step changes in security or reliability of supply requirements

10.1.2. Security of supply

Security of supply (SOS) is the ability of a network to meet the demand for electricity when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform and/or the quicker it can recover from a fault.

Managing system security is a key driver of growth and security expenditure. We establish appropriate SOS criteria and apply these in our network development process to identify investment needs. Our SOS criteria (for GXPs, subtransmission, and distribution networks) are set out in Table 10-1.

Security criteria establish a required level of network redundancy. The degree of redundancy determines the ability of the network to maintain supply following the failure of an asset component. We specify our security criteria to support our performance objectives and the reliability performance sought by our consumers and stakeholders. Security criteria generally drive the larger investments related to the subtransmission system and zone substations, which directly impact the level of reliability experienced by large numbers of consumers.

Security guidelines are normally defined in terms of *N–X*, where *X* is the number of coincident outages that can occur during periods of high demand without extended loss of supply to consumers. At the levels of load encountered at most of our zone substations, N-1 is the optimal consideration (i.e., an outage on the single largest circuit or transformer can occur without resulting in a supply interruption).

Zone substation security levels can also be specified by the time allowed to restore supply through network reconfiguration after an asset fails, including allowable switching time before all loads can be restored.

Feeder classifications provide information on the network or the types of loads supplied by a zone substation and therefore influence its security classification.

Distribution feeder security guidelines are established for each feeder type depending on the type of load. Higher levels of redundancy or backfeed capacity are required where more consumers could be affected by an outage. The load type provides a proxy for the expected economic impact of loss of supply to that load (or customer).

Effective tailoring of security guidelines for individual customers, particularly in the mass-market or at lower voltage levels, is impractical. Thus, our current security criteria are defined at HV feeder level and above only.

It is important to distinguish between reliability of supply – the actual performance of the network in terms of the amount and duration of interruptions – and security of supply – as described in the beginning of this section. When planning for load growth, we aim to optimise the level of security and fault tolerance at a level that is acceptable to consumers. This necessitates a balance between infrastructure expenditure and operational cost.

Infrastructure expenditure is driven by security of supply requirements, while the reliability of supply achieved depends on a combination of security of supply and operational performance.

Table 10-1: Security of supply criteria for GXPs, subtransmission, and distribution networks

Class	Description	Load (MW)	Cable, Line, or Transformer Fault	Double Cable, Line, or Transformer Fault	Bus or Switchgear Fault
Grid Exit Point (GXP)					
CBD/Urban	GXPs supplying predominantly metropolitan areas, CBDs, and commercial or industrial customers	15–200	No interruption	Restore within two hours	No interruption for 50% and restore remainder within two hours
Rural/Semi-rural	GXPs supplying predominantly rural and semi-rural areas	15–60	No interruption	Restore within four hours	No interruption for 50% and restore remainder within four hours
Substation					
Category Z1	Predominantly metropolitan areas, CBDs, and commercial or industrial customers	15–24	No interruption	Restore within two hours	No interruption for 50% and restore remainder within two hours
Category Z2	Predominantly metropolitan areas, CBDs, and commercial or industrial customers	0–15	Restore within two hours (may include use of mobile substation)	Restore 75% within two hours and remainder in repair time	Restore in repair time
Category Z3	Predominantly rural and semi-rural areas	0–15	Restore within four hours (may include use of mobile substation)	Restore in repair time	Restore in repair time
Distribution Network					
Category F1	Predominantly metropolitan areas, CBDs, and commercial or industrial customers	1–4	Restore all but 1 MW within two hours and remainder in repair time*	Restore in repair time	Restore all but 1 MW within two hours and remainder in four hours (using a generator)
Category F2	Predominantly metropolitan areas, CBDs, and commercial or industrial customers	0–1	Restore in repair time*	Restore in repair time*	Restore in repair time*
Category F3	Predominantly rural and semi-rural areas	1–4	Restore all but 1 MW within four hours and remainder in repair time*	Restore in repair time*	Restore all but 1 MW within four hours and remainder in repair time*
Category F4	Predominantly rural and semi-rural areas	0–1	Restore in repair time*	Restore in repair time*	Restore in repair time*

* Generators to be used where feasible to enable restoration of power before fault is repaired.

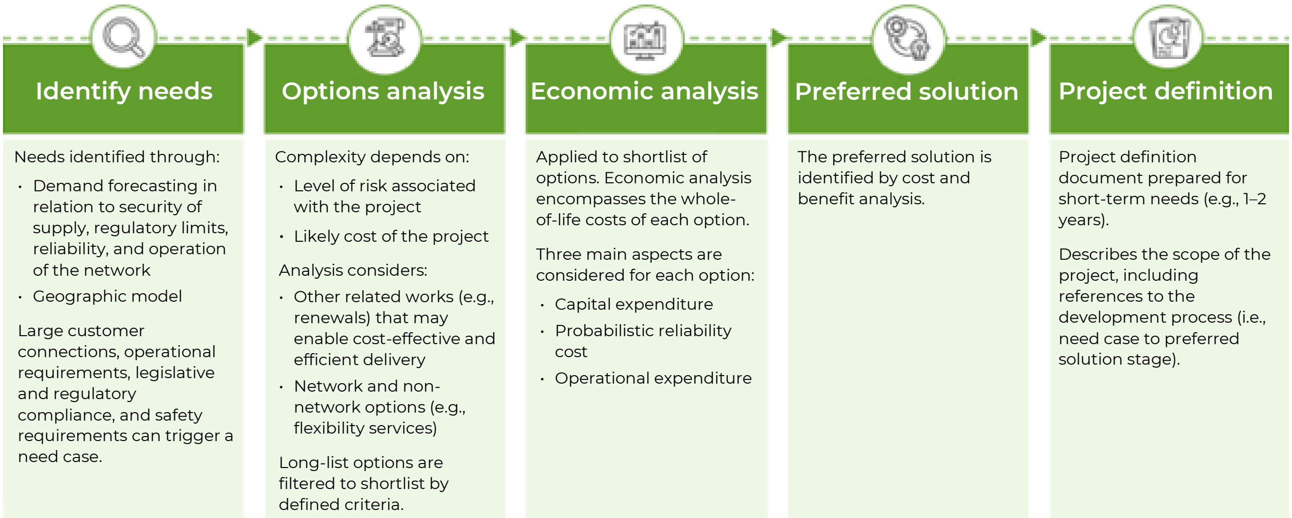
10.2. NETWORK DEVELOPMENT PROCESS

In this section, we describe our approach to planning capital network development expenditure for system growth, security, reliability, and power quality.

This explains how we ensure our expenditure prudently supports our asset management objectives. Figure 10-1 shows the entire process.

We capture medium-term (3–5 years) projects in a business case paper and long-term (6–10 years) projects in a high-level paper.

Figure 10-1: Network development process



10.3. DEMAND FORECASTING

Demand forecasting is a key input for determining expenditure requirements. To effectively plan for growth, we need to forecast future peak demand. Changes in the forecast from one year to the next may result in planned projects being brought forward or deferred. Our focus is on peak demand (rather than energy), as this primarily drives the need for network development.

While many factors affect demand, the two main drivers of growth are population growth and economic activity. To an extent, these two factors are related. Demand is also impacted – albeit to a much lesser degree – by changes in behaviour and usage. Improved energy efficiency is one example of this. Looking forward, uptake of new technologies (for example, photovoltaic generation, battery storage, combined PV-battery systems, EV charging) will likely be the major cause of changing demand patterns.

Electrification of thermal process and transportation driven by decarbonisation will certainly impact electricity supply, although at this stage it is uncertain how this will evolve.

Other electricity transitions that are likely to impact demand are residential cooking, space heating and water heating, and commercial and industrial lighting. We have incorporated these in our demand forecasting tool to give us a view of peak demand in the 10-year AMP plan.

As one of the actions from the decarbonisation study, we have included decarbonisation levers in our demand forecast. We forecast demand in annual and monthly peaks, looking 10 years into the future at the GXP, subtransmission, and zone substation levels.

We also consider future load on HV feeders, if necessary, by adjusting for any known step changes – for example, new subdivisions and council plan changes. We have implemented a system of triggers for individual feeder analysis. For example, feeder analysis would be triggered when peak load reaches a specified percentage of nominal feeder capacity, number of customers, or security.

The demand forecast is based on our *sustainable* growth scenario.

DEMAND FORECASTING TOOL

We produced two sets of 10-year demand forecasts as our baseline: *Expected* and *Prudent*.

The expected forecast is the base growth forecast, with known parameters (such as underlying growth or known load) added.

For the prudent forecast, we take the expected forecast and add extra growth to account for potential demand growth. For example, we might have allowed a 2 MW load for four years (0.5 MW each year) for the expected forecast; but with accelerated development, this may become 2 MW in two years.

Thus, the expected forecast triggers projects, while the prudent forecast triggers the start of planning. The gap between the expected and prudent forecasts depends on the growth of an area, so a high growth area will have a bigger gap between the expected and prudent forecasts.

Demand forecasts are prepared for the total system, GXPs, subtransmission, and zone substations.

We have not adjusted for weather effects. The effect of weather is generally dampened out over the course of the year; however, as more data becomes available, it may be necessary to factor the impact of a changing climate into our forecasting.

Figure 10-2: Diagram of the forecasting tool

***Peak normalization process:** Transferred load is added back to the donor substation, disregarding peaks among others.

ADDITIONAL FORECASTING FOR INFORMATION DISCLOSURE REQUIREMENTS

The following methods are used to forecast information required for information disclosure and help inform commercial and planning aspects of the business.

- **Customer connections:** We use a rolling average method to reflect trends in the number of new customer connections. Using this method, we have observed a minor slowing in the growth rate of new connections.
- **Distributed generation (DG):** Our demand forecast is based on our *sustainable* scenario DG assumptions.
- **Electricity volumes:** We have normalised the growth rate over the past five years for the effects of the Covid-19 pandemic and applied this rate to forecast electricity volumes for the next six years.

The data produced is not used directly for expenditure forecasting, as forecasts of final consumer connections do not correlate well to consumer connection capex. This is due to variability in the work required to connect larger installations and the fact that subdivisions take several years to be fully built out, depending on property market conditions.

FORECASTING UNCERTAINTY

Inherent to our demand forecast is the level of uncertainty in the 10-year planning horizon, which is amplified from the medium term (3–5 years) and more so with regard to the long term (6–10 years). This increased uncertainty over longer forecast periods is influenced by many factors, including but not limited to the drive for decarbonisation, uptake of new and emerging technologies, regulations, and potential changes to the power system landscape accompanying increased utilisation of flexibility services. Further, uncertainty is exacerbated by the timing of large load and generation developments.

Electrification of large transportation – for example, planes, ferries and cruise ships, or any electrification of port facilities (maritime, land, or air) provides a high level of uncertainty. These types of electrification will have a significant impact on the network, so we are monitoring and collaborating with key contacts at Port Otago, Dunedin International Airport, and Queenstown Airport.

NETWORK MODEL

Using PowerFactory modelling software, we have created two geographical network models in representing our three sub-networks. These show the sub-networks from the GXP to the distribution transformers, and also include embedded large generation and embedded networks (defined as load only). This has enabled us to develop a better understanding of the capability and constraints on our network.

We use the PowerFactory model with the demand forecast to methodically analyse the network with regard to capacity, security, reliability, and regulatory voltage limits in the 10-year planning horizon.

We conduct network studies for outage planning, reconfiguration of the network for operational mitigation, contingency, fault analysis, and protection studies among others.

10.4. SYSTEM DEMAND AND INVESTMENT

Using the demand forecasting approach described above, we also review actual historical demand. Table 10-2 outlines the total historical network demand by GXP. As the table shows, generation reduces the system peak demand through the GXPs by an average of 18%.

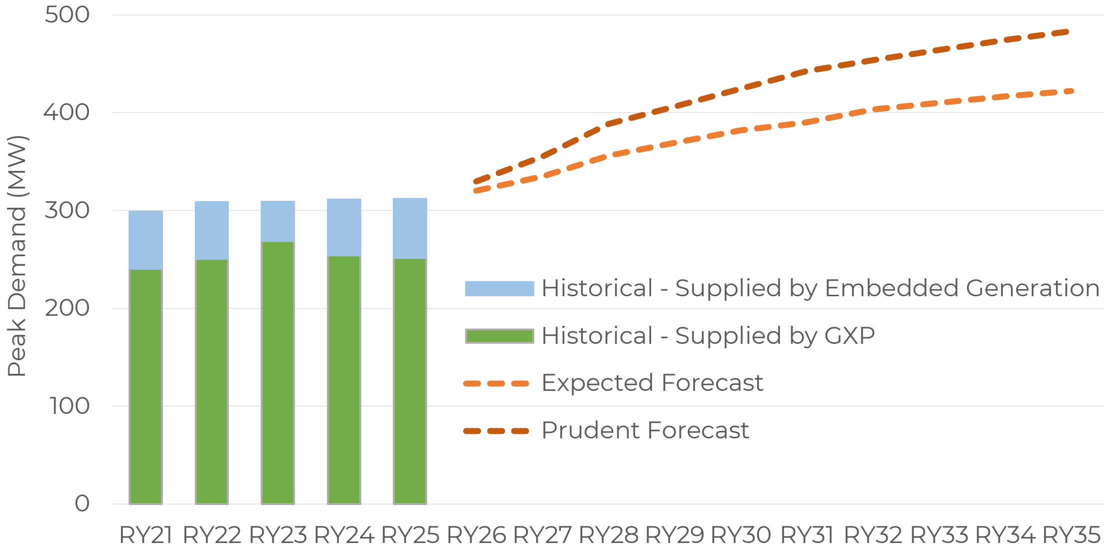
The system peak demand typically occurs in winter. This year's system peak demand was almost the same as last year's. Figure 10-3 shows a continuous increase in system peak demand from 2021.

Table 10-2 also shows that the Wānaka and Queenstown regions have been experiencing significant growth since 2016. In the last ten years, demand at both Cromwell GXP and Frankton GXP saw an average increase of more than 2 MW per year. This year, demand at both GXPs rose by 5 MW and 7 MW respectively compared to the previous year.

Table 10-2: Historical peak demand (MW)

Sub-network	GXP	RY16	RY17	RY18	RY19	RY20	RY21	RY22	RY23	RY24	RY25
Dunedin	Halfway Bush	127	120	128	122	118	118	119	121	123	117
	South Dunedin	77	69	71	67	75	75	75	73	73	72
Central Otago and Wānaka	Cromwell	34	35	37	39	44	44	47	49	49	54
	Clyde	19	18	19	19	19	19	18	19	20	19
Queenstown	Frankton	57	58	61	61	69	69	72	72	75	82
Total system demand		**291**	**291**	**300**	**299**	**283**	**299**	**309**	**309**	**311**	**312**

Figure 10-3: Total system demand



Although we are monitoring a slight softening in residential demand in Dunedin, the total system forecast indicates an increase in demand during the 10-year plan. The majority of the increase is in the Central Otago & Wānaka and Queenstown sub-networks, where significant demand growth is happening and is forecast to continue through the 10-year horizon.

The demand forecast is based on the *sustainable* scenario and we create our investment plans to resolve network gaps with minimum viable plans, taking into consideration the impact on our customers.

For our planned growth-related projects, see **Appendix F**.

10.5. DUNEDIN SUB-NETWORK INVESTMENT

The following sections describe the demand forecast, network gaps, and expenditure for the Dunedin sub-network.

10.5.1. Halfway Bush demand

Halfway Bush GXP and zone substation demand forecasts are shown in **Figure 10-4** and **Table 10-3**.

Figure 10-4: Halfway Bush GXP demand forecast

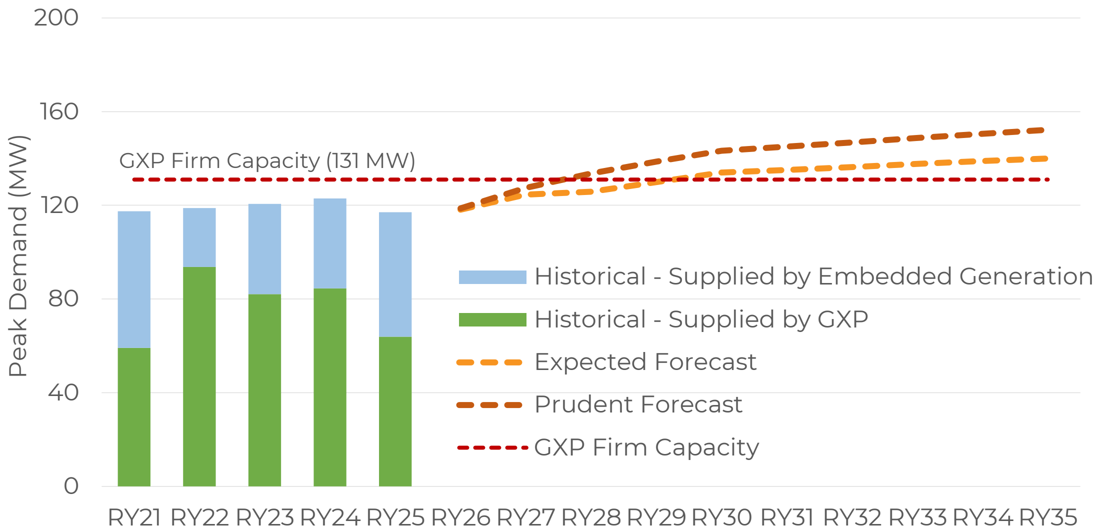


Table 10-3: Halfway Bush zone substation demand forecast

Zone substation	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Berwick	Z3	2.7	N	1.4	1.6	1.6	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	Spring
East Taieri	Z1	22.9	N-1 Switched	18.7	18.0	18.6	18.4	18.6	18.9	19.1	19.4	19.7	19.9	20.1	20.4	20.6	20.8	20.9	Winter
Green Island	Z2	18	N-1	14.5	14.6	14.0	13.5	13.6	13.8	13.9	14.1	14.2	14.4	14.5	14.6	14.8	14.9	15.0	Winter
Halfway Bush	Z2	18	N-1	13.4	13.6	13.9	13.9	14.0	14.0	14.2	14.3	14.4	14.6	14.8	15.1	15.4	15.6	15.9	Winter
Kaikorai Valley	Z2	22.9	N-1	10.5	10.0	10.6	10.6	10.8	10.8	10.9	11.0	11.1	11.1	11.2	11.3	11.3	11.4	11.4	Winter
Mosgiel	Z2	12	N-1 Switched	7.2	7.1	7.3	7.0	7.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.9	11.0	11.1	Winter
North East Valley	Z2	14	N-1	10.4	10.4	10.8	10.6	10.7	10.8	10.9	11.0	11.1	11.2	11.3	11.4	11.5	11.5	11.6	Winter
Outram	Z2	7.5	N	3.2	3.3	3.0	2.9	2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.3	Winter
Port Chalmers	Z2	7.5	N-1	7.3	7.6	7.7	7.6	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.2	8.3	8.4	8.4	Winter
Smith Street	Z1	18	N-1	12.9	13.2	12.6	12.6	12.6	15.2	15.3	15.4	15.5	15.5	15.7	15.8	15.9	16.0	16.2	Winter
Ward Street	Z2	22.9	N-1	9.3	9.6	9.5	9.5	9.5	9.5	9.5	12.6	15.6	15.7	15.7	15.8	15.8	15.9	16.0	Winter
Willowbank	Z2	15	N-1	11.8	12.5	12.9	12.9	13.0	13.1	13.1	13.2	13.2	13.3	13.4	13.5	13.5	13.6	13.7	Winter

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

10.5.2. Network gaps

Key gaps between capacity and forecast demand for the Halfway Bush GXP are set out in Table 10-4.

Table 10-4: Halfway Bush GXP gaps

Area	Constraint	Status
Halfway Bush GXP	The forecast indicates that in the middle part of the AMP period the demand will be above the firm capacity of the GXP. However, the Waipori generation offsets 30% of the GXP load. Decarbonisation plans of Port Otago and Dunedin Airport will impact the capacity of the GXP. *Note:* Aurora Energy shares this GXP with another EDB.	We will conduct a study to understand the implications in the case that all or part of generation is out of service. We are in discussions with Port Otago and Dunedin Airport regarding their future plans.
Dunedin CBD 33 kV Subtransmission	The Halfway Bush and South Dunedin GXPs both supply the CBD but transfer capacity between GXPs is very limited. Most of the subtransmission circuits are in a radial configuration and there is a risk of loss of supply in a double circuit outage, as the two cables are installed in close proximity.	We have developed a plan to create a subtransmission ring configuration in the Dunedin CBD. This will increase security and reliability/resilience as the ring will enable zone substations to be transferred between GXPs. Our preferred plan is to combine the subtransmission cable renewal schedule with the creation of the subtransmission ring. The Smith Street to Willowbank 33 kV cable is currently underway and is projected to be completed in RY25. This allows deferral of the Willowbank gas cable renewal. The other projects scheduled for the latter part of the 10-year plan are North City to Ward Street, South City to Ward Street, South City to Carisbrook, and Smith Street to South City.
Port Chalmers Substation and Northeast Valley–Port Chalmers 33 kV Subtransmission	Port Otago may electrify its operations to meet their decarbonisation goals. However, the largest potential demand is the electrification of large ships (e.g. cruise ships). This will impact demand on the subtransmission from Halfway Bush GXP.	We will work closely with Port Otago to support their decarbonisation goal and to understand the power supply requirements of electric ships, as well as the associated timing.

Area	Constraint	Status
Port Chalmers Substation	The peak demand of Port Chalmers Substation in winter 2023 was above the firm capacity and is forecast to further increase.	A transformer replacement is planned for RY27–28 with larger size transformers to accommodate growth.
Berwick Substation	Berwick Substation is an N-security level substation with limited backfeed supply from Outram. For contingent events such as zone transformer failure, restoration of power supply is dependent on repair time.	We have created a backfeed project to be completed in RY25 to provide backup supply from Outram and limit the duration of an outage to only the switching time.
Outram Substation	Outram Substation is an N-security level substation but has transfer capability to adjacent zone substations. Outram Substation supplies Dunedin International Airport. Airport demand is likely to increase with decarbonisation.	Aurora Energy will prepare a contingency plan for loss of power supply. We are working with Dunedin International Airport on their decarbonisation plans.

10.5.3.South Dunedin demand

South Dunedin GXP and zone substation demand forecasts are shown in Figure 10-5 and **Table 10-5**.

Figure 10-5: South Dunedin GXP demand forecast

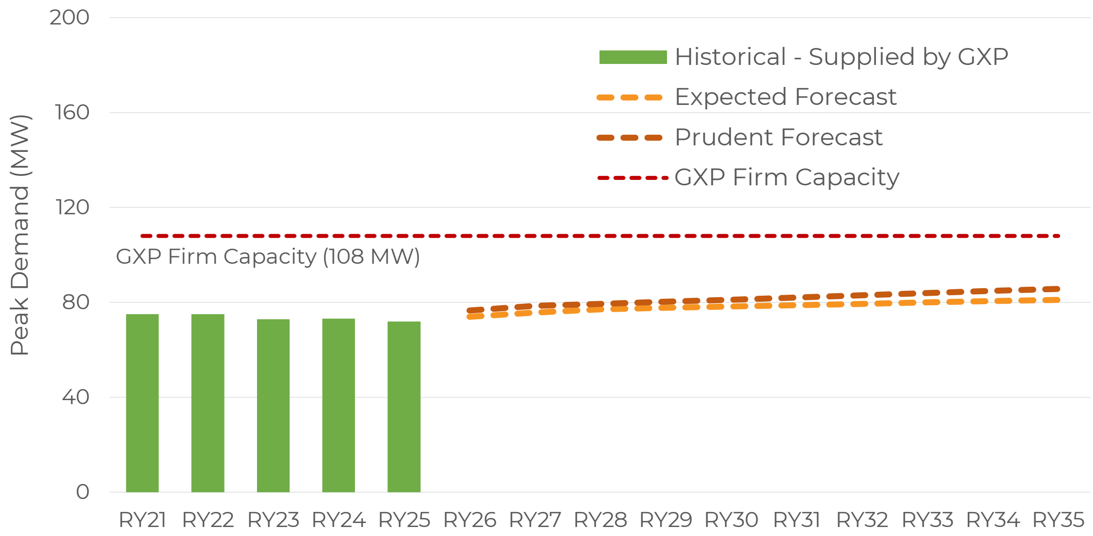


Table 10-5: South Dunedin zone substation demand forecast

Zone substation	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Andersons Bay	Z1	24	N-1	15.5	14.2	15.1	13.5	13.8	14.1	14.3	14.5	14.7	14.9	15.0	15.1	15.3	15.4	15.5	Winter
Carisbrook	Z2	22.9	N-1	12.1	9.5	10.5	10.5	10.5	11.2	11.3	11.5	11.6	11.8	12.0	12.2	12.3	12.5	12.7	Winter
Corstorphine	Z2	19	N-1	12.9	12.0	13.2	11.5	11.6	11.7	11.9	12.1	12.2	12.4	12.5	12.6	12.7	12.8	12.9	Winter
North City	Z1	28	N-1	15.3	15.4	14.8	14.8	14.8	15.5	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.3	16.3	Winter
South City	Z1	18	N-1	15.1	14.8	14.5	14.5	16.0	16.0	16.0	16.0	16.0	16.0	16.1	16.1	16.2	16.2	16.3	Winter
St. Kilda	Z1	22.9	N-1	14.6	14.6	15.4	13.9	14.1	14.2	14.3	14.5	14.6	14.7	14.8	14.9	15.0	15.1	15.2	Winter

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

10.5.4. Sub-network development investment

The major projects resulting from sub-network gaps identified are shown in Table 10-6.

Table 10-6: Major projects for the Dunedin sub-network

Major Projects	From	To	Capex ($m)
Smith Street to Willowbank 33 kV Intertie This project will install a 33 kV underground cable from Smith Street Substation to Willowbank Substation to increase security and resiliency by having the subtransmission capable of supplying either Willowbank or Smith Street as part of the Dunedin CBD 33 kV Subtransmission project.	2023	2025	5.5
PC-NV Subtransmission Thermal Upgrade This project is to increase the line ratings of the subtransmission by upgrading portions of the line.	2031	2031	0.6
Other Dunedin CBD 33 kV Subtransmission Projects			
South City to Ward Street	2031	2033	2.8
Smith Street to South City	2031	2033	3.6
South City to Carisbrook	2031	2033	6.5
North City to Ward Street	2033	2035	3.6

The distribution projects to be completed for the Dunedin sub-network are shown in Table 10-7.

Table 10-7: Distribution projects for the Dunedin sub-network

Distribution Projects	From	To	Capex ($m)
South City Feeder Reconfiguration This project is to support a customer's thermal transition.	2026	2026	0.1
Load Transfer from St Kilda to Carisbrook This project is to offload St. Kilda and increase capacity utilisation of Carisbrook Substation.	2029	2030	1.2

10.6. CENTRAL OTAGO & WĀNAKA SUB-NETWORK INVESTMENT

The following sections show the demand forecast, sub-network gaps, and expenditure for the Central Otago & Wānaka sub-network.

10.6.1. Cromwell demand

Cromwell GXP zone substation and subtransmission demand forecasts are shown in Figure 10-6, Table 10-8, and Table 10-9.

Figure 10-6: Cromwell GXP demand forecast

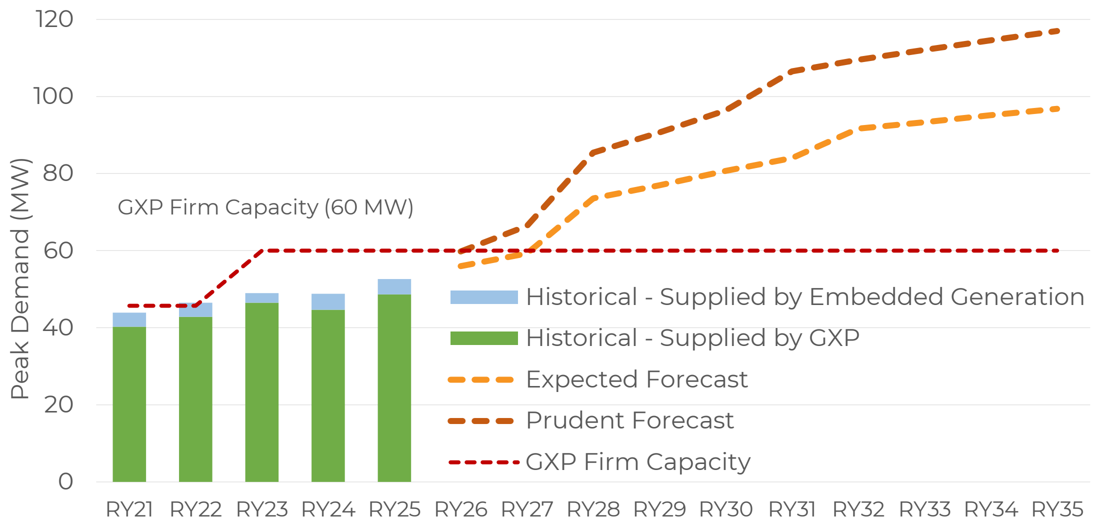


Table 10-8: Cromwell subtransmission demand forecast

Sub-transmission	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	**2024**	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Upper Clutha	Z1	43	N-1	30.5	34.5	35.3	**37.5**	40.1	42.5	56.2	58.9	62.1	64.7	71.9	73.0	74.6	76.1	77.9	Winter
		34	N-1	25.0	27.8	30.6	**29.7**	31.0	31.9	44.6	46.5	48.3	50.1	56.8	57.9	59.5	61.1	63.0	Summer

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

Table 10-9: Cromwell zone substation demand forecast

Zone substation	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Camp Hill	Z2	7.5	N	5.5	5.7	5.8	6.2	6.3	6.7	7.1	7.3	7.5	7.8	8.0	8.1	6.3	6.3	6.3	Summer
Cardrona	Z3	24	N	3.7	3.9	5.0	4.8	5.8	6.8	7.2	7.9	9.4	10.0	10.3	10.6	10.8	10.9	11.1	Winter
Cromwell	Z2	24	N-1	13.8	14.4	14.0	14.9	15.5	16.5	17.5	18.2	18.8	19.4	19.9	20.4	21.1	21.9	22.6	Winter
Lindis Crossing	Z3	10	N	6.6	7.0	8.5	8.4	9.5	9.5	9.1	9.1	9.2	9.2	9.2	9.3	9.3	9.4	9.4	Summer
Queensberry	Z3	4	N	3.4	3.8	2.8	2.9	3.0	3.2	3.2	3.3	3.3	3.3	3.4	3.4	2.2	2.2	2.1	Summer
Wānaka	Z1	23.8	N-1	25.0	27.2	25.5	26.9	27.5	28.3	21.4	22.6	22.8	24.4	26.0	26.5	26.4	26.5	26.5	Winter
Riverbank	Z3	24	N							8.6	9.2	10.5	10.8	11.1	11.3	12.2	12.8	13.3	New substation
Luggate		24	N													3.2	3.4	3.6	New substation

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

10.6.2.Network gaps

Key gaps between capacity and forecast demand for the Cromwell GXP are shown in Table 10-10.

Table 10-10: Cromwell GXP network gaps

Area	Constraint	Status
Cromwell GXP	The 220 kV Clyde-Cromwell-Twizel circuit supplies the GXP's two 3-winding transformers. There is no 220 kV bus. The 110 kV side supplies the Franklin GXP through the CML-FKN 1 transmission line. The 33 kV side supplies the Cromwell area. The 33 kV firm capacity is 58 MVA (summer/winter), limited by the 33 kV cable between the GXP transformers and the 33 kV outdoor bus Cromwell demand rose by 5 MW last year and is projected to increase beyond the 10-year AMP period. Additional capacity is required from the middle of the AMP period.	As a tactical solution before the 2026, Transpower and Aurora Energy have agreed to install a special protection scheme (SPS) in the Cromwell GXP transformers to allow the load to be above the firm capacity. Section 10.6.3 describes supply to future capacity needs.
Lindis Crossing and Queensberry Zone Substations	Both zone substations supply the load of Queensberry, Tarras, and Lindis Crossing. They are N-security level substations and provide backup to each other. We expect developments in the area will increase demand beyond the capacity of both substations.	We plan to build a new substation with a higher capacity transformer (and space for a future second transformer) and decommission the existing Queensberry zone substation in the short term. In the same period, we plan to strengthen the distribution feeders between substations to increase transfer capability. In the latter part of the AMP period, we plan to install a second transformer at Lindis Crossing when the load continues to grow. We plan to do the same with the new substation, but this is outside the 10-year plan.

Area	Constraint	Status
Wānaka Zone Substation	The forecast indicates that the load will be above the firm capacity and will continue to increase beyond the security of supply due to significant growth in the area.	Aurora Energy completed a load transfer project last year to provide the capability to transfer >1.5 MVA between Wānaka and Camp Hill. To offload Wānaka zone substation, Aurora Energy is installing a 24 MVA zone transformer at Riverbank switching station. This work is planned to be completed by RY27. In the long term, we plan to install a second 24 MVA transformer at Riverbank when the load grows beyond the security level.
Upper Clutha 66 kV Subtransmission circuit	The two Upper Clutha (UC) circuits take supply from the Cromwell 33 kV GXP through Aurora's 33/66 kV autotransformers rated at 36/30 MVA (winter/summer) The winter rating is limited by line losses and voltage constraints to 33 MVA. This is the maximum load where the voltage is within the regulatory limits when one circuit is out of service. The summer rating is limited to 29 MVA by the line losses when one circuit is out of service.	We have recently completed the installation of a new autotransformer of a higher rating and parallelling the existing autotransformers, which increases the subtransmission capacity to 43/36 MVA (winter/summer). In 2023, a special protection scheme (SPS) was commissioned to allow load above the firm capacity (for both winter and summer). Aurora Energy will review the use of the SPS when the load is forecast to be above the firm capacity. Aurora Energy has been employing non-network capacity support to augment the capacity constraint during peak demand periods. This is part of the CPP-approved Upper Clutha DER solution. Section 10.6.3 describes supply to future capacity needs.
Camp Hill Zone Substation	This is an N-security level zone substation. The forecast indicates that by middle of the AMP period, demand will be above the capacity of the transformer.	We plan to install transformer fans in RY27, to increase transformer capacity to 10 MVA In 2024, we installed and commissioned a 2 MVA generator to be utilised for emergency situations such as the loss of the single subtransmission or transformer. In 2023, Aurora Energy completed the load transfer project to provide capability to transfer >1.5 MVA between Wānaka and Camp Hill. Further, we plan to construct a new substation in the Luggate area in the latter part of the AMP period to cater for load growth, reduce the Camp Hill load, and rationalise the long run of distribution feeders between Camp Hill, Queensberry and Wānaka to improve reliability.

10.6.3.Upper Clutha region capacity

As **Table 10-2** shows, this year's peak demand at Cromwell GXP was 5 MW more than last year's, against a longer-term backdrop of 20 MW of growth in demand over the past decade.

In addition, the Upper Clutha region – which accounts for 80% of the load at Cromwell GXP – is experiencing exceptional growth. In the past four years, this region has seen 7 MW of growth, at an average annual increase of 2 MW. And our forecast indicates that this growth will continue beyond the 10-year planning period.

The Cromwell GXP 10-year demand forecast (shown in **Figure 10-9**) indicates that demand will be above the GXP firm capacity in 2027. The forecast incorporates various factors including known point loads, transport electrification, carbon fuel-to-electric (thermal) conversions, population growth, tourism, economic activity, DG penetration (EV, solar, solar-battery), and seasonal variations in climate and population due to tourists. These factors are all driving unprecedented growth in the Upper Clutha region.

Aurora Energy, Transpower, Queenstown Lakes District Council, and other stakeholders have extended the demand forecast to the year 2050 with minimum, likely, and prudent scenarios (see **Figure 10-7** and **Figure 10-8**). The demand forecast implies that growth will continue to 2050.

Any investment to cater for capacity, security and reliability must take into account future growth (beyond the 10-year horizon) but must also reflect the impact on consumers across the region. We have taken into account staged development on each option. With Cromwell GXP supplying Frankton GXP though the 110 kV transmission line, options must take into account the fact that investment in Cromwell GXP will impact Frankton GXP. Building on this forecast, Transpower, in collaboration with Aurora Energy, produced a long list of options to support the forecast demand growth from the GXP and transmission perspectives.

Aurora Energy has created minimum viable subtransmission and distribution network options to efficiently deliver electricity from the GXP to meet consumers' electricity supply requirements.

Shortlisted options are:

- New 66 kV line from Cromwell GXP to Upper Clutha route 1
- New 66kV line from Cromwell GXP to Upper Clutha route 2
- New capacity injection

There is a level of uncertainty around the projected demand, such as the pace and impact of electrification (transport, thermal and DG), the timing of large developments, and the changing energy needs of consumers. **Table 10-10** presents tactical solutions to mitigate short-to-medium term challenges, but the long-term solutions described above will require collaboration between local council, the community, Aurora Energy, and Transpower.

Figure 10-7: Upper Clutha winter peak demand forecast to 2050

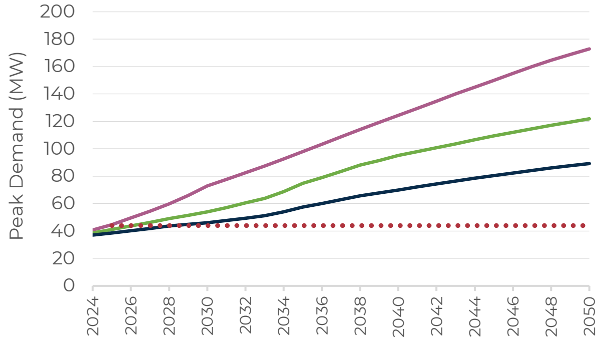
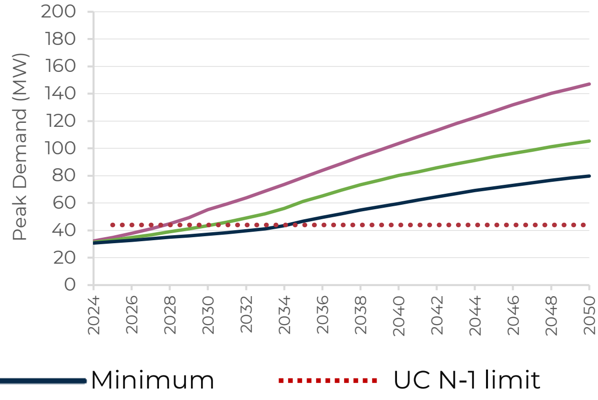


Figure 10-8: Upper Clutha summer peak demand forecast to 2050



10.6.4. Clyde demand

Clyde GXP subtransmission and zone substation demand forecasts are shown in **Figure 10-9**, **Table 10-11**, and **Table 10-12**.

Figure 10-9: Clyde GXP demand forecast

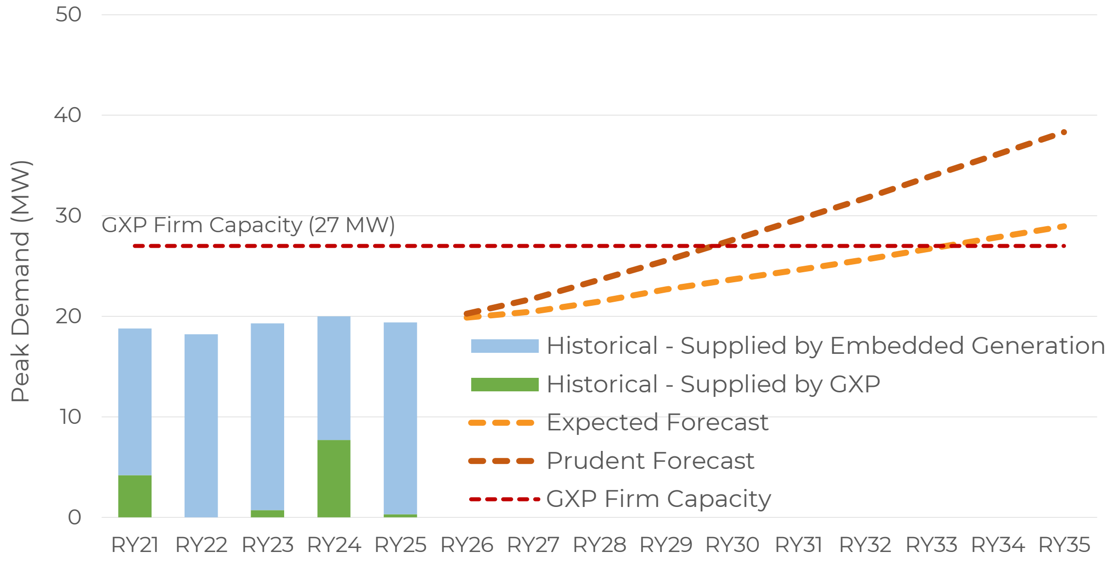


Table 10-11: Clyde subtransmission demand forecast

Sub-transmission	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Alexandra–Omakau	Z1	4.8	N	4.0	4.2	4.0	3.9	4.1	4.3	4.7	5.0	5.3	5.6	5.9	6.3	6.6	6.9	7.2	Summer
Roxburgh–Alexandra	Z1	16	N-1	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	Winter
Alexandra–Clyde	Z2	13	N-1	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	Winter

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

Table 10-12: Clyde zone substation demand forecast

Zone substation	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Alexandra	Z2	15	N-1 Switched	10.8	11.5	11.1	11.3	11.6	12.0	12.3	12.6	13.0	13.3	13.7	14.0	14.3	14.5	14.8	Winter
Dunstan	Z3	24	N	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	New substation
Clyde/Earnscleugh	Z3	4.8	N	3.9	4.1	4.2	4.4	4.4	4.7	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Summer
Ettrick	Z3	3.6	N	1.9	2.2	2.0	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	Autumn
Lauder Flat	Z3	3	N	1.0	1.2	1.0	1.0	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.5	1.6	Summer
Omakau	Z3	7.5	N	3.4	3.2	3.2	2.9	3.0	3.3	3.5	3.8	4.1	4.3	4.6	4.9	5.1	5.4	5.7	Summer
Roxburgh	Z2	5	N	2.0	1.7	2.1	2.3	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.1	3.2	3.4	3.5	Spring
Earnscleugh		2	N																Backup substation

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

10.6.5. Network gaps

Key gaps between capacity and forecast demand for the Clyde GXP are shown in Table 10-13.

Table 10-13: Clyde GXP network gaps

Area	Constraint	Status
Clyde GXP	No constraint in the 10-year AMP period. The GXP load is reduced by the large amount of generation capacity (32 MW). The embedded generation supplied most of last year's peak demand.	No action required at this stage.
Alexandra–Omakau Subtransmission	The subtransmission is a single circuit that runs 24 km with small size conductors. This thermal constraint limits the capacity toward the Omakau and Lauder Flat Substations. The demand forecast indicates continued growth in the region.	To address the thermal constraint, we plan to replace the small size conductors in the first part of the subtransmission line in the medium term.
Clyde–Alexandra and Roxburgh–Alexandra Subtransmission	The two subtransmission circuits are constrained by generation.	No additional generation can be added without an upgrade to the subtransmission. We will work with generation proponents to upgrade the network if required.
Dunstan Substation	Dunstan Substation is planned as the replacement for the Clyde/Earnscleugh Substation.	Stage 2 of the substation development is planned to be completed in RY27. After this, the Clyde/Earnscleugh distribution network will be transferred to Dunstan Substation. Once this is complete, the Clyde/Earnscleugh and Earnscleugh Substations will be decommissioned.

Area	Constraint	Status
Omakau Substation and Lauder Flat	The new Omakau Zone Substation with higher capacity is planned to be completed in RY25. The project includes installation of a 2 MVA generator to provide emergency supply during a loss of the single subtransmission or the single transformer. Both Omakau and Lauder Flat Substations are at N security level and load is growing in their network areas. Omakau can provide backup to Lauder Flat; however, Lauder Flat cannot provide backup to Omakau.	We have several planned projects for the Omakau and Lauder Flat Substations in the 10-year plan. • **Transfer load from Omakau to Alexandra:** this project is to offload Omakau Substation and increase transfer capacity between the substations. • **Link between Omakau and Alexandra:** this project is to increase transfer capacity between substations at Ida valley. • **Lauder Flat Security Upgrade Stage 1 & 2:** this project will supply Lauder Flat from Omakau substation with two feeders using the upgraded existing lines.
Ettrick substation	Ettrick Substation is at N security level and is planned to be renewed in the middle of the AMP period. The distribution network is supplied by a single feeder with limited transfer capacity.	In 2023, we completed a backfeed project between Ettrick Substation from Roxburgh. However, this is limited to the capacity of Ettrick Substation. In the latter part of the AMP period, we plan to rebuild the substation and increase capacity, reconfigure the distribution network to improve reliability, and increase transfer capacity to Roxburgh Substation.

10.6.6. Sub-network development investment

The major projects resulting from network gaps identified are shown in Table 10-14.

Table 10-14: Major projects for the Central Otago & Wānaka sub-network

GXP	Major Projects	From	To	Capex ($m)
Cromwell	**Riverbank Zone Substation (capacity event reopener)** Work is in progress to install a 24 MVA transformer at the Riverbank switching station to offload Wānaka Substation.	2025	2027	3.8
	New Queensberry Substation We plan to build a new substation with higher capacity and decommission the existing substation.	2025	2028	8.5
	Camp Hill Transformer Fans To increase transformer capacity, we will install fans to uprate the transformer from 7.5 MVA to 10 MVA.	2027	2027	0.3
	New Luggate Substation We plan to construct a new substation in the Luggate area in the latter part of the AMP period to cater for load growth and reduce the Camp Hill and Queensberry Substation loads.	2029	2031	7.5
	Cardrona to Riverbank 66 kV Line A new Cardrona to Riverbank 66 kV line will be constructed to increase security of Cardrona Substation.	2033	2035	12
	Lindis Crossing Capacity Upgrade Stage 1 We will install a second transformer and extend the 11 kV switchgear to cater for load growth, allow additional 11 kV feeders into the Bendigo area and increase transfer capacity to Queensberry Substation, which has a single transformer.	2033	2034	4.7
Clyde	**Dunstan Substation Stage 2** Stage 2 development includes construction of the 11 kV switchgear building and installation of the switchgear.	2026	2027	2.2
	Alexandra to Omakau Subtransmission Stage 1 Replace the small conductors in the first half of the subtransmission line to increase capacity.	2028	2030	3.3

GXP	Major Projects	From	To	Capex ($m)
	Ettrick Substation Upgrade Upgrade the substation capacity with a 7.5 MVA transformer, install indoor switchgear, and create a mobile substation bay.	2031	2033	6.1

The distribution projects to be completed for the Central Otago & Wānaka Sub-network are shown in Table 10-15.

Table 10-15: Distribution projects for the Central Otago & Wānaka Sub-network

GXP	Distribution Projects	From	To	Capex ($m)
Cromwell	**New Cromwell 838 Feeder Stage 2 & 3** This project involves reconfiguring the Cromwell distribution network to increase security level and reliability.	2026	2026	0.9
	Offloading of Lindis Crossing Feeder LC2086 The load on this feeder is reaching its capacity. This project is to transfer some load to the Cromwell Substation feeder (CM833) and also offload Lindis Crossing Substation.	2026	2026	0.05
	Cromwell Feeder (CM831) Cable Replacement Stage 1 & 2 Cromwell feeder CM831 capacity is constrained by the small 95PILC cable. This project will replace said cable with a higher capacity cable and improve network operation.	2026	2027	0.5
	New Cromwell Feeder (CM828) Demand is growing in the Cromwell Substation network area and there is limited offloading capacity between its feeders. This project is to create a new feeder, offload CM832, and increase network operational transfer capability to CM823 and CM831.	2027	2028	1.2
	Riverbank 11 kV Feeders Stage 1 (capacity event reopener) This project focuses on the distribution component of Riverbank Substation. Reconfigure some of the Wānaka feeders to become feeders of Riverbank Substation. The reconfigured network will have interconnection between the substations at Wānaka and Riverbank.	2027	2027	1.2
	Queensberry (QB2424) Conductor Upgrade Replace the existing conductor to improve capacity, voltage and transfer capability between the substations at Queensberry and Lindis Crossing.	2027	2027	1
	Queensberry (QB2423) Conductor Upgrade Stage 1-3 Replace the existing conductor to increase capacity and transfer capacity to Cromwell Substation.	2027	2030	2
	New Queensberry Substation Feeders This project focuses on the distribution component of the new Queensberry Substation. The project is to install new cables and connect them to the existing overhead Queensberry feeders.	2028	2029	0.8
	Burn Cottage Road Upgrade (CM832) This project is to improve reliability of CM832.	2029	2029	0.4
	Camp Hill Substation Backup Replace the existing conductor between Camp Hill and the new Riverbank Substation to increase transfer capacity.	2030	2032	1.4
	Camp Hill to Luggate Network Reinforcement Replace the existing conductor between Camp Hill and the proposed new Luggate Substation to increase transfer capability.	2034	2035	4.1
	Cromwell (CM832) Feeder reinforcement Reconfigure the Cromwell distribution network to increase security and reliability.	2030	2031	1.6

GXP	Distribution Projects	From	To	Capex ($m)
	Luggate Distribution Network This project focuses on the distribution component of the new Luggate Substation. The distribution network in the area will be reconfigured to rationalise the long run of distribution feeders between the Camp Hill, Queensberry, and Wānaka Substations.	2032	2033	5.5
Clyde	**Alexandra New Feeder** Install a new feeder cable to offload an existing feeder, thereby increasing transfer capacity between the Alexandra and Clyde/Earnscleugh Substations. The cable has been installed and will be terminated to the new 11 kV CB after completion of the Alexandra 11 kV switchgear replacement.	2024	2025	0.5
	Reconfigure Clyde/Earnscleugh Distribution Network This project focuses on the distribution component of the new Dunstan Substation. It involves transferring and reconfiguring the distribution network to Dunstan Substation. Upon completion, we will decommission the Clyde/Earnscleugh and Earnscleugh Substations.	2027	2028	3.2
	Lauder Flat Security Upgrade Stage 1 & 2 Supply Lauder Flat from Omakau Substation with two feeders using upgraded existing lines.	2028	2032	2.8
	Transfer Load from Omakau to Alexandra Substation Increase transfer capacity between Omakau and Alexandra and offload Omakau.	2027	2029	4.4
	Link between Omakau and Alexandra Substations A project to provide interconnection between the Omakau and Alexandra Substations at Ida valley.	2032	2034	2.9
	Ettrick Network Reconfiguration Reconfigure the network to increase security and reliability and transfer capacity to Roxburgh.	2033	2035	3.5

10.7. QUEENSTOWN SUB-NETWORK INVESTMENT

10.7.1. Frankton demand

Frankton GXP subtransmission and zone substation demand forecasts are shown in **Figure 10-10**, **Table 10-16**, and **Table 10-17**.

Figure 10-10: Frankton GXP demand forecast

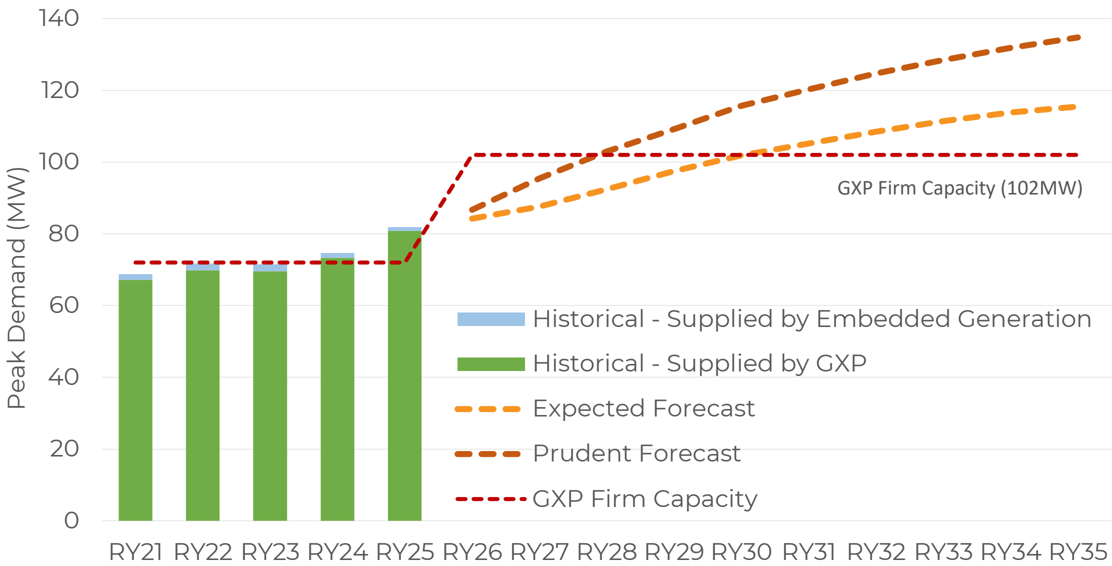


Table 10-16: Frankton Subtransmission

Sub-transmission	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Arrowtown Ring	Z1	26	N-1 Switched	17.5	17.9	17.8	18.6	18.7	19.0	19.7	20.4	20.9	21.3	21.7	22.1	22.4	22.7	22.8	Winter
Queenstown	Z1	36.8	N-1	29.4	30.9	31.5	32.5	33.5	35.0	36.5	38.2	39.8	41.0	42.2	43.1	44.0	44.4	44.7	Winter

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

Table 10-17: Frankton zone substations

Zone substation	Security class	Firm capacity MVA	Security level	Historical				Forecast											Peak Period
				2021	2022	2023	**2024**	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	
Arrowtown	Z2	10	N-1 Switched	9.4	9.7	9.6	**10.5**	10.8	11.2	11.6	12.1	12.5	9.6	9.8	10.1	10.3	0.0	0.0	Winter
Commonage	Z2	15	N-1 Switched	11.2	11.6	11.8	**12.3**	12.4	12.6	12.8	13.0	13.2	13.4	13.7	13.9	14.1	14.3	14.5	Winter
Coronet Peak	N/A	6	N	5.4	5.1	5.2	**5.5**	5.5	5.5	5.5	5.5	5.5	0.0	0.0	0.0	0.0	0.0	0.0	Winter
Dalefield	Z3	3.6	N	1.7	1.7	1.7	**2.0**	2.0	2.1	2.7	3.5	3.7	0.0	0.0	0.0	0.0	0.0	0.0	Winter
Fernhill	Z2	10	N-1 Switched	5.9	6.3	6.5	**6.8**	7.3	7.8	8.4	8.6	9.2	9.7	10.2	10.5	10.7	10.8	10.8	Winter
Frankton	Z1	24	N-1	17.1	18.0	18.2	**19.5**	20.3	21.2	22.7	24.1	25.6	24.6	25.5	26.4	27.1	27.8	28.5	Winter
Jacks Point	Z3	10	N												4.9	4.9	5.0	5.0	New substation
Queenstown	Z2	20	N-1 Switched	12.2	12.4	12.7	**12.6**	12.9	13.6	14.2	15.2	16.1	16.6	17.1	17.5	17.9	18.0	18.1	Winter
Remarkables	N/A	3.6	N	2.3	2.3	2.3	**2.3**	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	Winter
Malaghans	Z1	2.4	N-1										12.4	12.8	13.2	13.5	13.7	13.9	New substation
Whitechapel	Z1	2.4	N-1														10.4	10.4	New substation

Historical demand | Forecast demand | **N security level:** If forecast demand >70% of stated capacity; *or* **N-1 security level:** If forecast demand >110% of stated capacity

10.7.2.Network gaps

Key gaps between capacity and forecast demand for the Frankton GXP are shown in Table **10-18**.

Table 10-18: Frankton GXP network gaps

Area	Constraint	Status
Frankton GXP	Frankton GXP (FKN) is supplied by the 110 kV CML–FKN line from Cromwell GXP (CML). There is no 110 kV bus at Frankton. The first constraint is that the 110 kV transmission line is limited by line loading at 77 MW. The next constraint is the GXP capacity, which is limited by voltage stability to 84 MVA. The forecast indicates that in the next two to three years the load will be above the GXP firm capacity limit. This year, demand at Frankton GXP increased by 7 MW. This is projected to increase further beyond the 10-year AMP. *Note:* Aurora Energy shares this GXP with another EDB.	In 2023, a special protection scheme (SPS) was commissioned to allow the load (for both winter and summer) to be above the firm capacity of the 110 kV transmission line. Tactical solutions to increase capacity are as follows: • Transpower is progressing with the replacement of the existing GXP transformers with 120 MVA transformers. This is aimed to be completed before winter 2025. • Aurora Energy and PowerNet have engaged Transpower to conduct a study toward increasing transmission line capacity. Implementation of the thermal upgrade would increase the line capacity to 100 MVA and is planned for RY27. Section 10.7.3 describes how we plan to ensure supply meets future capacity needs.
Queenstown Subtransmission	The forecast shows that the peak demand will be above the firm capacity from the middle of the AMP period.	We plan to upgrade the limiting sections of circuits 1 & 2 to increase capacity.

Area	Constraint	Status
Arrowtown Subtransmission	With the planned developments (Dalefield and Arrowtown, described below), capacity of a part of the circuit will be constrained under certain network operational configurations.	We plan to upgrade the limiting section of the subtransmission circuit.
Dalefield and Coronet Peak Substation	The Dalefield and Arrowtown Substations supply Dalefield, Speargrass, Arrowtown, Arthurs Point, and Lake Hayes. Coronet Peak Substation supplies the ski field. There is significant growth in the area, which will exceed the capacity of both Dalefield Substation (N security) and Arrowtown Substation (N-1 security) in the planning period. In the medium term, the forecast indicates that demand will be above the capacity of these substations.	We will construct a new substation (Malaghans) with a firm capacity of 24 MVA to cater for the expected growth. The plan is for the new substation to supply Dalefield and Coronet Peak ski field. The Dalefield and Coronet Peak Substations will then be decommissioned. Dalefield areas supplied by the Frankton Substation will be transferred to the new substation. Further, we are planning to transfer some load from the Arrowtown Substation to the new substation. This transfer will allow deferral of the Arrowtown capacity upgrade to the latter part of the AMP period. The distribution network of the area will be reconfigured to increase security and reliability.
Arrowtown Substation	As above.	The plan for the Arrowtown Substation is to construct a new substation (Whitechapel) with a firm capacity of 24 MVA in the latter part of the 10-year plan.
Queenstown, Fernhill, and Commonage Substations	The forecast indicates that demand will grow near the firm capacity of the substations at the end of the 10-year planning horizon.	We are investigating options to rationalise the load on the substations at Queenstown, Fernhill, and Commonage. The initial plan is to transfer the Glenorchy load from Queenstown to Fernhill to cater for the large development in Queenstown.
Remarkables Substation	This is an N security level substation. Growth in the area would require additional capacity.	We plan to upgrade the existing substation to increase its capacity.
Frankton Substation	Localised growth such as in the Frankton Southern Corridor and Ladies Miles areas are pushing the demand above the firm capacity of Frankton Substation	We aim to complete the project to replace the existing 15 MVA transformer with a 24 MVA transformer in RY25. This will increase the firm capacity to 24 MVA. We plan to build two new substations (Jacks Point and Whakatipu) to cater for the increasing load growth and offload Frankton Substation. We have also planned to reconfigure the distribution network to increase reliability and operability.

10.7.3. Queenstown region capacity

Queenstown region is experiencing unprecedented growth. In the last ten years, Frankton GXP has experienced an average 2.8 MW load increase per year, with the last three years averaging 6.5% demand growth. The 2025 winter peak load reached 82 MW, up by 7 MW from the previous year, and the demand forecast indicates continuing growth in the region beyond the 10-year horizon.

The Frankton GXP demand forecast shows that demand will be above the firm capacity by 2029. The forecast incorporates various factors including known point loads, transport electrification, carbon fuel-to-electric (thermal) conversions, population growth, tourism, economic activity, DG penetration (EV, solar, solar-battery), and seasonal variations in climate and population.

Aurora Energy, Transpower, Queenstown Lakes District Council, and other stakeholders have extended the demand forecast to the year 2050 with minimum, likely, and prudent scenarios (see Figure 10-11 and Figure 10-12). The demand forecast implies that the demand growth will continue to 2050.

Any investment aimed at increasing capacity must consider future growth beyond a 10-year horizon. Additionally, it is crucial to assess the impact on consumers across the entire region.

Building on this forecast, Transpower, in collaboration with Aurora Energy, produced a long list of options to support the forecast demand growth from the GXP and transmission perspectives.

Aurora Energy has created subtransmission and distribution network options to efficiently deliver electricity from the national grid to cater for consumers' electricity supply requirements.

High-level system studies and cost estimates are currently being prepared for each of the options, which will be assessed to create a shortlist. We will then conduct more detailed system studies and cost analysis on the shortlisted options.

There is a level of uncertainty around the projected demand, such as the pace and impact of electrification (transport, thermal and DG), the timing of large developments, and the changing energy needs of consumers. We have created a minimum viable plan to address known growth-related constraints, and the options take into account staged development. In **Table 10-18**, we discussed tactical solutions to mitigate short-to-medium term challenges up to 2029, but the long-term solutions described above will require involvement between local council, the community, Aurora Energy, and Transpower.

Figure 10-11: Whakatipu winter peak demand forecast to 2050

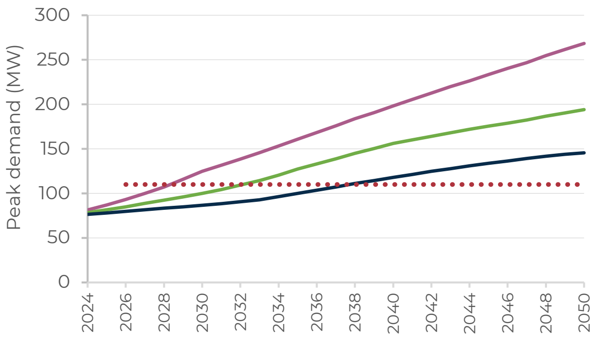
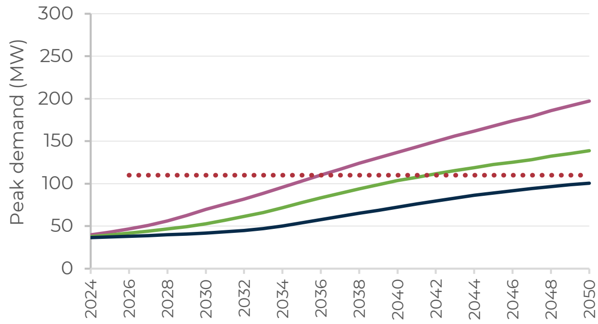


Figure 10-12: Whakatipu summer peak demand forecast to 2050



Maximum Midpoint Minimum FKN N-1 limit

10.7.4. Sub-network development investment

The major projects resulting from network gaps identified are shown in **Table 10-19**.

Table 10-19: Major projects for the Queenstown sub-network

Major Projects	From	To	Capex ($m)
Frankton Transformer Replacement (capacity event reopener) Work is underway to install a new 24 MVA transformer to replace the 15 MVA transformer, to increase firm capacity. We plan to complete this project in RY25.	2024	2025	1.6
Malaghans Substation Construct a new substation with an indoor 33 kV and 11 kV switchgear building and two outdoor 24 MVA transformers. The new substation will replace the Dalefield and Coronet Peak Substations.	2025	2028	11.2
New Remarkables Substation Rebuild the substation with a higher capacity transformer and additional distribution feeders.	2029	2030	6
Queenstown Subtransmission Capacity Upgrade The limiting sections of Queenstown subtransmission circuits 1 & 2 will be replaced to increase capacity.	2030	2031	2.5
Jacks Point Substation A new substation to cater for growth in Frankton South.	2030	2031	5

Major Projects	From	To	Capex ($m)
Whitechapel Substation This substation will replace the Arrowtown Substation. The new substation will have an indoor 33 kV and 11 kV switchgear building and two outdoor 24 MVA transformers.	2031	2033	11
Malaghans Subtransmission The existing 33 kV subtransmission Ferret conductor constrains the capacity of the subtransmission. This project will replace the existing 33 kV conductor as well as the 11 kV underbuilt with higher capacity conductor.	2031	2032	4.5
Lake Hayes Subtransmission Cable Upgrade The limiting section of the Arrowtown subtransmission circuit will be replaced to increase capacity.	2034	2035	1.2
New Whakatipu Substation A new substation to offload the Frankton Substation.	2034	2035	7

The distribution projects to be completed for the Queenstown sub-network are shown in Table 10-20.

Table 10-20: Distribution projects for the Queenstown sub-network

Distribution Projects	From	To	Capex ($m)
Fernhill Feeder Reconfiguration One of the Fernhill feeders carries most of the load and is reaching its maximum capacity. This project is to transfer some of its load to another feeder.	2026	2026	1.2
Frankton Southern Corridor Cable Growing load at Jacks Point will impact voltage during peak periods. This project provides an additional injection to the area to cater for the increasing load and mitigate voltage issues.	2027	2027	1
New Commonage Feeder The two existing feeders at Commonage are highly loaded and are limited by the existing cable size. This project will divide the load of the feeders and provide transfer capacity.	2027	2027	2.2
Malaghans Substation Distribution Network This project is the distribution component of the Malaghans Substation. The project aims to reconfigure the existing distribution network and improve offloading options to increase reliability.	2028	2030	7.8
Queenstown Feeder Reconfiguration Stage 1 Load on the existing feeder that supplies Gorge Road – and also provides backup supply to Arthurs Point – is increasing. This project will resolve this constraint and increase transfer capacity.	2030	2031	0.8
Frankton Arm 11 kV Feeder The demand in the Kelvin Heights area is increasing and is currently supported by a single feeder from Frankton with no transfer capacity. This project aims to enhance the security level to align with Aurora Energy's security of supply guidelines.	2030	2031	1
Frankton Feeder Cable across Shotover Bridge The existing feeder to Lake Hayes is subject to high load and has limited offloading options. This project will resolve this constraint and also cater for future developments in the area such as Ladies Mile development.	2031	2032	1
Whitechapel Substation Distribution Network This project is the distribution component of the Whitechapel Substation. The project aims to reconfigure the existing distribution network and improve offloading options to increase reliability.	2033	2035	11.4

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MANAGING OUR ASSETS

CHAPTER 11
OUR NETWORK ASSETS

Our network assets are grouped into portfolios of similar asset types. This helps us manage them in a way that provides the best opportunity to enhance resilience and reliability, while minimising risk to both personnel and public safety, for the least cost.

11.1. OVERVIEW

Chapter 6 of this AMP describes the approach and strategies we apply to asset lifecycle management. In this chapter, we describe in more detail how we apply this approach to our assets and then summarise the resulting renewal and maintenance plans by asset fleet.

This section provides an overview of our network assets by portfolio and fleet. The age, condition, performance, and risk profiles are indicative of key considerations documented in more detail in our *Fleet Strategies* – a set of working documents that enable optimised and strategically aligned renewal and maintenance planning over the AMP period.

Points to note on the content in this chapter are as follows:

- All technical and quantity statistics are accurate as of 28 March 2025 (unless specified otherwise).
- Capex graphs reflect RY25 forecasts as at November 2024, but the RY25 forecasts in Schedule 11a reflect updated estimates prepared in February 2025, which take into account higher than expected levels of RY25 capex.
- Opex graphs reflect RY25 forecasts as at November 2024, but the RY25 forecasts in Schedule 11b reflect updated estimates prepared in February 2025. These updated forecasts take into account lower levels of RY25 opex resulting largely from the deferral of new network and technology based initiatives pending negotiation and execution of commercial arrangements.
- For explanations of modelling approaches, including our definitions of risk and asset health indices (AHI), see Chapter 5.
- For a list of major renewal projects, see Appendix H.

11.1.1. Asset portfolios

Aurora Energy owns and operates a substantial network of assets to supply electricity to 95,600 customers. We currently categorise our assets into seven asset portfolios, which are then further subdivided into 28 fleets according to their functionality, as shown in Table 11-1.

To achieve better oversight of our assets and align them to our team's structure, capabilities and experience, we have elected to diverge somewhat from the categorisation described in the Commerce Commission Information Disclosure.

Table 11-1: Our asset portfolios in relation to Information Disclosure categories

Portfolio	Fleet	Asset replacement and renewal information disclosure schedule
Support Structures	Poles, Crossarms	Included in 'Subtransmission' and 'Distribution and LV Lines'
Overhead Conductor	Subtransmission Conductor, Distribution Conductor, LV Conductor	Included in 'Subtransmission' and 'Distribution and LV Lines'
Underground Cables	Subtransmission Cables, Distribution Cables, LV Cables	Included in 'Subtransmission' and 'Distribution and LV Cables'
Zone Substations	Buildings & Grounds, Transformers, Switchgear, Ancillary Equipment, Mobile Substations	Included in 'Zone Substations'
Distribution Switchgear	HV Ground-mounted Switchgear, Reclosers, ABS, Pole-mounted Fuses – Links, LV Enclosures, Distribution Ancillary Equipment	Included in 'Distribution Switchgear' (see also LV enclosures in 'Distribution and LV Cables' and ancillary distribution substation assets in 'Distribution Substations and Transformers')

Portfolio	Fleet	Asset replacement and renewal information disclosure schedule
Distribution Transformers	Auto Transformers, Distribution Transformers, Mobile Transformers, Voltage Regulators	Included in 'Distribution Substations and Transformers' (see also Mobile Generators in 'Other Network Assets')
Secondary Systems	Protection, DC Systems, RTUs/Metering	Included in 'Secondary Systems'
	Network Communications	Included in 'Secondary Systems'

The following sections discuss our approach to portfolio and fleet management at two levels of detail. For more significant portfolios and fleets, from a complexity and management perspective, we provide more detail in the relevant fleet-specific sections.

11.1.2. Fleet strategies

Our fleet strategies are designed as 'living documents' and are continually updated to provide real-time dashboard views of the key information about each fleet. Because the fleet strategy documents are changing over time, we employ a system of versioning to save 'snapshots' of the documents every 12 months, aligned to our AMP preparation. Fleet strategies capture the following information:

- Context and alignment with asset management objectives
- Dashboard of key data insights
- Documentation of all plausible failure modes and assessment of their impact against our Risk Management Standard
- Risk and opportunity
- AHI model – informing our forecasts for renewals
- Maintenance strategy – what we need to do and how often we need to do it
- Renewal strategy – how we prioritise renewals
- Spares strategy – which asset types and how many we hold in our stores
- Future state fleet strategies – what more we can do to enable realisation of each asset management objective
- Capex plan
- Opex plan
- Improvement plan

The completeness and maturity of our fleet strategies varies. We are currently undertaking a review, including a maturity assessment of each fleet strategy. The outcome will be a detailed and complete improvement plan for each fleet strategy. This work is being undertaken with input from an independent asset management consultant.

11.1.3. Our objectives

As outlined in detail in Part B, we have set out our asset management objectives, guided by our business strategy. Table 11-2 outlines some key portfolio-level objectives relating to each asset management objective (**bold**). Each of our fleet strategy documents captures the line of sight from asset management objectives to fleet-specific intent and seeks to use the framework to identify and rectify any gaps.

Table 11-2: Key asset management objectives – Portfolio management

Asset Management Objective	Key Asset Management Objectives Portfolio Objectives
Safety first	**Asset Management activities support meeting our health and safety compliance and community obligations** We ensure our assets conform to applicable regulatory standards and codes of practice **We take all reasonable practical steps to manage safety risks** We understand and have a plan to address data quality constraints We have a clear understanding of asset health, informed by age/condition We investigate asset failures and use insights to put improvements in place to prevent re-occurrence We carry out regular inspections on our assets **Safety of community and personnel is never compromised** We understand the consequence of failure of our assets and manage them appropriately We ensure safety-related signage is applied and maintained in accordance with clearly-defined standards We ensure phase identification is accurate and appropriate We run campaigns to promote public awareness of the dangers associated with our safety-critical assets **Safety is prioritised when operating and managing our assets** We are conservative in our approach to ensuring known or emerging hazards are appropriately removed or mitigated We deploy Do Not Operate (DNO) in the case of known risks that cannot otherwise be managed We notify contractors of systemic issues We provide an avenue for reporting defected assets, to enable time-appropriate intervention **Safety criticality is factored into our investment decision-making** We employ safety-in-design considerations in our design processes to ensure assets are appropriately configured and located We prioritise renewals based on assessed risk We identify, forecast, analyse and track safety risks and implement and monitor the effectiveness of controls

Asset Management Objective	Key Asset Management Objectives Portfolio Objectives
Reliability to defined levels	**Reliability improvements are achieved through refined management of assets** Our outages caused by condition-driven failures are trending downward We take steps to understand asset failure causes and failure rates and to identify any failure trends We utilise network performance information to develop insights into our inspection and maintenance strategies We identify and manage accordingly any assets that may present a significant reliability impact upon failure We review our protection schemes to ensure the impact of outage events is reduced to manageable levels **We manage planned outages to reduce their impact on consumers** We take into account the potential impact on consumers when we plan maintenance and renewals, to minimise disruption We carry out proactive replacement as appropriate to limit reactive repair work and consequent disruption to consumers
Affordability through cost management	**We aim to ensure we do the right work, at the right time, for the right cost** We adapt our inspection and intervention strategies according to our corporate risk standard We focus on the value we deliver to consumers by identifying opportunities to package work in a way that drives efficiencies and cost savings We have access to a comprehensive set of unit rates We look for ways to get better condition assessment data so we can continuously improve our asset health, criticality, and risk models for more cost-effective forecasting and decision-making **We strive to ensure assets fulfil their optimum life expectancy through preventive and corrective maintenance and whole-of-life considerations** Our renewal planned expenditure aims to achieve optimal life, informed by the best information we have, with a supporting continual improvement plan to optimise the data and frameworks deployed to inform determination of health We carry out quality assurance of physical work on our network **We have a fit for purpose cost estimation process to provide accurate costing, forecasting, and options analysis** We have established and continue to improve our cost estimation process and tools **We use alternative solutions to improve cost outcomes** We measure asset performance and investigate new and alternative materials and manufacturers to ensure value in our investments, reduce management costs, and increase life expectancies
Responsiveness to a changing landscape	**We respond to changes in customer preferences and demand** We investigate network synergies for optimal solutions We collaborate with the Planning team to identify changes in demand early and understand our options for accommodating those changes, including considering non-network solutions We adapt our strategy to understand if assets can work harder in response to demand, and we measure the impacts of such decisions

Asset Management Objective	Key Asset Management Objectives Portfolio Objectives
	Technological developments are monitored, and feasibility tested We investigate and implement new or alternative technologies to: - ultimately enable us to respond to change, including that driven by climate change - improve reliability and cost effectiveness when planning asset renewals - improve the quality of condition assessment data and the efficiency with which it is obtained - better understand loadings on network assets - obtain better fault information to facilitate analysis **Strategic scenarios are developed to support network evolution** We explore alternative network solutions when assets are identified for renewal **Asset data is defined and managed with fit-for-purpose ICT solutions** We continually update our asset data requirements to enable effective asset management decisions **Target 'least-regret' investments to create long-term flexibility, enabling greater customer choice and value** We consult with the wider business to take into account future needs
Sustainability by taking a long-term view	**We comply with relevant standards and codes of practice** We minimise negative environmental impact We explore OHUG as part of our reconductor options analysis We consider the long-term sustainability of our business in our investment decision-making **We evaluate the implications of the disposal and making-good processes in our whole of life considerations** We factor environmental criticality into our decision-making **Sustainability is considered as part of our materials and equipment approval process** We evaluate the implications of the disposal and making-good processes in our whole-of-life considerations We dispose of assets responsibly and reuse them where practical to benefit the community We apply good industry practice and reporting for management of hazardous substances, including oil and SF_6 We minimise spills and leaks of oil and SF_6 from all assets and ensure all leaks are fully contained We pursue opportunities to increase network resilience through management of seismic risk and uprating of assets where economically viable We maintain comprehensive, up-to-date, and readily accessible asset data – including for secondary and protection settings – in an effective and controlled asset information system We minimise interruptions and inconvenience to the public when undertaking asset repairs or renewals, and plan for consolidated works with other utilities We mitigate all non-compliant noise pollution in a timely manner

We also capture our maintenance objectives in our fleet strategy documents. As set forth in Table 11-3, our maintenance objectives are generally key enablers of our asset management objectives.

Table 11-3: Key maintenance objectives – Portfolio management

Asset Management objective	**Key Maintenance Objectives** Portfolio Objectives
Safety first	Our inspection programmes are designed to identify the onset of failure modes Our preventive maintenance activities are informed by inspection results, understanding of risk, failure modes, and supplier recommendations where applicable We carry out corrective maintenance informed by inspections, defects, or faults We identify safety risks to our workforce and the public in a timeframe appropriate to the risk We minimise vegetation-related safety and environmental risks We provide improved education around risks associated with vegetation near conductor
Reliability to defined levels	We consider planned outage reliability limits when planning outages for preventive maintenance We remedy defective or deteriorating components in an appropriate timeframe to minimise unplanned service interruptions We aim to reduce the risk of vegetation-related events damaging network equipment, to minimise the impact of vegetation on reliability performance We aim to reduce planned outages by targeting vegetation trimming and ensuring such work is aligned with other activities
Affordability through cost management	We minimise whole-of-life costs by undertaking corrective work based on well-informed opex/capex trade-offs We ensure economies of scale by undertaking multiple works in a coordinated manner We take steps to improve vegetation management cost efficiency and programme effectiveness We take steps to reduce the occurrence of vegetation-related faults and related expenditure We are expanding our feeder-based approach to inspection and testing to other network assets for greater efficiency and improved asset data We are increasing our understanding of failure causes with a view to better targeting preventive and corrective maintenance activities We identify systemic causes of failure to inform more effective maintenance and inspection activities We use technology to assist with vegetation management planning and improve efficiency
Responsiveness to a changing landscape	We use RCA (root cause analysis) outcomes to refine our inspection and maintenance activities We use wider industry learnings to refine inspection and maintenance activities
Sustainability by taking a long-term view	We carry out annual acoustic and thermal inspections in FENZ-designated fire-prohibited zones We have a plan to identify and address defects in fire-prohibited zones, ahead of season We identify and remediate environmental risks and issues before they become unacceptable to stakeholders We minimise landowner disruption as much as reasonably practicable We aim to clear backlogs and transition to a steady-state preventive maintenance programme

11.1.4. Asset information and data quality

As described in Section 6.4, quality asset data is central to robust evidence-based decision-making. We are continually improving our data and data quality as part of our asset management maturity journey.

Table 11-4 provides a high-level overview of primary data sources and our level of confidence in the data as per Schedule 12a in Appendix B. The reported data accuracy scale of 1 to 4 is in accordance with the scale defined by the Commerce Commission at https://comcom.govt.nz/.

Where we have judged that it would be of value to track our confidence in data as it is updated or verified, we have included fields for this purpose in the design of our asset management software solution, IBM Maximo, which will be the repository for our asset data. Data confidence will grow as we expand our inspection programme, continually update the programme to capture failure investigation learnings, and improve our systems for gathering and managing data.

In applying this framework, we have considered data from the perspectives of type, location, age, and condition, noting that some fleets have more established, more mature inspection regimes and thus type/location validation and condition data, whereas in other cases, age is used as the basis for determining AHI.

Table 11-4: Asset data sources and quality

Portfolio	Asset Fleet	Primary Data Source	Source Description	Condition Data Confidence Level[6]
Support structures	Poles	Maximo + S123 report	A direct connection to Maximo asset tables used to provide the asset-specific information that links the pole location to other assets.	3
	Crossarms	Maximo + S123 report	A direct connection to Maximo tables used to provide all asset information.	2
Overhead conductor	Subtransmission conductor	GIS + FME	A semi-automated export of GIS using Feature Manipulation Engine (FME) to group sections of conductor based on material. Used to provide the asset information.	2
	Distribution conductor	GIS + FME	A semi-automated export of GIS using FME to group sections of conductor based on material. Used to provide the asset information.	2
	LV conductor	GIS + FME	A semi-automated export of GIS using FME to group sections of conductor based on material. Used to provide the asset information.	2
Underground cables	Subtransmission cable	SubTrans UG Cable Asset Fleet Register	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	2
	Distribution cable	GIS	A direct connection to GIS used to provide all asset information.	2
	LV cable	GIS	A direct connection to GIS used to provide all asset information.	2

[6] Data accuracy levels 1–4 from comcom.govt.nz, where:
1 - Means that good quality data is not available for any of the assets in the category and estimates are likely to contain significant errors
2 - Good quality data is available for some assets but not for others and the data provided includes estimates of uncounted assets within the category
3 - Data is available for all assets but includes a level of estimation where there is understood to be some poor-quality data for some of the assets within the category
4 - Good quality data is available for all of the assets in the category

Portfolio	Asset Fleet	Primary Data Source	Source Description	Condition Data Confidence Level[6]
Zone substations	Buildings	Fleet Strategy Raw Data Table	A manual spreadsheet maintained by SME.	2
	Power transformers	Fleet Strategy Raw Data Table	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	3
	Indoor switchgear	Fleet Strategy Raw Data Table	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	2
	Outdoor switchgear	Fleet Strategy Raw Data Table	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	2
	Ancillary equipment	Fleet Strategy Raw Data Table	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	3
Distribution switchgear	Reclosers and sectionalisers	Recloser Asset Fleet Register	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	2
	Ground-mounted switchgear (other than RMU)	HVGM SWGR Asset Fleet Register	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	2
	Ground-mounted switchgear (RMU)	HVGM SWGR Asset Fleet Register	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	3
	Pole-mounted fuses	Maximo	A direct connection to Maximo used to provide all asset information.	2
	Pole-mounted switches	Fleet Strategy Raw Data Table	A copy of the updated ABS information provided to the data team. Interim solution to provide asset information while data is being loaded into GIS.	2
	LV enclosures	Maximo	A direct connection to Maximo used to provide all asset information.	3
	Ancillary distribution substation equipment	Maximo	A direct connection to Maximo used to provide all asset information.	3
Distribution transformers	Ground-mounted distribution transformers	Maximo	A direct connection to Maximo used to provide all asset information.	3
	Pole-mounted distribution transformers	Maximo	A direct connection to Maximo used to provide all asset information.	3
	Voltage regulators, auto-transformers	Voltage Regulator Asset Fleet Register	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	3
	Mobile distribution substations	Fleet Strategy Raw Data Table	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME.	3

Portfolio	Asset Fleet	Primary Data Source	Source Description	Condition Data Confidence Level[6]
Secondary systems	Remote terminal units (RTUs)	Fleet Strategy Raw Data Table	An export of the information found in Maximo. Contains the asset information.	3
	Protection	Fleet Strategy Raw Data Table	An export of the information found in Maximo. Contains the asset information.	3
	Batteries and DC supplies	Fleet Strategy Raw Data Table	An export of the information found in Maximo. Contains the asset information.	3
	Communication assets	Installation and commissioning data; Inspections and reports; Monitoring software	Manual spreadsheets and reports actively maintained by the SME, coupled with real-time performance tracking using Paessler PRTG software.	3
	Metering	Fleet Strategy Raw Data Table	An export of the information found in Maximo. Contains the asset information.	3

11.2. MAINTAINING OUR ASSETS

Our maintenance activities are divided into four categories of opex:

- Preventive maintenance
- Corrective maintenance
- Reactive maintenance
- Vegetation management

Section 6.5 provides an overview of our strategies for these maintenance activities, whereas this chapter provides more specific detail on our portfolio approaches.

Opex forecasts are informed by base-step-trend models. This involves establishing a base level of expenditure from historic information, to which we apply step changes to account for factors such as new inspection or maintenance requirements, as well as trends that account for ongoing factors such as network growth.

Chapter 15 discusses in detail the approach and inputs used to determine the opex forecasts, by category.

These forecasts exclude internal staff costs associated with managing the work undertaken by our service providers, as these costs are included in our System Operations and Network Support (SONS) portfolio.

11.2.1. Preventive maintenance

Preventive maintenance activities are predetermined activities that encompass inspection and maintenance. They can be *time-based* (meaning the activity is conducted on a regular cyclic schedule), or *duty-based* (meaning the activity is triggered following a predetermined number of operations).

In conjunction with the implementation of our IBM Maximo asset management software solution, we have undertaken a review of our preventive maintenance activities with a view to rationalising and aligning the timing of activities for greater efficiency. For a summary of our preventive maintenance activities by fleet, refer to Appendix G.

The base forecast for preventive maintenance is calculated by analysing the expenditure in the nominated *base year* (the last full year of data at the time of putting the forecasts together). As part of our continuous improvement work to better understand asset condition and respond to root cause fault information, we have made step changes in our preventive maintenance forecast. Key steps and trends incorporated into our preventive maintenance plan include:

- A reduction of $1.2 million in the DPP4 period associated with disestablishing our ABS inspection programme, which is now incorporated into the new overhead programme (introduced as a direct consequence of root cause fault analysis).
- Introduction of a routine overhead acoustic testing programme in targeted areas. We have been trialling the acoustic testing

methodology with good success in picking up cracked/damaged insulators and binding wire issues. Forecast increase of $0.8 million in the DPP4 period.

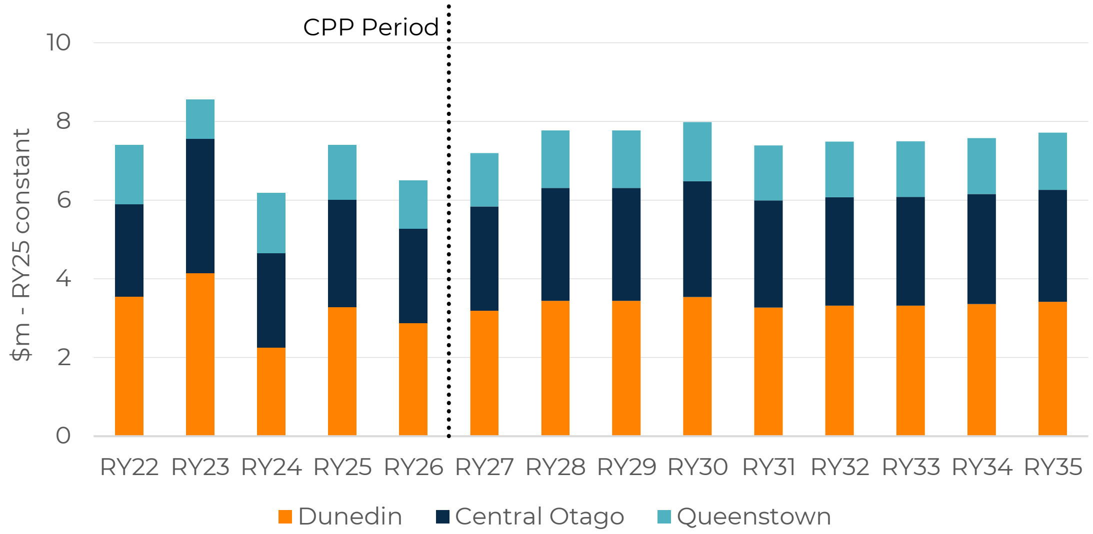
- Enhanced distribution switchgear inspections to enable deferral of switchgear renewals.. Forecast increase of $1.5 million in the DPP4 period.
- $1.4 million of deferred preventive maintenance from the DPP3/CPP period into the DPP4 period.
- Other small step changes including the inspection of consumer poles.
- Application of the Commerce Commission 2019 trend factor for change in network scale of 0.97% per annum to our forecast.

The step changes summarised above are outputs from the Fleet Strategies and root cause analysis with a focus on safety-critical assets, and are therefore deemed necessary preventive maintenance activities.

Marking a further significant change from AMP 24, we have removed the previously reported step change associated with the new overhead inspection programme. This is due to our increased confidence in the costs associated with this activity.

For a summary of our preventive maintenance activities by fleet, refer to Appendix G.

Figure 11-1: Preventive maintenance opex forecast by region (RY25 constant, $m)



As we undertake a detailed review of our preventive maintenance activities, including a review of our maintenance strategies with respect to enabling asset management objectives, we are actively identifying opportunities to enhance and optimise our preventive maintenance investment.

Our forecasts assume some deferral of preventive maintenance activities – into and spread over the DPP4 period – before we reach our currently-forecast steady state of preventive maintenance expenditure.

Our forecast preventive maintenance budget per asset category during the AMP period is outlined in Table 11-5.

Table 11-5: Preventive maintenance opex forecast by portfolio category (RY25 constant, $,000s)

Asset Portfolio	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Overhead Support Structures and Conductor	2,918	2,282	2,370	2,586	2,564	2,742	2,464	2,536	2,512	2,586	2,672
Underground Cables	128	124	144	157	158	160	150	151	153	154	156
Zone Substations	1,269	1,229	1,430	1,553	1,568	1,583	1,486	1,500	1,515	1,529	1,544
Distribution Switchgear	2,493	2,287	2,582	2,754	2,754	2,764	2,595	2,602	2,609	2,598	2,623
Distribution Transformers	484	468	545	592	598	603	566	572	577	583	589
Secondary Systems	108	105	122	132	133	135	126	128	129	130	131
Total	**7,400**	**6,495**	**7,192**	**7,773**	**7,775**	**7,987**	**7,387**	**7,489**	**7,495**	**7,581**	**7,715**

Note: Expenditure categorised outside of the breakdown outlined in the above table is distributed evenly across all fleets.

11.2.2. Corrective maintenance

The expenditure in this portfolio reflects the cost of corrective maintenance undertaken by our service providers.[7] Expenditure in this category includes defect rectification, repairs, and replacement of minor components to restore assets to operational condition.

The need for corrective maintenance is identified through the preventive maintenance program, and additional capacity can generally be used to address the backlog of less critical defects (otherwise captured by reactive maintenance). Due to the accelerated preventive maintenance programme, we are identifying a higher volume of defects that need to be addressed. However, as our preventive maintenance programme reaches a steady state, we expect corrective maintenance to follow suit.

10-YEAR OPEX FORECAST

For corrective maintenance, the base forecast is typically calculated using a three-year average for each portfolio subcategory of maintenance. The step forecast is developed by identifying the forecast cost of known changes to corrective maintenance practices or short-term programmes of work not previously undertaken under the base plan.

Step and trend changes incorporated into the corrective maintenance forecast include:

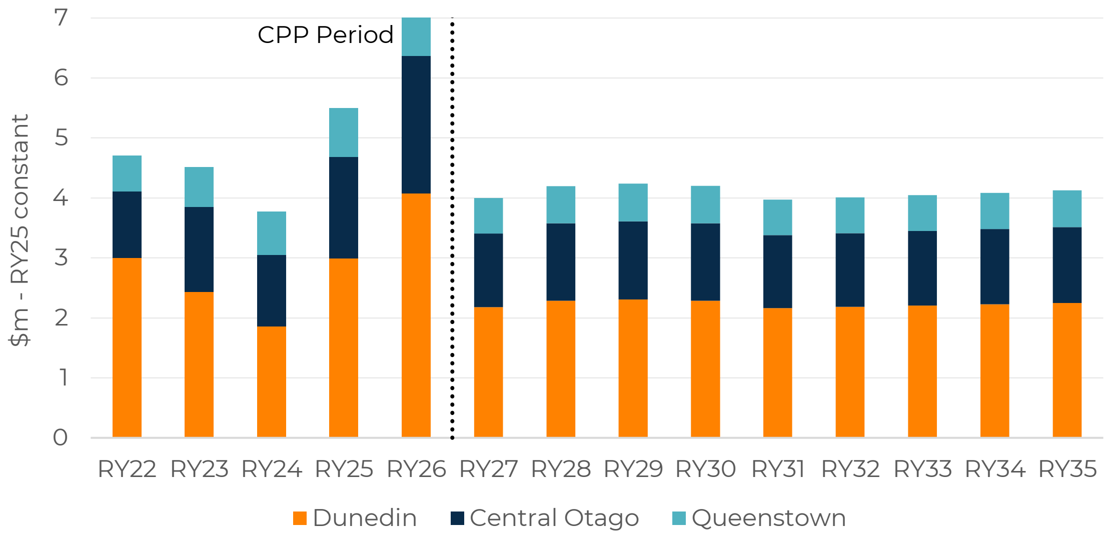
- Consumer pole remediation: We have incorporated our latest data into the forecast, which has a significant impact on our expenditure in RY26.
- Deferred/rollover maintenance: Forecasting deferral of maintenance from RY25 and RY26, out into RY28, RY29 and RY30
- Increased defect discovery and remediation from an enhanced ring main unit (RMU) inspection regime
- Increased crossarm and conductor defect find rate due to an area-prioritised acoustic inspection programme
- Application to our forecast of the Commerce Commission's 2019 trend factor for change in network scale, of 0.97% per annum

We do not consider it viable to delay any of the above step changes, which are all strongly linked to addressing public safety risks.

Figure 11-2 shows the forecast corrective maintenance budget for the AMP period.

[7] All corrective maintenance expenditure is covered under the Operational Expenditure ID category in the Routine and Corrective Maintenance and Inspection (RCI) line item and is included in **Schedule 11b** in the appendices. Note that corrective maintenance expenditure does not directly align with ID categories, but rather makes up part of the RCI category, together with preventive maintenance.

Figure 11-2: Corrective maintenance opex forecast by region (RY25 constant, $m)



Our forecast corrective maintenance budget per asset category during the AMP period is outlined in Table 11-6.

Table 11-6: Corrective maintenance opex forecast by portfolio category (RY25 constant, $,000s)

Asset Portfolio	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Support Structures	2867	4870	1019	971	980	910	872	881	889	898	906
Overhead Conductors	210	208	238	259	261	264	248	250	252	255	257
Underground Cables	297	294	338	367	370	374	351	355	358	362	365
Zone Substations	1190	1179	1353	1468	1483	1497	1407	1420	1434	1448	1462
Distribution Switchgear	307	306	338	359	362	366	351	354	358	361	365
Distribution Transformers	492	487	560	607	613	619	582	587	593	599	604
Secondary Systems	136	134	154	167	169	170	160	162	163	165	166
Total	**5498**	**7479**	**4000**	**4197**	**4238**	**4200**	**3970**	**4009**	**4047**	**4087**	**4126**

Note: Expenditure categorised outside of the breakdown outlined in the above table is distributed evenly across all fleets.

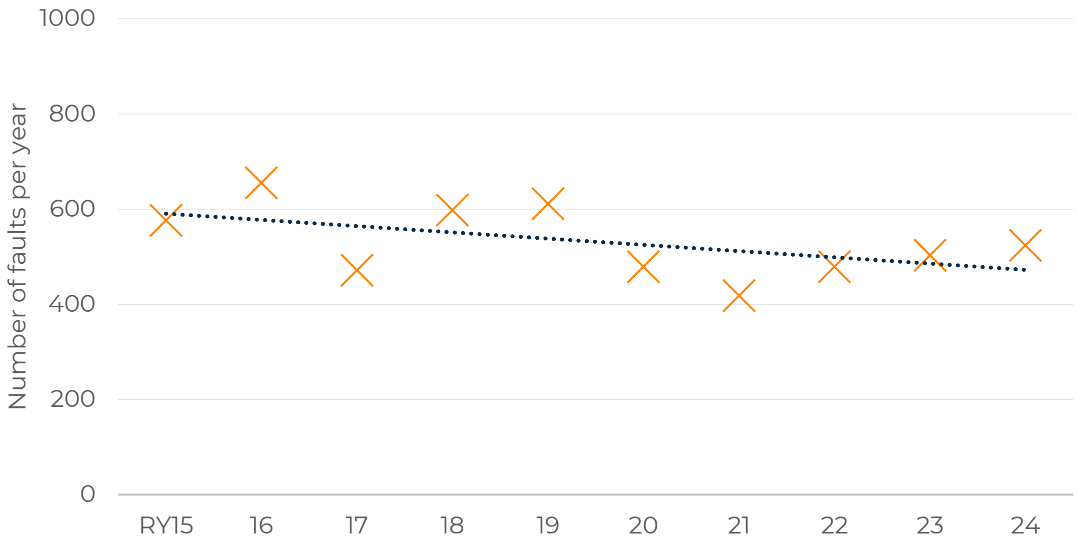
11.2.3. Reactive maintenance

Reactive maintenance is typically the response to a fault or unplanned outage. Unlike preventive and corrective maintenance, reactive maintenance usually requires immediate response and needs to be available around the clock. This is coordinated by our Operations and Network Performance team.

The performance of our assets on the network has a direct impact on the reactive maintenance portfolio. When an asset fails in service, we respond to it as 'reactive maintenance', which is not favourable and can be an indicator of the effectiveness of our asset management and asset maintenance strategies. However, such work can also be necessitated by issues impacting the network that are unrelated to the health of the assets, including weather events, impact from out-of-zone vegetation, and third-party damage such as vehicle impact.

Figure 11-3 shows the historical fault numbers have been reducing over time. We note that over the long term there has been a downward trend in the number of faults.

Figure 11-3: Historical fault numbers (RY15–24)



The amount of work we undertake in other maintenance or renewal portfolios affects reactive maintenance volumes in the longer term. For example, the decrease in faults shown in **Figure 11-3** can be linked to an increase in renewal work on the overhead network, which has improved the overall condition of assets on the network. Similarly, an increase in corrective maintenance will also gradually reduce the amount of reactive maintenance that is required in the longer term.

The expenditure in this portfolio reflects the cost of reactive maintenance undertaken by our service providers.[8]

10-YEAR OPEX FORECAST

As with corrective and preventive maintenance, our reactive maintenance forecast is developed using a base-step-trend model. The factors used as step changes or trends may include reliability performance, planned changes in approach to address emerging issues, step changes for new requirements, and escalation to account for growth of the network.

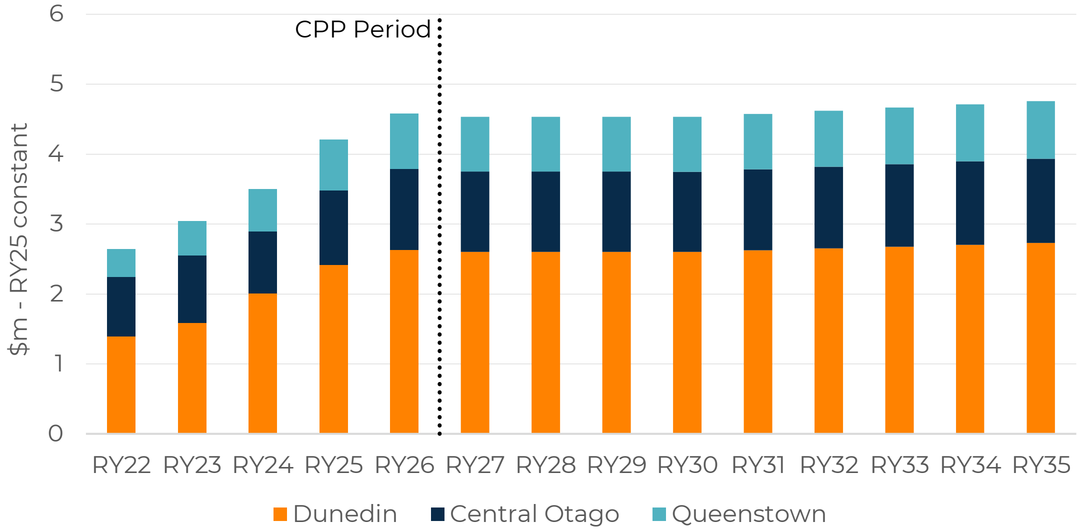
The base expenditure is informed by historical data, recognising that while we have seen a decline in reactive maintenance over the past five years, it is not reasonable to expect that trend to continue.

Step and trend changes incorporated into the reactive maintenance forecast include:

- Allowance for costs associated with enhanced contractor standby requirements to enable better fault response
- A trend assumption regarding improved network performance
- Allowances for increased labour costs as per contract terms for field services (FSA2) in RY26
- Application to our forecast of the Commerce Commission's 2019 trend factor for change in network scale, of 0.97% per annum.

[8] All reactive maintenance expenditure is covered under the *Routine and corrective maintenance and inspection* (RCI) line item in the Operational Expenditure ID category and is included in **Schedule 11b** in the appendices. Note that reactive maintenance expenditure does not directly align with ID categories, but rather makes up part of the RCI category together with preventive maintenance.

Figure 11-4: Reactive maintenance opex forecast by region (RY25 constant, $m)



11.2.4. Vegetation management

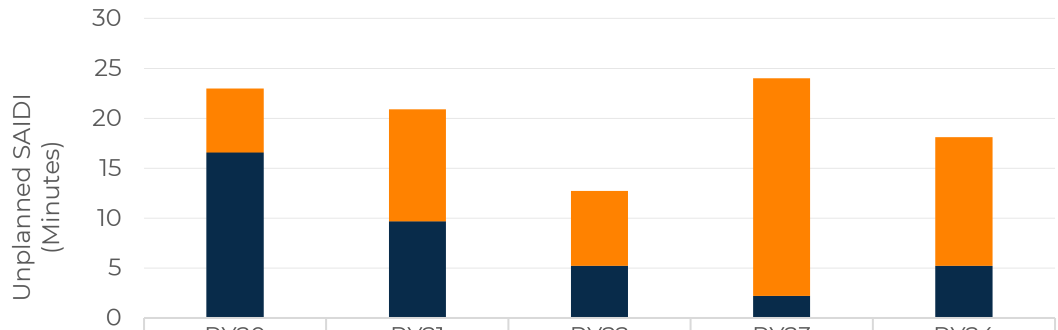
Vegetation management is guided by the Electricity (Hazards from Trees) Regulations 2003 (Tree Regulations) and involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of overhead lines.

Vegetation growing near powerlines can have a significant impact on the safety and reliability of electricity distribution networks and is a common problem faced by all distribution networks, particularly during severe weather events. To manage this risk, we dedicate a significant portion of our operations costs to our vegetation management programme. Under this programme, we perform regular inspections of our overhead network to identify vegetation growing close to overhead lines. We also face additional costs to ensure encroaching vegetation is trimmed or removed to safe clearance distances.

Under the Tree Regulations, we are required to manage vegetation to ensure public safety and a reliable supply of electricity. The chart below indicates a general improvement in the impact of vegetation faults in recent years, particularly for issues within the regulated clearance distances. Out-of-zone vegetation, which is not currently covered in the regulations, has had a greater negative impact on reliability, as shown in **Figure 11-5** below.

The ENA is presently reviewing the tree regulations, and this process is now at the consultation stage. To enable effective alignment and inform budgeting requirements in the case of a change in the regulations, we are now investigating all out-of-growth-limit zone tree strikes with data captured in a meaningful and useable way.

Figure 11-5: Vegetation SAIDI performance — Inside zone vs outside zone



	RY20	RY21	RY22	RY23	RY24
Out of Zone	6.4	11.2	7.5	21.8	12.9
In Zone	16.6	9.7	5.2	2.2	5.2

Historically, our approach was largely reactive, whereby crews responded to issues as they were identified by line inspections, third-party reports, or network faults.

In March 2022, we completed an initial round of inspections and maintenance across the network. Our current assessment is that vegetation defects on the distribution network are best identified by undertaking five-yearly vegetation inspections complemented by mid-cycle inspections conducted as part of the overhead line inspection. Subtransmission feeders are subject to annual inspections and management activities. This approach gives us better visibility of the status of vegetation around lines and enables us to minimise risks before they impact upon network safety and reliability.

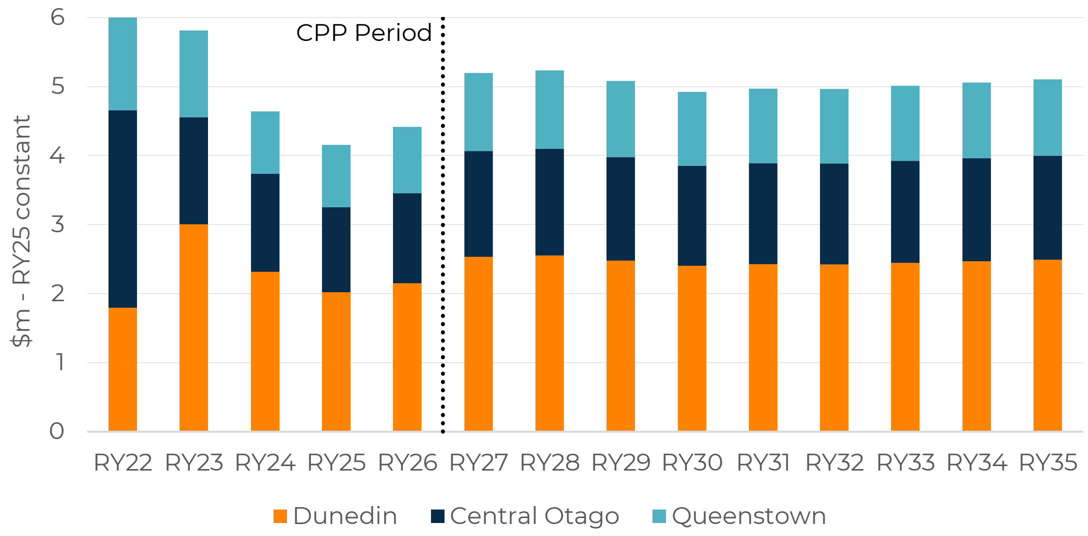
The key drivers for expenditure in this portfolio are to:

- Provide for the use of satellite imagery to support transition to a risk/condition-based approach to vegetation management
- Provide a safe network for the public, our staff, and contractors
- Comply with the Tree Regulations
- Reduce the risk of vegetation-related events damaging network equipment
- Provide a reliable network for consumers and meet agreed service levels.

10-YEAR OPEX FORECAST

Aurora Energy has now completed the 'first cut' across the network. **Figure 11-6** shows a drop in expenditure from RY24, indicating that we expect to trim or remove less vegetation than in previous years. We also anticipate transferring a greater share of costs to tree owners for trees requiring a second cut, pursuant to the Tree Regulations. Given the tree regulation amendments and our intention to move to a risk/condition based approach, forecast expenditure for vegetation management will increase from 2027 in accordance with the above drivers.

Figure 11-6: Vegetation maintenance opex forecast by region (RY25 constant, $m)



Given the recent amendments to the tree regulations, we have made modest provisions for clear-to-sky amendment of $0.75m and managing out-of-zone risks of $1.6m over the DPP4 period. Details of these changes are set out in Table 11-7.

There are some areas where there is potentially a need to change our management approach based on an assessment of risk, and this may result in additional costs.

Table 11-7: Vegetation management future revisions

Revision	Description
Updated Tree Regulations (revision)	The tree regulations were updated in October 2024 with a key change that the growth limit zone has been extended to *clear to sky* on HV (greater than 11 kV) uninsulated conductors and conductors with spans of more than 150 m, with a grace period until October 2026. These changes impact 18% of Aurora Energy's network, but data is not yet available to determine additional cut requirements.
Second cut costs (potential change)	Under the current regulations, vegetation cutting costs are shared between Aurora Energy and tree owners. We are responsible for meeting the cost of a first cut for all trees growing inside the regulated distances, and tree owners are then responsible for future cutting costs. As part of our transition to a steady-state programme, we expect that a greater share of cutting tasks will be under a second cut. As such, we forecast lower levels of expenditure from RY25.
Managing out-of-zone risks	Fallen trees, branches, and debris have the potential to cause significant damage to overhead lines, particularly during weather events. Under the existing tree regulations, we can only issue notices to landowners when their vegetation grows within set clearance distances from our lines. As such, we have limited authority to manage many vegetation risks that occur outside of these zones. In RY23 and RY24 we experienced an increase in SAIDI from out-of-zone vegetation. These risks present an ongoing reliability concern and we have made some budget allowance to address at-risk trees in the case of successful negotiations with the associated tree owners. As tree failure RCA and inspection data matures, and if the tree regulations change as proposed, we will look to additional expenditure to address this issue.

We have initiated a review of our vegetation management strategy and standard to consider the merits of a transition from a cyclic to a condition/risk-based approach. With the completion of the first cut programme and a wide variation in the growth rates of different vegetation species there is potential for a condition/risk-based approach to improve safety and reliability performance without an increase in cost. We are also considering the potential benefits of utilising AI and satellite imagery to track the state of vegetation and establish growth rates on a specific vegetation location basis.

11.2.5. Improvement initiatives

We aim for continual improvement of our asset management practices and therefore continually review the performance of the network and the effectiveness of our maintenance activities. This means we are constantly seeking to optimise the level of expenditure needed to manage safety and reliability risk.

We are working to advance our understanding of certain failure modes so that we can optimise the timing and therefore cost associated with intervention strategies – whether in the form of maintenance or renewals. We are also looking at technologies to enable us to assess the condition of assets in a more cost-effective way without compromising on quality.

We are enhancing our inspection programmes to enable greater data confidence and enhanced expenditure decision-making. This is an iterative and continual process that requires us to respond to learnings from asset failure investigations in order to optimise how we assess and evaluate condition and remaining life.

We are also doing work to enhance our understanding of how our assets perform and fail so we have a better understanding of failure modes and failure rates – which we will use to drive optimised expenditure, from the perspectives of both renewal and maintenance. The following are some of the key initiatives that we are currently progressing.

LEANING POLES

Through 2023, Aurora Energy actively participated in an industry-led study aimed at establishing evidence-based rules for evaluating pole lean, for a consistent approach across multiple EDBs and ultimately an enhanced understanding of the ideal thresholds for intervention (i.e., how much of a lean is tolerable before there is an elevated risk of failure). This study included physical scale model tests to support the formulation of improved assessment criteria.

Supported by the findings of the study, in RY24 we identified poles that were being tagged for renewal based on lean only, and undertook individual engineering assessments – in some cases confirming that renewal can be deferred. We have also taken some more specific learnings from the subsequent stages of the study. Applying this in practice will add complexity to our inspections, thus driving the need to build additional functionality into our inspection application. We are planning to implement this on the next update of our overhead inspection standard and inspection application. We anticipate that this will result in a more targeted focus on poles requiring rectification, whether through straightening or replacement. This initiative underscores Aurora Energy's commitment to enhancing the safety and value-driven efficiency of its fleet by addressing a specific and challenging risk condition through proactive, evidence-based practices.

VONAQ TESTING

Aurora relies on the mechanical pole testing (MPT) system as its primary method for assessing pole condition, and this has proven to be a reliable tool. However, this system comes with notable drawbacks – in particular, the weight of the equipment required, which can make accessing certain poles challenging and places a significant physical demand on inspectors.

To address these issues and ensure we are prepared in case of future technology support constraints, Aurora Energy has actively pursued a policy of evaluating and testing emerging and alternative pole testing systems. The aim is to identify and make available the most suitable testing technologies for inspectors. As part of this initiative, the Vonaq testing system has undergone an 18-month trial on the Aurora Energy network. The goal of this trial is to understand whether the system would provide us with continuity in our assessment of the condition of poles.

Thus far, positive results have emerged from the Vonaq testing system, and ongoing trials are planned for RY26. This reflects Aurora's commitment to staying at the forefront of technology and adopting solutions that enhance efficiency, add to our toolkit, and also address the physical demands on inspectors during evaluations of pole condition.

ENHANCED ASSET INSPECTIONS

In 2023, we began to use a new and enhanced overhead inspection system featuring a new IT platform, Survey123, along with an updated comprehensive Overhead Inspection Standard. We now inspect all overhead assets at the same time, against the new standard. With approximately 20% of feeders inspected using the new system, it is apparent that this system is delivering the anticipated value. It is directly informing adjustments to our investment planning by, for example, providing us with sufficient evidence to override previous crossarm health assessments that indicated poor health.

As part of our ongoing investment in improving our asset management practices to enable evidence-based investment decision-making, we are undertaking a wider review of inspections for all fleets. In 2024 we published new inspection standards for LV enclosures, distribution transformers, and distribution switchgear.

In 2025, we plan to build on the advances achieved thus far as we develop further inspections and embark on a cycle of continuous improvement with the aim of raising the quality of the data we use to manage our assets.

ACOUSTIC INSPECTION

Acoustic inspection will accurately detect electrical discharge from deteriorating in-service overhead high voltage assets – something that can be extremely difficult to detect by eye. This is an advanced inspection technique that has proven to be very effective for discovering certain types of defects, often before they can possibly be visually detected.

The inspection can be carried out from a moving vehicle if assets are accessible and within 15 metres of the road centreline. A well-planned inspection enables a high coverage cost-efficient undertaking. Post-inspection analysis determines time to asset failure, enabling robust intervention planning.

Proactive identification of failing assets enables managed intervention before the asset fails – which typically brings more severe consequences such as longer and more widespread outages and higher risk. Typical defects identified are:

- Cracked/broken insulators/bushings
- Insulator contamination
- High-resistance connections

- Broken conductor strands
- Partial discharge on cable terminations
- Failing binders
- Vegetation interference

The Dunedin sub-network has a high volume of roadside assets within a reasonably compact coastal environment. As such, based on the value ascertained from previous acoustic inspections, we have implemented biennial acoustic inspections of the entire Dunedin HV and EHV network.

We have also implemented an annual springtime acoustic inspection on assets in FENZ's prohibited fire zones in the Central Otago & Wānaka sub-network.

This inspection technique has also proven to be a useful tool for responding to network performance issues in certain circumstances: Aurora Energy has carried out acoustic inspections on feeders that have had transient type faults that fault-patrol visual inspections have been unable to detect, with positive results.

EARLY FAULT DETECTION SYSTEM

The early fault detection (EFD) system is a new technology that continuously monitors electrical infrastructure at radio frequencies. It scans the infrastructure at one second intervals to detect electrical discharge (micro arcing), allowing proactive intervention against emerging faults and thereby enabling proactive intervention prior to failure. The technology has been trialled and is now being used successfully in Australia and America.

The technology consists of solar powered EFD collection units installed at four- to five-kilometre spacing on the overhead line feeder. These units detect signals and measure their energy and arrival time, communicating to an EFD portal server via 3G or 4G.

The system's software carries out analysis using algorithms that calculate signal source and strength to identify and locate emerging faults to within 10 metres. Alerts are sent out for high-risk issues, and upon notification of an emerging fault, technicians are despatched to the location of interest to determine the cause of the micro arcing and initiate repairs as required. The technology also realises another benefit: in the event of a non-detected actual failure of a line component due to an event such as a bird or tree strike, the technology will identify the actual location, enabling a significantly quicker fault response and saving line patrol time.

This technology was installed on the OM33 feeder in May 2024. This is a radial subtransmission feeder with *N* security (meaning there is no backup supply) constructed predominantly across country, which makes fault detection challenging. Servicing 900 ICPs, this feeder is approximately 26 kilometres long, with conductor installed in 1968. Assuming a typical four-hour outage, the estimated volume of lost load (VoLL) is $240,000.

The expected benefit of EFD is an improvement in SAIDI and SAIFI to consumers where the technology is deployed, as well as a reduction in the risks of property damage and injury arising from overhead asset failures.

Data analysis following installation identified a number of sites with activity. Inspection findings from these locations found insulator and conductor defects with differing levels of severity, enabling proactive mitigation where required.

We propose to undertake a post- (likely one-year after commissioning) implementation assessment of the technology to determine whether it has performed as expected against our expenditure test criteria, including whether it can be implemented more widely on critical subtransmission or 11 kV circuits across the network.

ASSET FAILURE ROOT CAUSE ANALYSIS

A comprehensive understanding and record of how, why, where, and when assets and their components fail is critical for building a robust asset management framework.

In RY24 we established an equipment failures database to record root cause analysis (RCA) information for unassisted asset and component failures. Equipment failures are investigated by the appropriate Lifecycle Engineers, who share and debate findings at fortnightly reliability meetings and then either sign off the RCA or initiate further actions as required.

Recording findings in a methodical and consistent way enables information trending, which identifies problematic design, material systemic issues, and construction shortcomings. Learnings enable us to improve our inspection frequencies and techniques, which in turn inform asset health and emerging asset failures, thereby facilitating proactive intervention. They also enable improvements in design and construction methodologies and material choice.

Recent learnings have initiated:

- Aurora Energy-approved ABS type change due to systemic issues with the existing model, with the new ABS selected using Aurora Energy's NEMA evaluation process
- A review of the nut, bolt, and washer choices for attaching crossarms to poles
- Notices to contractors advising on construction methodologies

The RCA process is treated with a continuous improvement approach wherein failure modes continue to be identified after investigations are completed and the process is refined as learnings and experience become apparent. Our medium-term intent is to establish a library of failure modes, to lock in an associated process once this has been fully refined, and to systemise data collection where effective.

COMPOSITE ARMS NEMA

A new equipment and materials application reached business approval in RY25, facilitating a change from wood and steel crossarms to composite. Composite crossarms have insulation properties, will not ignite, are lighter – which both reduces transport emissions and lowers handling risk – and are an engineered product, thus removing the performance variability of wood. The expected outcome, which is supported by research and communications with other networks that use them both here and in Australia, is a lower lifecycle cost and improved reliability due to a long-term reduction in failures. We are currently updating designs and standards with a plan to start installing composite crossarms as the preferred crossarm for HV construction in RY26.

11.3. SUPPORT STRUCTURES

This section describes our support structures portfolio and summarises how we manage the following asset fleets:

- Poles
- Crossarms

Poles and crossarms are key components of our network, providing sufficient clearance for our overhead conductor to safely supply electricity to consumers. Poles and crossarms also support other assets including distribution transformers, air break switches, and third-party assets such as streetlights, communication assets and road signs. They must provide the necessary performance to maintain a safe and reliable network.

Most of our overhead network is accessible to the public, so managing our support structures is a priority for us in terms of ensuring public safety – particularly in urban areas.

11.3.1. Poles fleet

Our support structures carry conductor operating at all our network voltages. We have approximately 53,000 poles across our network. These are primarily wood and concrete, with a small number (approximately 1,900) of steel poles. The key characteristics of our fleet are as follows:

- Pre-stressed concrete poles are manufactured with tensioned steel tendons (cables or rods). They are a mature technology and generally perform reliably over a long period. Most of the new poles we install are pre-stressed concrete, with a design life of 75 years. They are designed and manufactured to meet stringent structural standards.
- Mass-reinforced concrete poles contain reinforcing steel bars covered by concrete and were regularly used from the 1960s to the 1980s. These poles were produced by several manufacturers for different areas of our network, which has resulted in differences in design, manufacture and material quality. They have a common deterioration mode where water ingress through cracks corrodes the steel reinforcement.
- Wood poles are categorised into *hardwood* and *softwood*. There is no single method to reliably assess all aspects of the condition of wood poles; however, we have developed and refined a robust framework and tools to test and understand the strength and likely remaining life of our wooden pole fleet. Failure modes include loss of cross-section due to below-ground rot, splitting through the body, and split heads.
- Steel poles are predominately Valmont steel poles. These are cold-formed hollow steel poles of various heights, diameters, and thicknesses.

Table 11-8 summarises our population of poles by type and sub-network.

Table 11-8: Overview of poles by sub-network, type, and age

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Hardwood pole	8003	6714	1734	16451
Softwood pole	2295	2154	922	5370
Concrete pole	18391	9615	1818	29824
Steel pole	334	1360	173	1867
Total	**29,022**	**19,843**	**4,647**	**53,512**

The rating of a pole is typically based on the highest voltage asset attached to it. Table 11-9 summarises our population of poles by voltage.

Table 11-9: Overview of poles by voltage

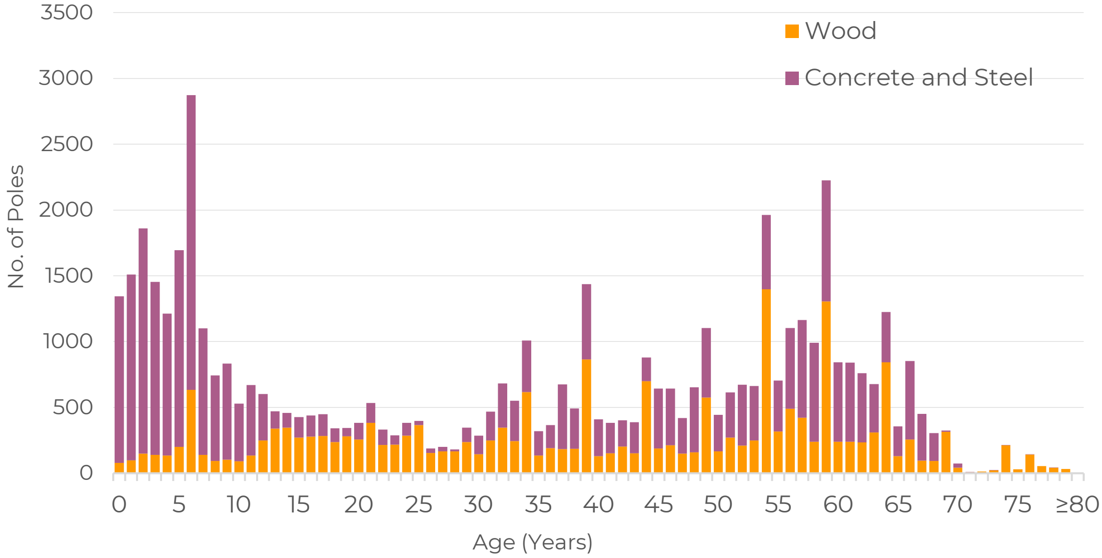
	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
33 kV	2675	2123	782	5580
66 kV	6	1400	3	1409
HV	13707	13800	3090	30597
LV	12784	2528	774	16086
Total	**29172**	**19850**	**4649**	**53671**

ASSET AGE

Figure 11-7 shows that a number of our hardwood poles have exceeded, or soon will exceed, their expected life expectancy of about 50 years.[9]

In contrast, very few concrete and steel poles have exceeded their 75-year life expectancies. The average age of our concrete poles is approximately 32 years, against 41 years for wooden poles.

Figure 11-7: Poles age profile



[9] Estimated from our wood poles survivor curve, which is informed by historical data.

ASSET HEALTH

The condition of poles is determined by various methods, such as visual inspections, dig testing, and more advanced systems such as Deuar testing, conducted every five years. The resulting grades indicate the ability of the poles to support normal or design loads. Poles assessed as grade H1 under the Aurora Energy grading system have mandatory intervention times of three months or one year, based on the criteria set out under the Electricity (Safety) Regulations 2010, and are marked with red or orange tags onsite. Poles with grades H2 to H5 have indicative intervention times assigned by Aurora Energy.

Given we inspect at five-year intervals, we are working toward eliminating the backlog of all poles graded H2 and below. We use the condition grading information for grades H3 to H5 to inform our 10-year forecast. Poles also have a criticality rating from 1 to 5, which helps us prioritise pole replacements. Typically, poles with a higher criticality rating are replaced first.

As an additional control, we have implemented a sample programme of re-inspection on H2 poles that are coming to year three since their last inspection. This helps with the inherent uncertainty around the pace at which poles – particularly timber poles – will continue to degrade.

As we mature our understanding and management of asset risk, we continue to refine our methods for assessing asset health. Previously, we estimated the health of poles primarily using age and expected survivorship. However, age-based AHI models are often misleading, as asset operation and the effects of the environment can significantly impact the life of the asset. Thus, we developed an AHI model that uses pole grades and condition data obtained through inspections. By combining pole age and condition data, we can modify the base maximum practical life to predict the remaining pole life. This is a proprietary solution developed in-house, which we are validating with field data. To maintain consistency, this AHI model has been adjusted to align with Aurora Energy's new Overhead Inspection Standard (AE-FA01-S).

In addition to using pole grades (the strength of the pole based on the type of wood and preservative treatment) to adjust the expected life, the AHI model considers poles that have been reinforced or which have been identified as having deteriorated at or above the crossarm connection point.

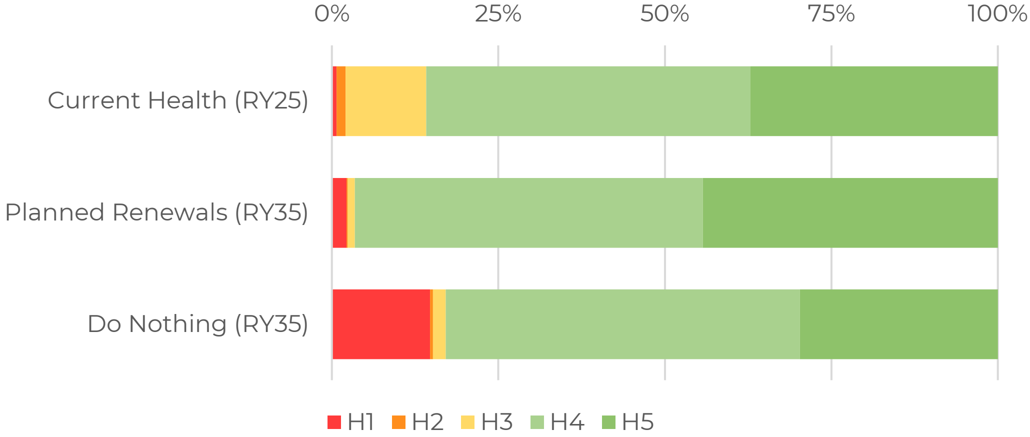
Where we reinforce a wood pole, we assume a remaining life of 15 years, so these become classified as H4. In some cases, this may overstate the remaining life due to above-ground defects requiring early pole renewal, but we do not consider that this will significantly impact our forecasts over the AMP planning period.

We have modified the pole AHI model to better handle asset replacements undertaken as part of other projects. An additional input has been included to identify poles that have not been prioritised based on their AHI score but will be replaced as part of another project. This ensures the poles are modelled correctly and improves the accuracy of our forecast network health and risk profiles.

For concrete and steel poles we estimate the remaining pole life using an age-based model, where we subtract the pole age from the expected life of 75 years. Each pole is then classified as H1 to H5. Assets at H3 are within 10 years of their expected life, so will need to be considered for replacement within the AMP planning period. However, it should be noted that the inspection cycle ensures every asset is inspected, with heath rating updated, every five years.

Figure 11-8 shows the current AHI profile of our network and our forecast profile in 10 years' time based on our planned programme of works and the counterfactual case of not undertaking any replacements.

Figure 11-8: Projected pole asset health



When prioritising poles for inclusion in our renewal plan, we consider health alongside the safety criticality of the location. For example, we may prioritise an H2 pole located outside a school over an H1 in a remote field.

The plan has been informed by the need to manage risk while flexing the budget to facilitate growth.

The model also treats nailed poles (that are otherwise sound) in a simple way: they are either H4 or H1. The recommended life of the nail is 15 years, so once 15 years have passed since nailing, the health is recategorised in the model to H1. We have 3445 nailed poles coming to 'end-of-life' during the planning period.

Because the nails were all installed during a 2½ year period, the planned replacements have been smoothed over the 10-year planning period and aligned to the cyclic feeder inspection to avoid a volumetric replacement spike.

Where we have deployed this life-extension strategy on a section of the network, line renewals will take into account the life extension recommendations.

It is also noted that the vast majority of poles showing as H1 in RY34 are earmarked for replacement in RY35. This timing is reflective of their location or safety criticality zoning.

While the budget year is risk prioritised, informed by condition, the 10-year forecast is informed by age, with some time-based assumptions around when we transition from one health score to the next.

ASSET PERFORMANCE AND RISK

Failure of a pole in service is a significant safety issue, potentially exposing the public or field staff to hazards associated with falling equipment and live conductor on the ground (or with reduced ground clearances). It also presents a reliability issue, as a pole failure will generally result in loss of supply or reduced network security. Failure of a structure during maintenance or construction work presents a significant workplace safety hazard.

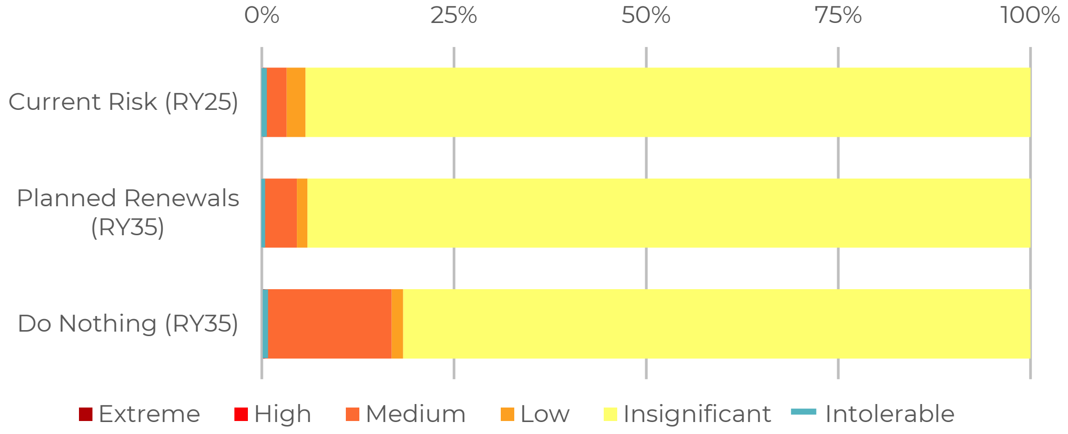
Table 11-10 sets out the failure modes (including systemic risks for this asset class), the risks posed by the failure mode, and how Aurora Energy is managing the risk. Level of risk is assessed as a function of asset health and asset safety criticality. Assets in Criticality Zones 1–3 are prioritised accordingly.

Table 11-10: Key pole risks and mitigations

Risk/Issue	Mitigation
Below-ground rot/deterioration: Weakening of the pole to the point where it fails and can fall over, bringing live assets into contact with the ground/people. Impact on safety and reliability.	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Where poles fail the test criteria, options for replacement are considered. Typically, this would mean replacement with the current standard pole.
Car v pole: Poles are commonly located adjacent to roads, bringing the risk of cars colliding with poles.	Poles are relocated or undergrounded where possible.
Corrosion of steel reinforcement: Concrete spalling falling onto pedestrians/workers; weakening of the pole, resulting in failure.	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.
Foundation failure: Pole failure	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.
Fungal rot of wood due to moisture (pole head): Detachment of crossarm	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.
Structural/mechanical failure (loading exceeding design load limits): Pole failure (public safety)	Pole test systems used from 2017–2023 have included a loading assessment functionality. New pole installs are designed to AS/NZ7000.
Vandalism	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.
Animal interference (ground damage): Pole/foundation failure (public safety)	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.
Steel pole corrosion: Pole/foundation failure (public safety)	Poles are inspected and tested on a cyclic basis, as described in the Preventive Maintenance Activities Table in Appendix G. Rectification is undertaken when required.

The reduction in the number of poles categorised as *Intolerable* (those to the left of the vertical blue line in Figure 11-9) demonstrates how our renewal programme will reduce network risk over the AMP period.

Figure 11-9: Projected pole risk



REPLACEMENT/RENEWAL

When a pole is identified as having reached the end of its serviceable life or as posing a risk above our risk tolerance threshold, we undertake options analysis to consider the lowest overall cost approach to managing the risk it presents. This includes consideration of opex/capex trade-offs.

Refurbishment or strengthening options for poles include an assessment of the nature of the defect and the viability of interventions other than renewal. Options include:

- **Replace:** All condition issues or defects on the pole are remediated.
- **Strengthen:** Compromised poles can be strengthened at the ground by 'nailing', which can extend the pole's life by 15 years.
- **Straightening or stay wire installation:** This can be an effective means of stabilising leaning poles.
- **Undergrounding:** In rare cases, replacement above ground may not be technically feasible due to modern clearance standards, or a customer may wish to fund undergrounding.
- **Repair:** It can be possible to repair some defects in reinforced concrete poles and wooden pole heads (opex). Crossarms are also replaced on existing poles (capex).
- **Replace:** Pole-mounted distribution substations can be replaced with ground-mounted distribution substations.
- **Reassess condition and/or strength:** In specific cases, detailed engineering analysis is undertaken to either validate or reverse gradings informed by the inspection process, which can result in deferring renewal for several years.
- **Non-network alternatives:** Where a significant amount of pole and conductor replacement is required on a line feeding a small number of customers, consideration is given to whether a remote area power supply is a more cost-effective solution. We have not implemented this solution to date but will continue to consider opportunities.

Pole nailing or reinforcement has been implemented as a life extension and risk management strategy for wood poles that have indications of rot at the base. These interventions are typically only undertaken if the risk of failure is high and renewal is not practical at the time or if it is known that more significant work (including relocation or decommissioning) is planned, rendering ad-hoc renewal economically unviable. The process applied when deciding when an asset should be replaced takes into account condition and criticality (safety sensitivity and location). Typical drivers for replacement are:

- Condition of pole base (safety risk)
- Condition of pole head (safety risk)
- Crossarm condition in combination with pole condition (economy of scale to replace both)
- Clearance breaches
- Customer-initiated projects (subdivisions, road alterations)
- Reconductoring and change of loading

RENEWAL PRIORITIES

TAGGED POLES

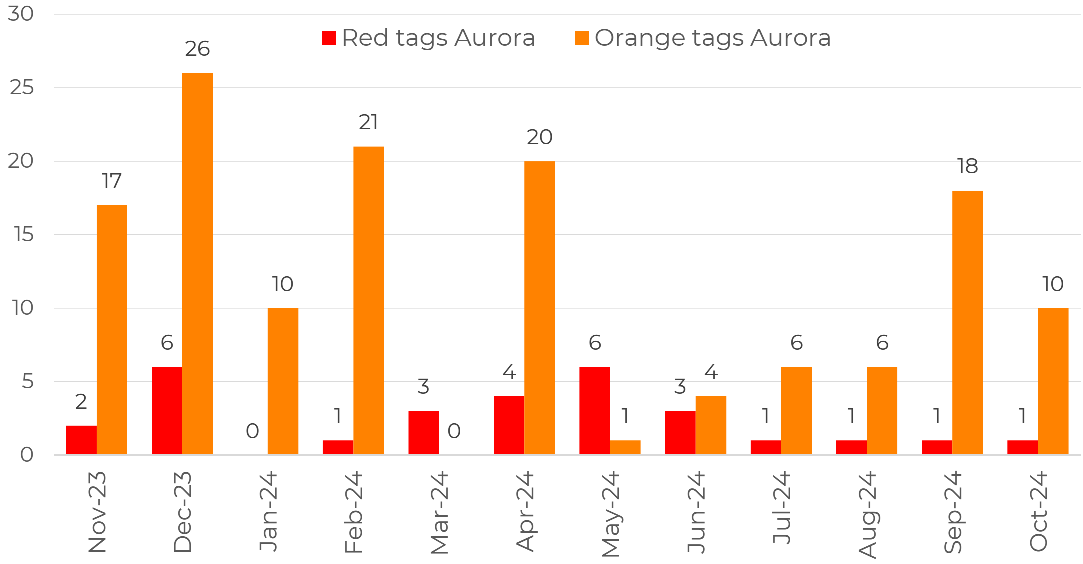
In AMP 2018, we noted that the need to address overdue red-tagged poles (not suitable to support everyday load requirements) in high criticality areas was an urgent priority. At that time, we had approximately 1,000 red-tagged poles on the network. In 2020, that figure was reduced to 157 poles, and by December 2022 we had reduced the number of red-tagged poles to 19, representing a population of predominantly under control recently-discovered red-tagged poles. As of October 2024, we had no red-tagged poles that were outside of compliance, which indicates that any new finds are being addressed within three months.

In October 2023, our population of orange-tagged poles (not suitable to support design loadings such as high snow/ice event loadings) stood at 472. As such, these poles have remained a focus for rectification in RY24–RY25.

As of October 2024, we had reduced the total of orange-tagged poles to 170, of which 62 were in backlog – i.e., not addressed within 12 months. However, 60 of these backlogged poles are with contractors for renewal. Rectification options include straightening, reinforcing, replacement, or review via detailed engineering/risk assessment. We have put plans in place to accelerate the progress of this targeted programme.

As shown in **Figure 11-10**, we actively track tagged poles so that we have visibility of progress, compliance, criticality zone, location, the status of the replacement plan, and discovery rate. On average, we discover 12 new orange tag and 3 new red tag poles per month.

Figure 11-10: Newly discovered red and orange tags



WAIPORI LINES

This remains a renewal priority as many of the oldest wood poles on our network have been identified along our Waipori A, B, and C overhead lines in the Dunedin area. Given our plans to replace this line, we have implemented a strategy of strengthening through nailing, as required. This enables us to optimise expenditure while managing risk.

In 2021, we replaced a section of the line including over 500 poles. A plan is in place to replace the remaining line within the AMP period, in a staged manner, from RY26. Under the proposed work programme, the wood pole backlog will be removed by RY32. We will continue to replace poor condition poles after this date, achieving our steady-state level (corresponding to 500–750 poles replaced per annum) by the end of the planning period.

DISPOSAL

CCA-treated softwood poles need to be disposed of at an appropriately licensed facility or appropriately repurposed.

FORECAST CAPEX EXPENDITURE

We have forecast renewal capex for poles of approximately $142m during the 10-year planning period, which is significantly more than forecast during our previous AMP. This change is informed by better data from our enhanced inspections, coupled with advances in our risk forecasting capability and improved condition assessment techniques. The additional expenditure also encompasses the 60% increase in contractor costs from the beginning of the CPP period and the cost of associated assets (any pole-mounted equipment that requires replacement at the same time). Small quantities of repairs will be covered under opex, and undergrounding or remote area power supply scenarios are covered on a project-by-project basis.

As shown in **Figure 11-11**, our forecast expenditure has increased from RY25. There are a number of contributing factors behind this increase, including:

- Continued upward pressure on costs for overhead renewals and pole replacements
- A maturing view of asset condition and failure modes, which has enabled us to re-assess risk and intervention thresholds – for example, leaning poles
- Progress against SDP commitments for this fleet
- Increasing pressure to financially facilitate growth on our network
- Significant conductor renewal projects, such as the Waipori A, B, and C lines, where end-of-life poles will be replaced as part of conductor renewal projects – i.e., as associated assets.

While we are getting on top of the backlog for this fleet, our forecast expenditure has increased from RY25 – mainly due to the increased cost of delivering this work.

Our overhead cyclic feeder inspection programme is well balanced in terms of numbers of assets to inspect annually across the five-year cycle. The outcome of the inspections determines asset renewal volumes, which will vary from year to year.

To ensure a steady state of budgeting and forecasting and achieve efficient utilisation of our field service providers, our operating model enables some flexibility in annual conductor replacement volumes.

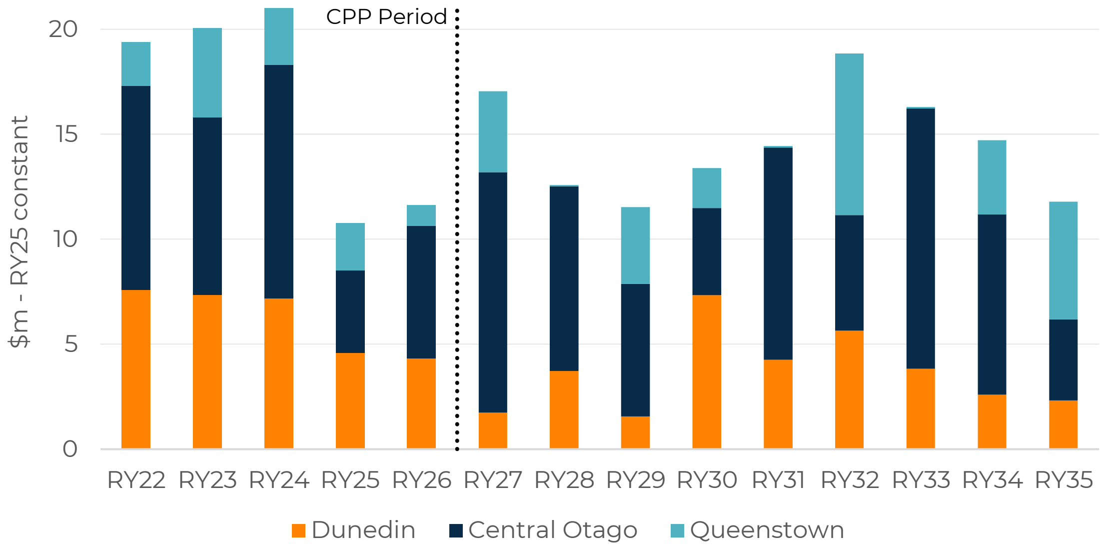
This work is aligned to the skillsets of the FSPs, enabling a steady state.

Table 11-11 and Figure 11-11 show specific programmes and expenditure. Note that the 500 poles called out in the Waipori A, B, and C lines project constitute poles replaced on top of the expenditure indicated in Figure 11-11.

Table 11-11: Programmes and expenditure

Programme	Description	Timeframe
Waipori A, B, and C overhead lines	Replacing more than 500 poles to address the deteriorated condition of the line, etc.	RY26–RY32
Condition-based replacement	Replacement of poles based on condition assessment in the field determining it no longer meets functional criteria.	Ongoing

Figure 11-11: Capex forecast poles by region (RY25 constant, $m)



11.3.2. Crossarms fleet

Crossarms support overhead conductors. A crossarm assembly comprises the crossarm and ancillary equipment such as insulators, binders and jumpers. Due to the different equipment suppliers, line designs, line voltage levels, and network owners involved in the development of the network over its history, our crossarm fleet consists of a variety of different types and configurations.

We have approximately 96,000 crossarms on the network, at an average of 1.7 crossarms per pole, typically carrying from two to five insulator sub-assemblies. The majority of crossarms on the network are wooden, although a limited number of galvanised steel crossarms are also used.

Table 11-12: Crossarm population

	Population				
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Unknown	Total
Crossarm	53873	28945	7131	6154	96103
Total					**96,103**

ASSET AGE

Our historical data sets do not have age entries for crossarms; however, in all cases where a pole is replaced, new crossarms are installed. Thus, we assume that all crossarms are the same age as the poles on which they reside. Retrofit crossarm age data will be captured going forward. Table 11-13 shows the average age of our crossarms for each sub-network.

Table 11-13: Average crossarm age by sub-network

	Age		
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown
Crossarm Assembly	39	27	29

ASSET HEALTH

Although we have some condition data from historical pole inspections, it is not fit for purpose, from the perspectives of both data quality and completeness.

In response to data gathered from historical pole inspections indicating that the crossarm fleet health was poor, and knowing some limitations existed in that data, we undertook some structural testing of decommissioned crossarms. The outcomes of this testing confirmed our suspicions over shortcomings in the crossarm condition data gathered under the first pole inspection programme.

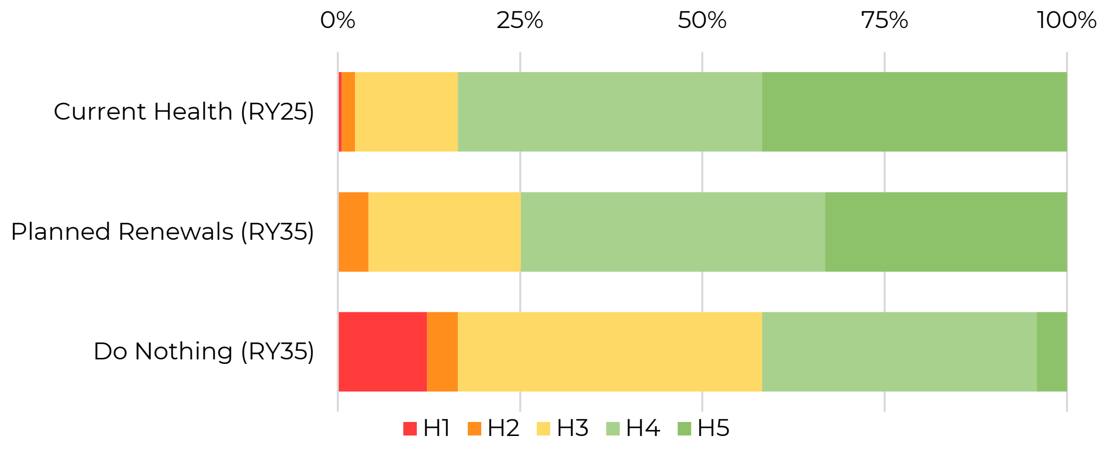
Since standing up the new improved overhead inspection programme, we have gained access to quality data, which further supports conclusions regarding these historic data limitations. Now that we have completed inspections of 20% of feeders with the new inspection programme, we are developing a more advanced understanding of the overall condition and health of this fleet.

It will take a complete five-year inspection cycle to gain the full benefit and insights of the updated inspection criteria. However, we expect the enhanced inspection regime to significantly improve the known health/condition profile of the crossarm fleet, through:

- Being informed by failure modes, not limited to structural failure – i.e., the ability of the crossarm to support the insulators
- Focusing on known crossarm failure mechanisms (end splits, burning, decay) with a reduced focus on the visual appearance (ageing, moss) of crossarms used in the previous assessment regime
- Capturing accurate position information on each inspected crossarm (facilitating targeted replacements)
- Shifting to inspecting all crossarms (in contrast to the 2017–2023 policy of inspecting crossarms greater than 10 years old), allowing identification of early-onset failure and construction defects

Aurora Energy's current crossarm health profile and forecast change has been determined by a statistical approach using data from the updated inspection standard. To date, 20% of our crossarms have been inspected to this standard. The output is summarised in Figure 11-12, signalling a significant reduction in investment in the 10-year plan. This will be reviewed and refined using incoming inspection data.

Figure 11-12: Projected crossarm asset health



ASSET PERFORMANCE AND RISK

Support structures by their nature may pose risks to public and personnel safety and reliability of service. Crossarms provide structural support to maintain clearance, including providing appropriate support to the insulators to which the conductors are connected.

Since instituting RCA of asset failures in 2023, we have established a robust basis for collecting data on the number and type of crossarm failures, enabling us to establish a baseline and measure the performance of crossarms. Table 11-14 sets out the key risks and mitigations we have identified in relation to our crossarms.

Table 11-14: Key crossarm risks and mitigations

Risk/Issue	Mitigation
Insulator leakage pole fire (generally pin type): On wooden poles, leakage current on insulators tracking along the wooden crossarm, down the crossarm brace to king bolt, starting a pole fire, often breaking the pole and leaving conductor floating above ground (potentially live) or falling to ground	Ground- and aerial-based inspection programmes leading to replacement of visually defective crossarms. New crossarms (except low voltage) have post insulators. Type-based replacement of otherwise non-defective pin insulator crossarms in polluted areas or areas experiencing multiple failures.
Intermittent fault caused by leaking pin insulator: Often the causal condition issue cannot be seen by the naked eye or average camera from the ground	Ground- and aerial-based inspection programmes leading to replacement of visually defective crossarms. New arms (except LV) have post insulators. Ad-hoc use of acoustic discharge test equipment to find intermittent faults.
Leakage/short to crossarm, or conductor down or conductor floating event: Significantly leaning insulator or failure of leaning insulator	Ground- and aerial-based inspection programmes leading to replacement of visually defective crossarms New arms (except LV) have post insulators. Replacement of all pin insulators on reconductoring projects. Installation of vibration dampers on 66 kV circuits with known aeolian vibration problems and failure history.
Wooden crossarm breakage: Wood ageing/ degradation	Ground- and aerial-based inspection programmes leading to replacement of visually defective crossarms.
Conductor down or conductor floating event: Binder failure	Ground- and aerial-based inspection programmes leading to corrective maintenance defect repairs.
Bird strike on steel crossarms: (Particularly in the case of the NZ Native Falcon/Kārearea), pole located in sighting/breeding area	Falcon guard retrofit programme on steel crossarms near falcon sighting/breeding areas.
Loss of secure connection between crossarm and pole or braces: Leading to vibration and eventual rotation or complete loss of support to the crossarm	We have identified through the RCA process a specific failure mode, as a result of which we have undertaken industry research and subsequently amended our design standards. We have also implemented a corrective maintenance activity and are actively inspecting security of bolts and nuts under the planned maintenance overhead inspection programme.

REPLACEMENT/RENEWAL

The following principles underpin Aurora Energy's current crossarm replacement strategy:

- Crossarms identified with a health grade of H1 will be replaced within 12 months of inspection where possible in planned work packs, alongside other assets identified for replacement.
- Crossarms with imminent insulator defects (leaning/cracking) and located within high fire risk zones are prioritised.
- Where crossarm and pole have been identified as in good condition but an insulator defect has been identified, an insulator replacement will be actioned.
- When a pole is replaced due to its condition, all associated crossarms are replaced in parallel. This represents a major driver for fleet-wide crossarm replacement.

DISPOSAL

When crossarms are removed, efforts are made to donate or repurpose them for landscaping or agricultural uses. If repurposing is not feasible, landfill disposal becomes necessary due to concerns related to the preservative used on these assets.

This approach aims to prioritise sustainable practices by promoting the reuse of materials before resorting to landfill disposal, while also addressing potential environmental and safety considerations associated with the preservative treatment.

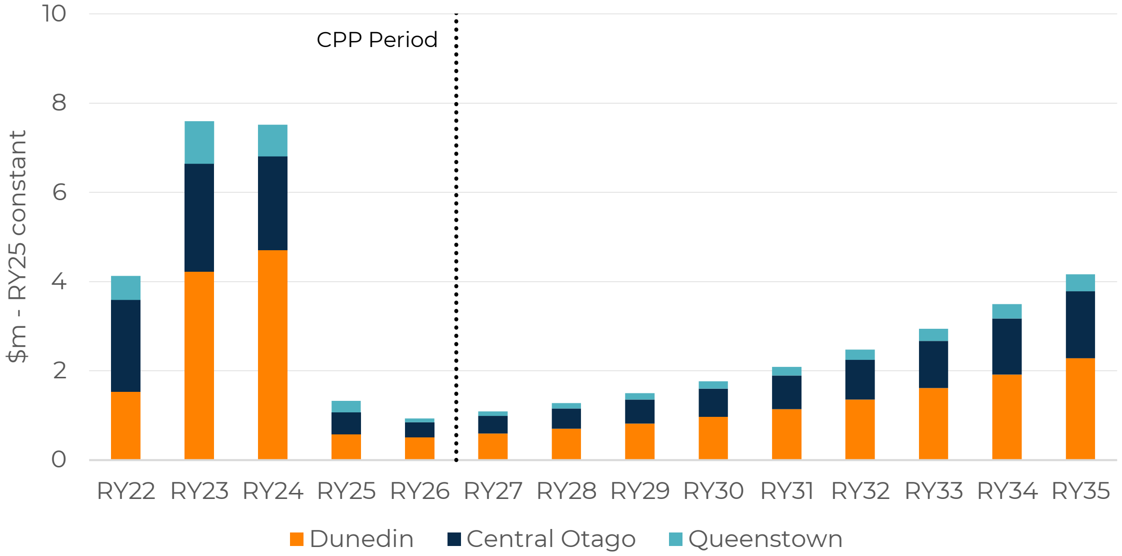
FORECAST CAPEX EXPENDITURE

Our expenditure plan has changed considerably since AMP23. There are a number of factors behind the drop in renewal planning, including:

- Limitations in the condition data obtained through the initial pole inspection programme, as detailed above, including validation through testing
- Acknowledgement that we will be much better positioned to identify priority replacements as we start to receive new information from our enhanced overhead inspection programme
- The need to create financial capacity to facilitate growth
- The fact that the plan below does not capture crossarms replaced when the pole is replaced (i.e., when the crossarm is replaced as an associated asset)

Figure 11-13 shows the predicted capex on crossarms for the forecast period.

Figure 11-13: Capex forecast crossarms by region (RY25 constant, $m)



11.4. OVERHEAD CONDUCTOR

This section describes our overhead conductor portfolio and summarises how we manage the subtransmission overhead conductor (33 kV and 66 kV), distribution HV overhead conductor (6.6 kV and 11 kV), and distribution LV overhead conductor (230 V and 400 V) asset fleets.

Our overhead conductor, in combination with support structures and their attached plant and equipment, makes up our overhead line network. This system comprises approximately 63% of our total network circuit length.

The allocation of overhead conductor into sub-fleets reflects not only the risks and criticality associated with the assets – both of which vary with voltage – but also the inherent characteristics of each voltage level.

Different combinations of these factors lead to different lifecycle strategies.

Our conductors are installed in a range of environments, from inland alpine to coastal; and in a range of different contexts, from agricultural to industrial. This gives rise to different degradation mechanisms and subsequent lifecycle management approaches.

The overhead conductor portfolio also includes conductor joints and attachment components such as binding wire and preform ties, but excludes insulators and other crossarm components.

We have 55 different types of conductor, grouped into four material types across the three conductor fleets and three sub-networks:

- **ACSR:** Steel-reinforced aluminium conductor
- **AL:** All aluminium conductor (AAC), all aluminium alloy conductor (AAAC), and aerial bunched conductor (ABC)
- **CU:** Copper conductor
- **ST:** Steel conductor

Table 11-15: Conductor fleet characteristics

	Material	Subtransmission km	Distribution HV km	Distribution LV km
Dunedin	ACSR	25.5	272.5	0.0
	AL	12.1	95.1	235.5
	CU	105.4	360.7	563.1
	ST	0	0.4	0.1
	Unknown	0.1	0.0	7.0
Central Otago & Wānaka	ACSR	293.6	1007.6	10.6
	AL	3.5	100.5	59.6
	CU	11.9	23.4	38.4
	ST	0	148.0	0.0
	Unknown	0	0.7	65.7
Queenstown	ACSR	66.3	249.9	1.4
	AL	2.0	16.9	14.1
	CU	0.2	1.5	5.6
	ST	0.0	12.7	0.0
	Unknown	0.0	0.4	23.0
Network total		**520.7**	**2290.1**	**1024.0**

Our conductor asset type data is incomplete, with approximately 90 kilometres of unknown type data predominantly on the LV network. In addition to this issue, we are finding many examples of incorrect type data.

This creates a risk in the form of either overload in operational management due to the application of incorrect conductor ratings, or incorrect health modelling – which in turn compromises our ability to ensure optimised renewal planning.

To mitigate these risks, as a new initiative from RY24, Aurora Energy's overhead inspections require inspectors to validate conductor type records. This will not realise 100% accuracy because it is not possible to visually distinguish between different aluminium materials (ACSR vs AAC, for example) and it is difficult to visually identify the difference between similar diameter conductor sizes. However, because it is easy to visually identify significant differences in diameter size or differences between conductors of different materials such as aluminium and copper, this initiative will help to reduce the risks associated with incomplete conductor asset type data.

We also expect that the implementation of an LV visibility platform will help with validation of LV conductor sizing and determination of unknown conductor types.

All conductors are site validated prior to renewal scoping to mitigate premature renewals due to incorrect data, and work is planned as part of the IBM Maximo implementation to rank the accuracy of conductor data with a view to tracking and updating all validated data.

ASSET AGE

Our oldest conductor was installed in 1907 and our newest in 2024. Figure 11-15 shows the age profile by type. Typically:

- Copper conductor was installed at all voltages from the early twentieth century through to the mid-1960s.

- ACSR conductor was installed at EHV and HV from the mid-1950s through to 2009 and is still installed when required if engineering assessment dictates.
- AAC conductor was installed at LV from the mid-1960s through to 2020.
- AAAC conductor has been installed at EHV and HV since 2009 and is still the preferred conductor for new and renewal work.
- ABC conductor was installed at LV from the 1990s and is still the preferred conductor for new and renewal work.
- Steel conductor was installed from the 1950s through to the 1980s.

Age data is used as an indicator of conductor health, enabling us to produce an AHI model.

However, there is some risk in this approach because our conductor age data is incomplete and often incorrect. We also have records where a best estimate date has been applied using the typical install periods detailed above. Further, it is not yet possible to quantify conductor age inaccuracies, so further condition evaluations are required prior to a final renewal decision.

We carried out bulk generic age updates on the HV ACSR fleet in 2023, aligning to known installation periods and improving the asset health model. A similar exercise is planned for the LV AAC fleet.

Figure 11-14 and Figure 11-15 show our conductor age profiles by operating voltage and conductor material.

Figure 11-14: Conductor age profile by operating voltage

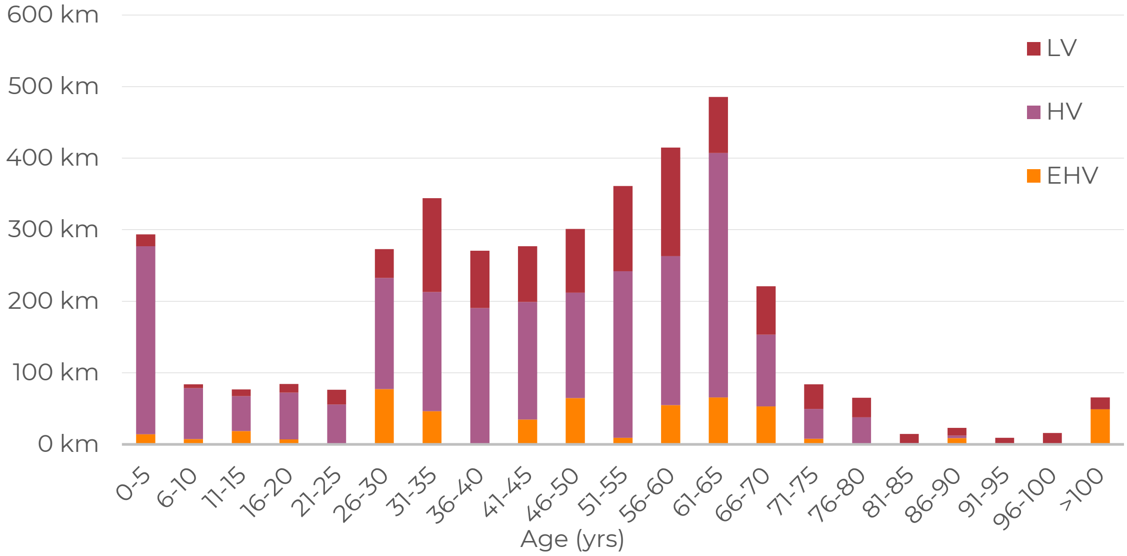
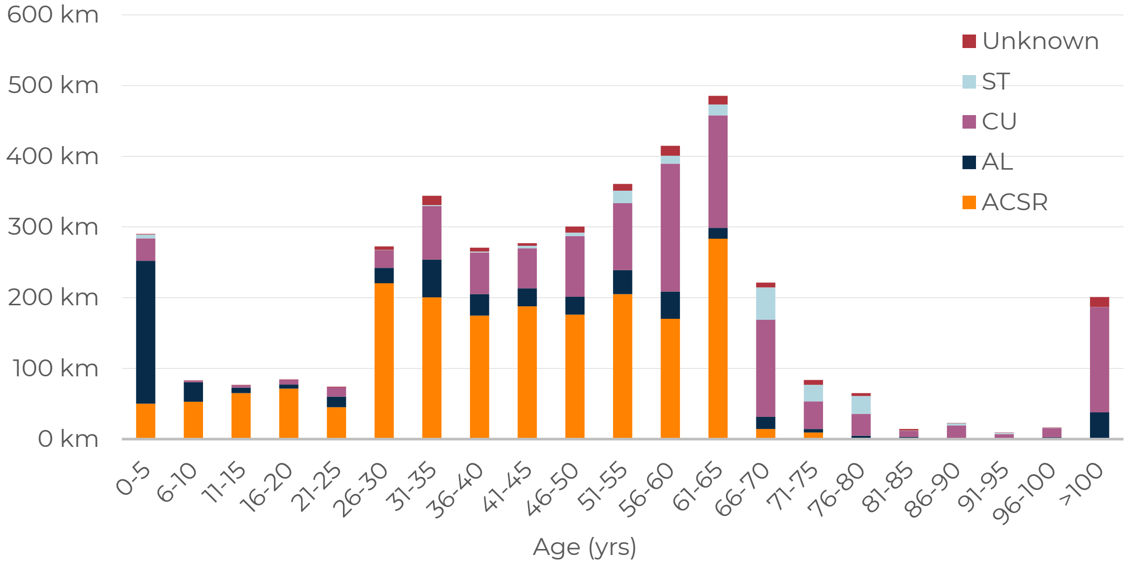


Figure 11-15: Conductor age profile by material



ASSET HEALTH

Overhead conductor condition assessment typically presents a challenge for the electricity industry. Visual observation, whether from the ground or air, gives an indication of overall asset health and enables identification of defects such as broken strands, corrosion, damage from conductor clashes, loss of insulation, bulging due to steel inner core corrosion, bird caging, and clearance violations. As part of cyclic overhead inspections, Aurora Energy now requires inspectors to grade conductor condition using a visual representation guide, with the data fed into the asset health model. The visual grading criteria are aligned to the EEA asset health indicator scale.

We use material, size, age, and location data as the primary drivers of our health model, to determine conductor life expectancies. We also factor in condition information received through inspections and testing. A recent performance evaluation of our larger copper conductors has led to a positive adjustment of the life expectancy of copper conductor in the 50 mm² to 100 mm² cross-sectional area (CSA) range.

While the life expectancies we have set out provide a good starting point and are within the bounds of good practice when compared to those used by other electrical asset owners in New Zealand, we expect to refine them as we increase our knowledge through sampling and condition assessment.

Table 11-16: Conductor expected life

		Distance from coast		
Material	CSA mm²	< 0.5 km	0.5–5 km	> 5 km
AL	< 100	77	93	110
AL	> 100	87	103	120
ACSR	< 100	48	63	84
ACSR	> 100	58	73	94
CU	< 50	55	67	80
CU	> 50	65	77	90
ST		48	59	75
Unknown		52	62	78

Our AHI model uses the material, size, age, location and visual grading from inspections to determine conductor life expectancies. Figure 11-16 to Figure 11-18 below compare the current health of the asset fleet to the projected asset health in RY35 following our planned programme of renewals, and a counterfactual 'do nothing' scenario. This comparison indicates the benefits provided by our proposed expenditure programme.

Figure 11-16: Projected EHV conductor asset health

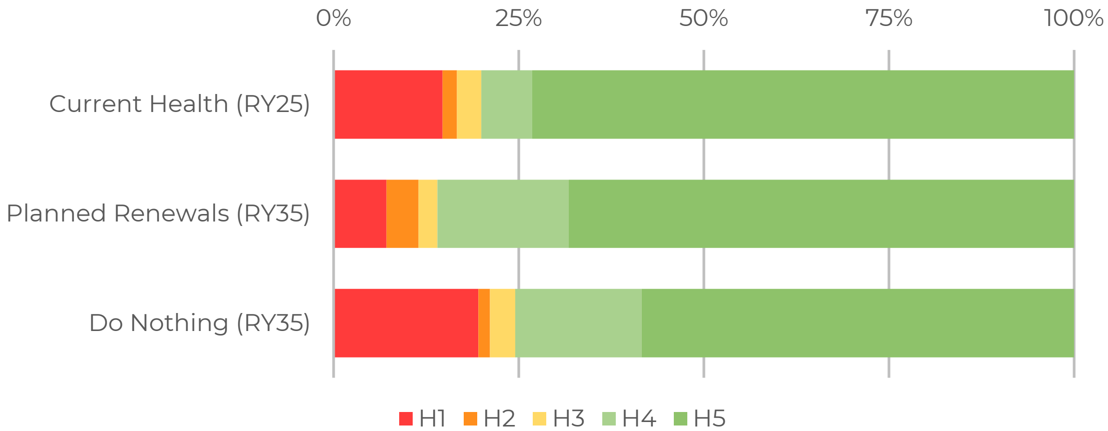


Figure 11-17: Projected HV conductor asset health

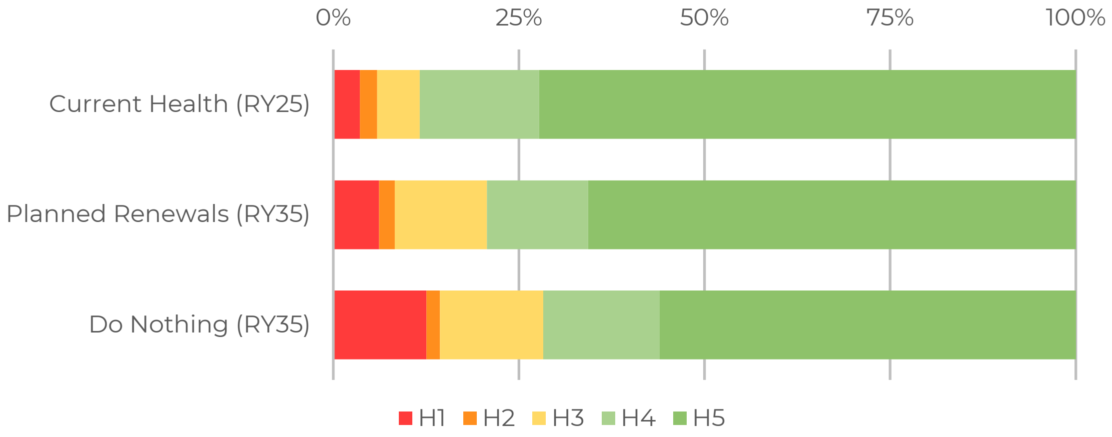
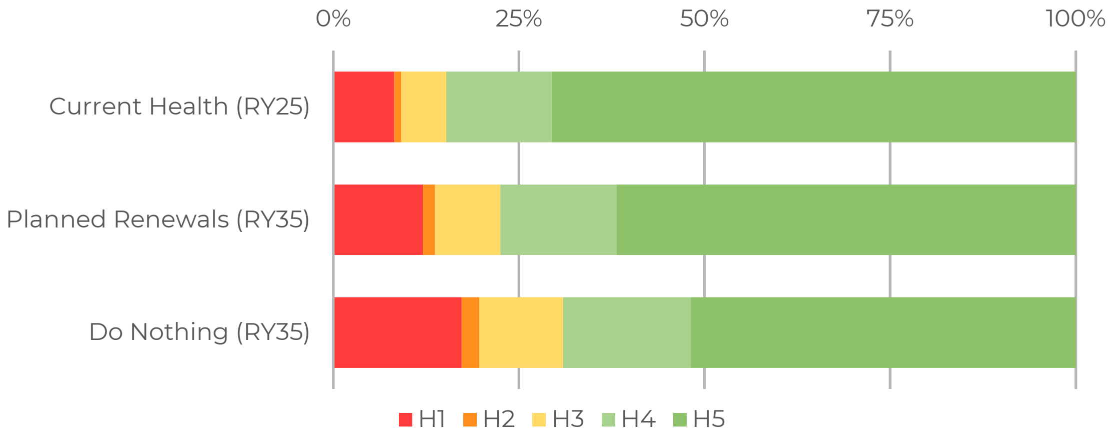


Figure 11-18: Projected LV conductor asset health



ASSET PERFORMANCE AND RISK

The table below sets out a high-level summary of the key risks and mitigations we have identified in relation to our conductor fleets. They apply to varying degrees across all voltage levels. We are managing and mitigating these risks to the extent possible, including improving our understanding of condition through sampling and destructive testing, and managing condition through our renewal programme. We are also reducing the risks associated with conductor failures by ramping up a prioritised protection replacement programme to help achieve safe de-energisation of conductors that do fail to ground.

Table 11-17: Key conductor risks and mitigations

Risk/Issue	Mitigation
Conductor failure to ground due to poor condition or workmanship issue with conductor itself or joints or fittings	New inspection regime and forensic testing regime Proactive replacement of conductor sections Proactive inspection of joints and fittings Standardisation of equipment Training and education of line mechanics on the usage and installation of joints and fittings Protection systems and prioritised electromechanical relay replacement programme RCA on failures and targeted advanced inspections in response to monitored reliability and performance, including on associated assets that may lead to conductor failure to ground incidents

Risk/Issue	Mitigation
Conductor floating due to failure of hardware such as fittings	New conductor inspection regime includes fittings. Pole and crossarm inspection regime. Proactive replacement of components where warranted. Installation of vibration damper on lines where conductor attachment method, conductor tension, and environment dictate, as per AS/NZS 7000.
Conductor overload causing sag and potential for electrocution, fire	Operating procedures, conductor validation during inspections, MDI reads, network planning, and subsequent works.
Non-compliant conductor clearance causing contact risk to people, property or livestock	Overhead line inspections or ‘ring-ins’ identifying low spans. Under-clearance remediation programme.
Conductor overheating while delivering fault current, leading to sag and clashing	Replace small conductor at risk of insufficient fault handling capability, and replace protection relays.
Conductor flashover due to bird or tree contact	Vegetation management programme: annual inspection and maintenance for all subtransmission as well as distribution feeders identified as critical. Fitting of bird diverters or falcon guards onto steel crossarms in areas of known significant presence or nesting. Introduction of insulated composite crossarms.
Third-party conductor damage	Permit processes, safety programmes, inspection regime, and subsequent remediation of under-clearances and damaged conductor.
Risk of homeowners undertaking tree trimming accidentally touching a live conductor	Safety programmes, first vegetation cuts, consumer pole and line inspection, and remediation programme.

All conductor failures are now investigated, with findings recorded in a consistent way. Unassisted failures with a root cause condition driver are reviewed against our conductor health model to ensure data accuracy.

We are actively using the information and understanding of failures and condition (sample tests undertaken on some recovered conductor) to inform renewal priorities. Currently, our assessment is that 7/.067 copper, 4SWG copper, and No. 8 steel conductors are at greatest risk of unassisted failures.

We have targeted 7/.064 copper because it is an aged, small diameter, low-strength conductor that has had multiple unassisted failures across the network (eight in the last 18 months), with investigations determining the failure mode to be corrosion fatigue. Our HV network has approximately 140 kilometres of 7/.064 copper – accounting for 6% of the total. Testing has indicated an average degradation of 26% from new ultimate tensile strength.

We have targeted 4SWG copper because it is the oldest conductor on our network. Installed in 1907, this conductor is now obsolete, which makes recovery and repairs challenging.

A small sample set of this conductor was tested, with average degradation of 14% from new ultimate tensile strength. Visual observations of this conductor have also identified under-binder fretting degradation, indicating it is likely to have higher degradation than the test results show.

Under-binder fretting has been identified by some contractors on aged copper conductors when carrying out maintenance activities on associated poles. It has also been identified on returned conductors from renewal projects. We plan to raise awareness of this failure mode/degradation with contracting staff and request intrusive inspections as part of planned work in 2025, to record any similar defects.

Destructive testing of larger diameter aged copper conductor is ongoing, focusing on sample sets at both ends of our health index ranges, to reinforce our renewal decision-making and enable us to improve our model.

No. 8 steel conductor is a small diameter, low-strength conductor often assessed as suffering from atmospheric corrosion (rust). Galvanic corrosion has also been identified, particularly at attachment points on insulators where dissimilar materials have been used for binding wire. This conductor has a high impedance and is typically installed in rural end-of-line locations, resulting in low fault current levels. This increases the risk of earth fault protection not detecting a fault and operating in the event of a line down. Adding to the issues, full tension joints on the conductor were often made in the past by wrapping the conductor back on itself, resulting in a high resistance connection.

This conductor will often elongate following bird or tree strikes or after a snow event, leading to a subsequent failure. Because this conductor was manufactured as fencing wire and not to conductor standards, a known new material strength is not defined, as the steel grade is unknown. This makes destructive testing type degradation assessments impractical.

On the HV network, we have approximately 141 kilometres of No. 8 steel conductor – accounting for 6% of our HV conductor. There has been one unassisted failure in the previous 18 months, with investigation determining corrosion fatigue as the failure mode.

Failure of overhead conductor can also be caused by factors unrelated to the conductor's condition. Tree and third-party machinery strikes are common, resulting in either downed lines or conductor damage.

Failures of line components such as insulators or joints and connections are common and result in downed lines or conductor damage.

Through RCA, we are establishing a more robust process to ensure the correct cause is established – thereby enabling us to trend causes rather than just numbers of failures, so we can respond effectively to the associated risk of 'unassisted' failures. We are also actively managing and seeking improvements in how we manage vegetation risk. Refer to Section 11.2.5 for more on this. With respect to strikes, we have proactive communication strategies in place.

Findings from the RCA process have identified an unacceptable number of downed lines from failed full-tension pre-formed line splices: nine in 18 months. Cyclic overhead inspections capture the locations and type data of HV and EHV joints and connections, while thermography carried out in the inspections has identified some at immediate risk, thus enabling appropriate intervention.

We are now considering proactive replacement of preformed splices with full-tension compressions as a maintenance activity following feeder inspections. Risk and cost will inform this decision.

REPLACEMENT/RENEWAL

At present, we identify renewal candidates by using age and expected life as a proxy for condition. As previously mentioned, we validate data and use inspections and testing of samples of conductor to continually adjust or validate remaining life expectancies. Our current programme is driven by the above parameters, informed by criticality and deliverability.

As described above, our current assessment of fleet health is somewhat constrained, but clearly signals a backlog of conductor that has exceeded its expected life.

Through the overhead inspection programme rolled out in 2023, we are actively gathering more data to enable enhanced predictive analysis and forecasting, and we will review and update our forecasts as the benefits of the programme are realised. We are also actively maturing our understanding of asset performance by applying RCA to all failures.

We will review and update our forecasts as the benefits of the new overhead inspection programme are realised. Our current programme is informed by and focused on known issues related to type, age, and exposure, prioritised using our safety criticality zones.

When planning the replacement of conductor, it is a requirement to consider and assess:

- The new conductor sizing requirement, factoring in existing load and network augmentation
- Ongoing requirement for the line and other solutions
- The health of associated assets and whether earlier than planned replacement of such assets will be more cost effective and less disruptive
- Existing route and ongoing suitability, factoring in environmental and other risks

RENEWAL PRIORITIES

SUBTRANSMISSION LINES

We have identified three subtransmission lines that require reconductoring in the near term in Dunedin, as well as one line and a section of a second in the Central Otago region. The renewal of the Waipori A, B, and C lines, as discussed above, comprises a multi-stage, multi-year plan, of which one stage has been completed. These projects can require significant expenditure, so it is important to carefully evaluate options to maximise opportunities to enhance future network performance and reliability.

HV DISTRIBUTION

Of our distribution HV conductor, approximately 12% is nearing replacement criteria, as described above. We are prioritising No. 8 steel and 7/.064 copper for renewal, by criticality zone.

LV DISTRIBUTION

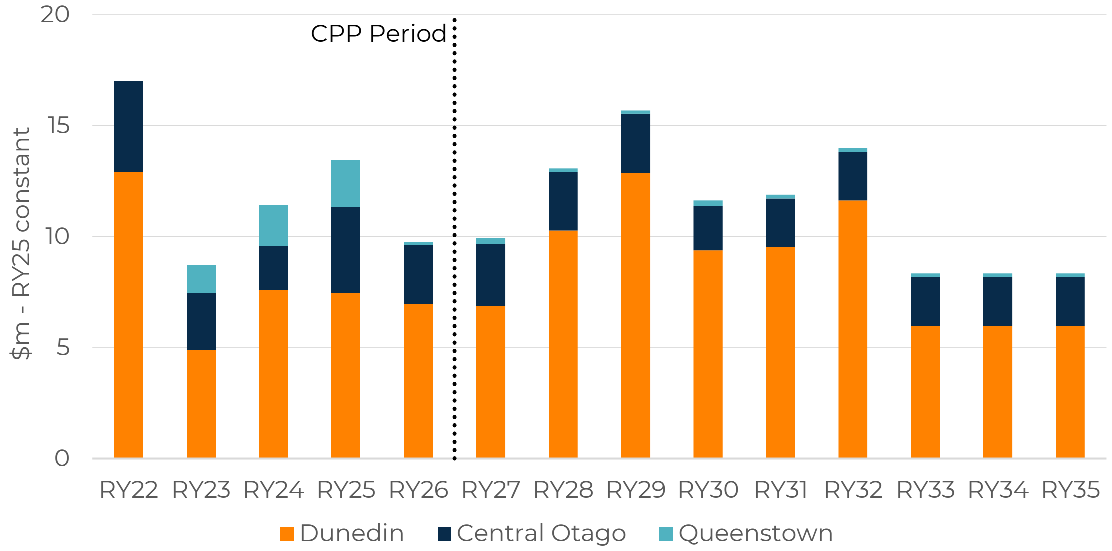
Of our distribution LV conductor, approximately 21% is nearing the same replacement criteria. We are targeting small-diameter low-strength LV conductor such as 7/.064 and 19/.052 copper for renewal. To realise cost and interruption efficiencies, we are prioritising conductors that are showing signs of insulation loss or that are underbuilt on HV lines.

DISPOSAL

Aside from growth projects, conductor replacement is generally based on condition. As such, the conductor is generally degraded to the point where reuse is not an option. When replacing conductor assets, we scrap the degraded material with the expectation that the material will be recycled. Historically, second-hand conductor has been used on our network, but at present we have no reason or opportunity to continue this practice.

FORECAST CAPEX EXPENDITURE

Figure 11-19: Capex forecast overhead conductor by region (RY25 constant, $,000s)



Our forecast for subtransmission conductor has changed from AMP24 to AMP25: an increase of $8.23m over the period RY26–RY30. The key reasoning for this adjustment is:

- Timing supported by learnings from RCA
- Increasing capacity/voltage requirements for subtransmission lines (new lines require larger conductor)
- Recategorization of the Meg re-conductor work as a lifecycle driver, following option analysis of proposed Upper Clutha solutions
- Bringing the staged replacement of the Waipori lines forward one year
- Increased cost of major subtransmission renewal projects

Note that due to the timing and planning requirements for larger renewal projects, the short-term view (RY26–RY30) fails to capture the medium-term renewal needs, which will require increased focus and resources.

11.5. UNDERGROUND CABLES

This section describes our cable portfolio and summarises how we manage our fleets of subtransmission cables, distribution cables, and low voltage cables.

Cables are a key component of our network, providing the electrical interconnection between assets to safely supply electricity to consumer connections. Conveying electricity between the transmission system, zone and distribution substations, and LV customers, our underground cables come in a variety of types and sizes, enabling electrical flow at various voltages. This portfolio also encompasses cable joints, pole terminations, equipment terminations, and other ancillary cable equipment.

We define our underground cable fleets according to operating voltage. This is because the approach needs to reflect not only the risks faced and the criticality of the asset – both of which vary with voltage – but also the inherent nature of each voltage level.

Within the subtransmission fleet in the Dunedin region, we have fluid-filled insulated cables (gas or oil) and solid insulated cable incorporating paper or XLPE insulation, whereas in the Central Otago & Wānaka and Queenstown regions, the subtransmission fleet is solely XLPE-insulated.

Within our distribution cable fleet, the majority of our PILC distribution cable is in the Dunedin region. PILC cable ceased to be the standard cable used in the Dunedin region in the 2000s, while XLPE was adopted earlier in the Central Otago & Wānaka and Queenstown regions by the previous network owners. As such, the majority of our XLPE distribution cable is in the Central Otago & Wānaka and Queenstown regions.

Within our low voltage cable fleet, there is a wide mix of cable types. Table 11-18 summarises the underground cable fleet by type, voltage, and sub-network.

Table 11-18: Underground cable fleet characteristics

	Material	Subtransmission km	Distribution HV km	Distribution LV km
Dunedin	Gas-filled	16.1	0.0	0.0
	Oil-filled	26.6	0.0	0.0
	PILC	8.2	271.3	34.5
	XLPE	16.7	61.0	284.9
	PVC	0.0	0.0	0.0
Central Otago & Wānaka	Gas-filled	0.0	0.0	0.0
	Oil-filled	0.0	0.0	0.0
	PILC	0.1	57.3	1.4
	XLPE	8.9	545.0	525.9
	PVC	0.0	0.0	0.0
Queenstown	Gas-filled	0.0	0.0	0.0
	Oil-filled	0.0	0.0	0.0
	PILC	0.0	80.1	2.1
	XLPE	25.2	217.5	319.5
	PVC	0.0	0.0	0.0
Network total		**101.7**	**1232.2**	**1168.4**

ASSET AGE

Cable has been installed on our network since 1914, with the type of cable changing as technology developed. Based on existing in-service cables, typically:

- Gas-filled cable was installed on subtransmission voltages from 1963 to 1967. It is no longer installed, as the technology requires additional assets to maintain and monitor the gas pressure, there is a risk of gas leaks that can degrade insulation levels, and gas has been superseded by new insulation materials. Gas-filled cable has an expected life of 100 years.
- Oil-filled cable was installed on subtransmission voltages from 1972 to 1980. It is no longer installed, as the technology requires additional assets to maintain and

monitor the oil pressure, there is a risk of oil leaks that can degrade insulation levels and impact the environment, and oil has been superseded by new insulation materials. Oil-filled cable has an expected life of 100 years.

- Paper-insulated lead-covered (PILC) cables were installed from 1938 to 2019. They are widely used across all network voltages. They are presently only installed in specific circumstances where XLPE cannot be used, and have an expected life of 80 years.
- XLPE is the current standard cable type used by Aurora Energy. It has been installed since the early 1980s and can be used across all network voltages. It has an expected life of 60 years.
- PVC cable has been used on the network since 1914 – most commonly on the LV network. It has an expected life of 60 years.

Figure 11-20 shows our subtransmission cable age profile. The young population of XLPE subtransmission cable reflects the growth in the Central Otago & Wānaka and Queenstown regions over the last 20 years in combination with the commencement of cable replacements in Dunedin with XLPE technology.

Figure 11-20: Subtransmission cable age profile

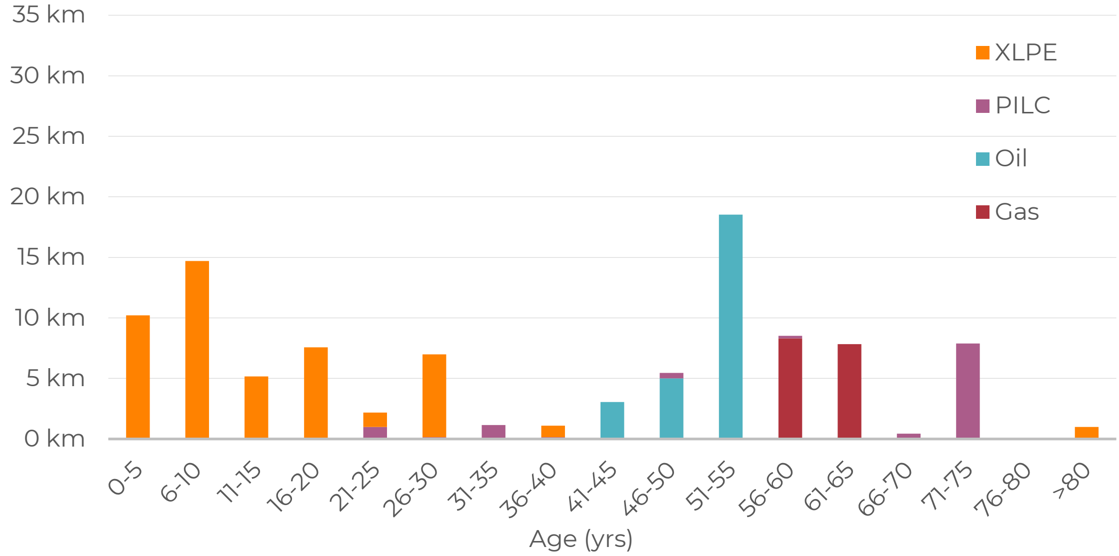


Figure 11-21 shows our distribution cable age profile. Our distribution cable fleet is considerably younger than our subtransmission cable. The young population of XLPE distribution cable reflects the large growth in new connections in the Central Otago & Wānaka and Queenstown regions over the last 20 years.

Figure 11-21: Distribution cable age profile

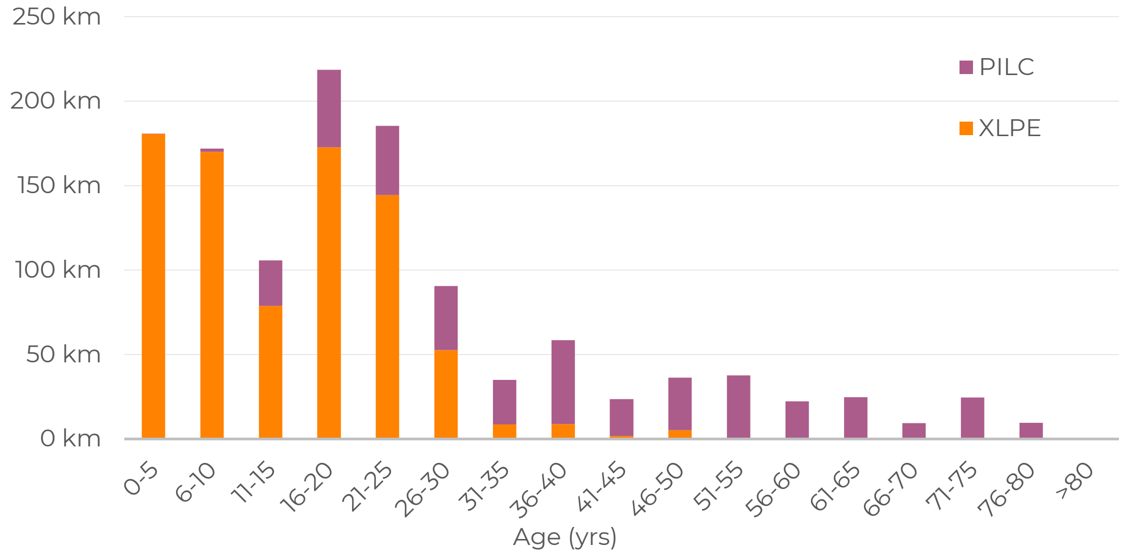
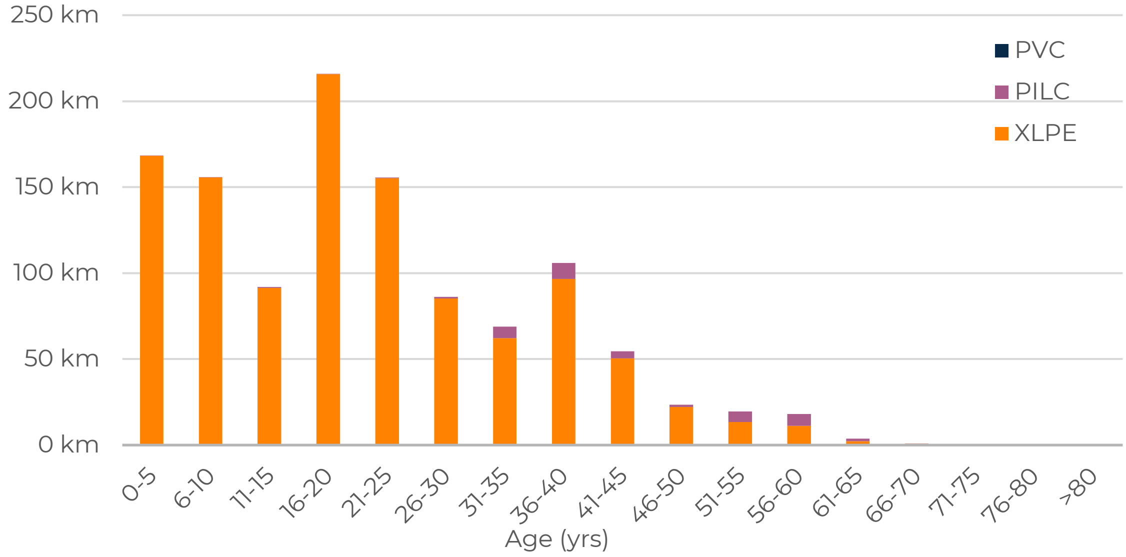


Figure 11-22 depicts our LV cable age profile. Our LV cable fleet is relatively young, much of it reflecting network growth over the past 20 years.

Figure 11-22: LV cable age profile



ASSET HEALTH

Our subtransmission cables are generally in serviceable condition and none of these cables will exceed their maximum practical life as defined in the EEA AHI Guide within the next 10-year planning period. However, there are some type-related issues that are resulting in accelerated deterioration.

We have observed gas leaks on some of our remaining gas-filled cables. Leaks are caused by cable movement and corrosion of the bronze tapes that hold the lead sheath in place or punctures and deterioration of the outer sheath. This allows moisture ingress, which causes further degradation. Gas leaks are difficult and costly to locate and repair.

The condition of the sheaths of our oil-filled cables is generally acceptable, although some minor leaks present a concern.

Our older solid PILC subtransmission cables have suffered accelerated deterioration due to drying out of the paper where the cable is installed on steep slopes. This has caused several faults, and though they have not quite reached their expected life, we plan to replace the affected cables in the near-term. All other PILC and XLPE cables are considered to be in serviceable condition.

The health of our cable portfolio is informed by condition, as well as non-condition parameters in the form of age and criticality. Figure 11-23 to Figure 11-25 show the AHI of our cables by fleet. Where we have known failure or fault occurrences and known issues with the original design, the condition factors are prominent. However, for other cables we are reliant on age-based health models for forecasting. Our AHI modelling is a hybrid of condition and age that requires more development, as the progression into H1 at the later timeframe of the plan is dominated by age, which produces an overly conservative accelerated AHI decline.

We have done some work to revise the model and exclude non-condition end-of-life (EOL) drivers from the AHI model, such as obsolescence. At present, the model does not yet accurately reflect the need to replace some cables, as the renewal of some cables is being driven by emerging failure trends, uncertainty of failure, and the impact of failure. Concerns over the ongoing cost of repairs and the environmental impact of failure of fluid-filled cables are also driving renewal of the cables, but these issues have not been captured in the AHI model. As we mature our model, we are refining how we capture emerging failure trends to better reflect the health of the fleet.

Our model for subtransmission cables indicates that when the three identified priority projects (discussed in Renewal Priorities, below) have been completed, the overall health profile is improved, while of course some age-based deterioration is inferred.

As discussed in Renewal Priorities, renewals are mostly reactive for distribution and LV cables. This is aligned to our commitment to investing in Safety First. In addition, renewal of distribution and LV cables has a lower impact on reliability; and as a result, investing in this fleet has not yet been a priority.

Figure 11-23: Projected subtransmission cable asset health

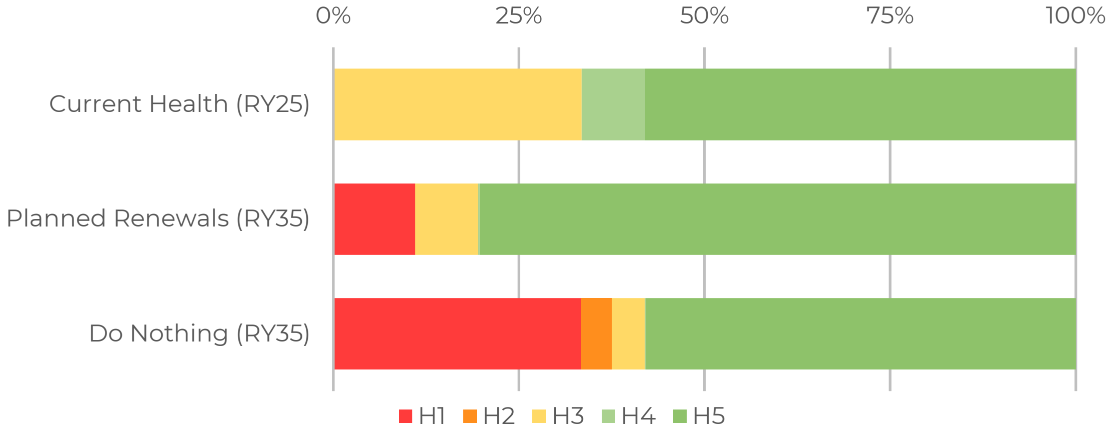


Figure 11-24: Projected distribution cable asset health

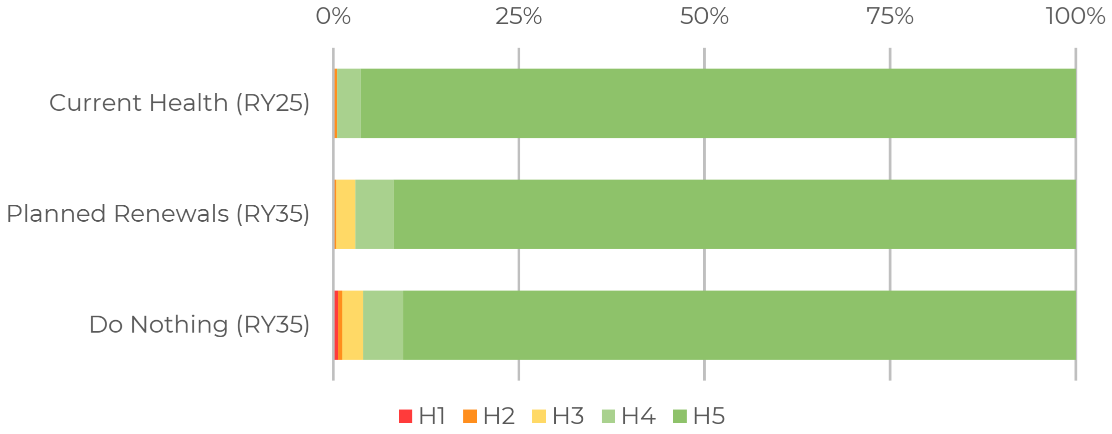
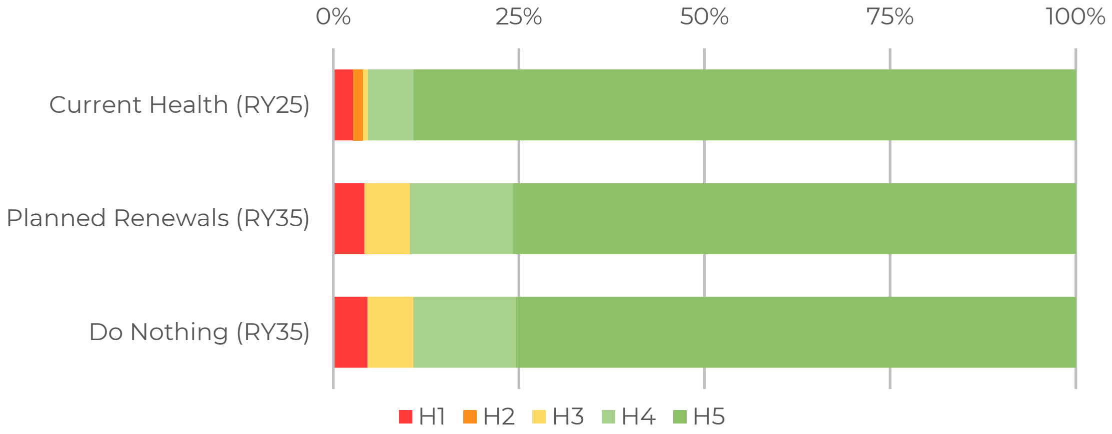


Figure 11-25: Projected low voltage cable asset health



ASSET PERFORMANCE AND RISK

Because asset performance and risk apply generally across all of our underground cable fleets, they are discussed at a portfolio level in this section. Table 11-19 sets out the key risks and mitigations we have identified in relation to our cable portfolio.

Table 11-19: Key cable risks and mitigations

Risk/Issue	Mitigation
Cable strike	The beforeUdig service Strategic spare cable joint kits N–1 redundancy in subtransmission installations Cable differential protection is fast and limits damage
Partial discharge	Periodic on-line partial discharge monitoring to detect failing insulation
Oil-filled cable leaks: Oil cables have an emerging failure mode of accessories (joints/terminations) leaking oil (wipes and pipework across joints) For example, CO1 & CO2 are the most complex oil cable runs (joint types/along route pressure tanks) due to elevation change over the cable route	Oil pressure monitoring via SCADA and routine site inspections Oil in cables is not considered a hazard by the Regional Council
Gas-filled cable leaks: For example, WB1 & WB2 gas cables have an emerging failure mode of sheath gas leaks	Gas pressure monitoring via SCADA and routine site inspections
Lack of resilience to major events (e.g. seismic activity)	Some intertie capacity at distribution voltage level and a limited capacity 33 kV link between Ward St and Carisbrook zone substations Dunedin subtransmission architecture changes will lead to diverse cable routes via a ring architecture, and hence a reduction of common mode failures
Fault due to PILC cable drying out: For example, KV1 & KV2 early vintage solid cables have design type issues (migrating grease - dry paper - hotspots) due to elevation change over the cable route	Cable differential protection is fast and limits cable damage N–1 redundancy in subtransmission installations Factored into subtransmission cable replacement programme
Oil/grease leakage at joints/pot-heads: (due to cable laid with high head)	Routine site inspections
Water treeing leading to insulation failure: 1st Gen XLPE known to have the potential to develop water treeing leading to insulation failure due to materials and construction methods	Ongoing condition-monitoring and risk-based renewal prioritisation
Obsolescence of fluid-filled subtransmission cables: Spare parts are challenging to obtain, with lengthy lead-times Lack/loss of technical knowledge in the business resulting in a reliance on external resources Lack of storage space hinders management of strategic spares	Policy of buying spares at the time of procuring cable and replacement of spares when used, to maintain strategic stock levels Managing competency requirements regarding contractors and subcontractors As part of the development of our spares strategy, we are evaluating storage requirements and options

REPLACEMENT/RENEWAL

At present, we identify renewal candidates by using age and expected life as a proxy for condition and augment this with condition information where available.

Where we identify defects that are uneconomic to repair, they are scheduled for replacement and prioritised based on risk and deliverability.

When planning the replacement of cable, it is a requirement to consider and assess:

- The new cable sizing requirement, factoring in existing load and network augmentation
- Ongoing requirement for the cable and other solutions
- The health of associated assets and whether earlier than planned replacement

of such assets will be more cost-effective and less disruptive

- Existing route and ongoing suitability, factoring in environmental, ground composition (i.e., slope, rock content), and other risks as well as cable material type

RENEWAL PRIORITIES

The renewal strategy as detailed above for subtransmission cable provides a prioritised renewals strategy that starts with condition-based and steps through to non-condition-based drivers (spare parts, obsolescence, workforce skills), age, and then all gas and oil cables, accounting for delivery of the Dunedin Subtransmission Project.

SUBTRANSMISSION CABLE END-OF-LIFE REPLACEMENT

The current renewal strategy is to renew the subtransmission network to address the increasing risk to network reliability and security. Where cables cannot be replaced on the existing route, an alternative route will be identified – or an alternative network reconfiguration may be required – and the existing cable will be made safe and abandoned. This will address all gas and oil-filled cables as well as the vintage PILC cables identified as having dried out resulting in accelerated end-of-life.

DUNEDIN SUBTRANSMISSION PROJECT

The Dunedin Subtransmission Project will reconfigure the subtransmission network in Dunedin to address deteriorated cables and concurrently improve network security. The project considers – but is not limited to – renewals. We are working on a common timeline to coordinate the overall project outcome.

DISTRIBUTION AND LV CABLE

Our renewal programme for distribution and low voltage cables is currently predominately reactive based on inspection results and outages. Upon receipt of a failed test or inspection or in response to a fault, the cable – or a section of it – is scheduled for replacement.

CAST IRON POT HEADS (CIPH)

Prior to the early 1990s, cast iron cable terminations were used to break out PILC cable terminations up poles. In response to an alert regarding the potential for high energy failures of cast iron cable terminations, we have taken the decision to remove all of these items from our network.

As such, all CIPH assets are considered an intolerable risk and we classify them as a separate sub-fleet within our underground cable portfolio. Accordingly, we have developed a dedicated programme for cast iron cable termination replacement.

A triage activity undertaken at the beginning of the programme prioritised the removal of units in high criticality locations, such as near schools or high population density areas. Work undertaken on assets having a direct impact on cast iron cable terminations automatically triggers removal of these items.

Replacement of a CIPH is often not straightforward and commonly requires replacement of extended lengths of cable, the pole the CIPH is attached to, or other associated assets. This impacts the time, complexity, and cost of each replacement.

We are always exploring efficiencies in the form of consolidated work packages that bundle drivers of many projects according to outage zones, to minimise the cost and reduce customer impact due to the required outage to replace CIPHs.

To date, we have replaced or removed 325 units. A further 56 units remain in service and we plan to complete their removal in RY26.

DISPOSAL

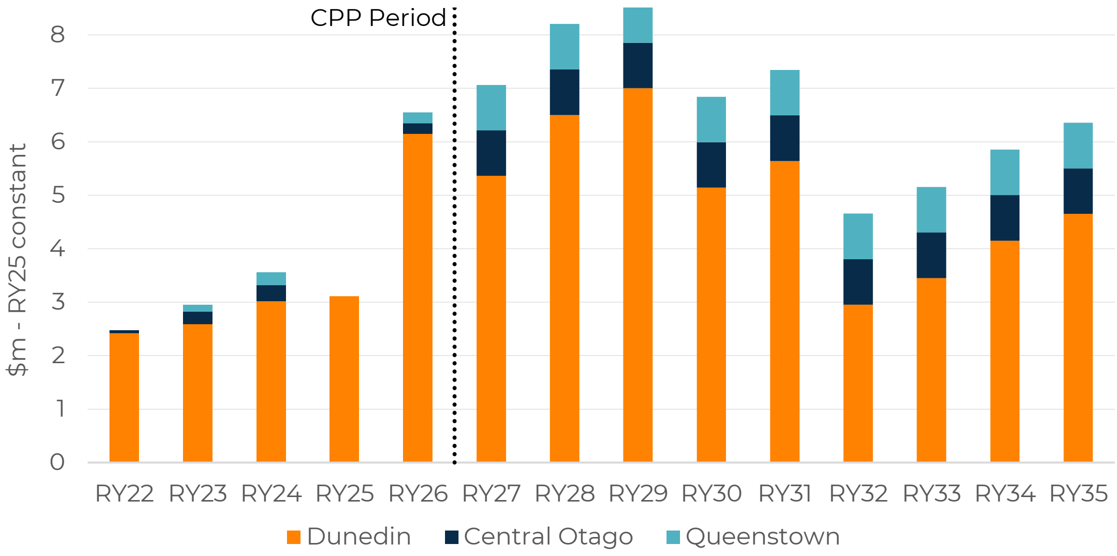
Typically, when a cable is abandoned, only the above-ground sections are recovered, while the below-ground sections are made safe at the point where they are severed, where they enter the ground, by fitting a cap and burying the cable tail.

Where the cable is an oil or gas-filled cable, the oil or gas is extracted from the cable and either recycled or disposed of.

Recovered cable is then collected by third-party scrap dealers for processing.

FORECAST CAPEX EXPENDITURE

Figure 11-26: Capex forecast underground cables by region (RY25 constant, $m)



From AMP24 to AMP25, our forecast expenditure on subtransmission cables in the period RY26 to RY30 has increased by $11.5 million.

Key considerations in making these adjustments are as follows.

- An updated health forecast reflecting an emerging trend of failures and changes to how obsolescence is treated in the modelling (while the health of this fleet appears considerably better than some other fleets, the level of expense required to replace subtransmission cables is significant). We have known issues with a small number of cables and a targeted renewal plan.
- A maturing view regarding project scope and costs as a result of feasibility studies both completed and ongoing. We will be focusing on extending our cost estimation process for major projects to incorporate subtransmission cables, and we expect that once feasibility studies and route options are fully explored, we will need to flex our plan.
- An increase in the cost of the Kaikorai Valley cable renewal project owing to options around route (urban setting).

Note that due to the timing and planning requirements for larger renewal projects, the short-term view (RY26–RY30) fails to capture the medium-term renewal needs, which will require increased focus and resources.

11.6. ZONE SUBSTATIONS

This section describes our zone substation portfolio, which comprises the following asset fleets:

- Buildings and grounds
- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Ancillary equipment

Zone substations take supply from GXPs via subtransmission feeders (both overhead and underground cable). They provide connection points between subtransmission circuits, step down voltage through power transformers to distribution voltage levels, and incorporate switching and isolation equipment to enable operation of the network.

The zone substations portfolio also includes some primary plant equipment installed at GXPs including ripple plants and outdoor switchgear, and a mobile zone substation.

Supply for many thousands of consumers depends on key assets within zone substations, making them high-value, critical assets and necessitating prudent management to ensure safe and reliable operation. Since the assets vary significantly between fleets in this portfolio, ranging from buildings to transformers and switchgear, different lifecycle management approaches are required for each. Figure 11-27 shows one of our modern zone substations.

Figure 11-27: Andersons Bay zone substation

We also own and operate a mobile zone substation, which reduces or eliminates the need for lengthy planned outages and also provides contingency coverage in the event of a major failure. This asset comprises a 5 MVA, 66–33 kV/11–6.6 kV transformer, 66 kV and 11 kV circuit breakers, and a control room with control and protection equipment.

11.6.1. Buildings and grounds fleet

Our building and grounds fleet includes zone substation buildings, fences, driveways, security, and site access-ways. We have 37 substation buildings across Dunedin and Central Otago, with building types varying widely due to a number of factors, including location (i.e. rural vs urban), size, and historical construction methodologies. Some of our smaller zone substation sites in the Central region do not have buildings but do have fencing and earthing.

Our zone substation buildings mainly house protection and communications equipment, indoor switchgear, and ripple injection plants. Buildings and grounds must provide security for the equipment they contain, be well secured against seismic risk, and be adequately earthed.

Table 11-20 summarises our population of zone substation buildings by network location.

Table 11-20: Zone substation buildings by sub-network

SUB-NETWORK	POPULATION
Dunedin	21
Central Otago & Wānaka	11
Queenstown	5
Total	**36**

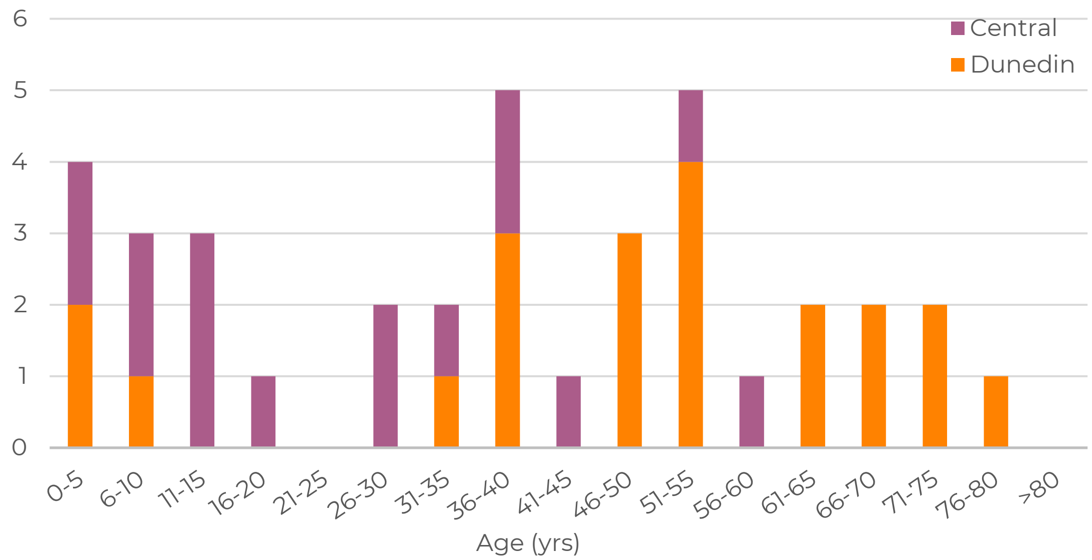
We have undertaken a seismic survey of our zone substation buildings to identify buildings that required strengthening to meet the New Zealand Building Code, and work to address the issues identified is now complete.

ASSET AGE

Our zone substation buildings range from new to over 70 years old, with an average age of 37 years. A significant number of them were built between 1950 and 1970, and the buildings in the Dunedin region have a higher average age (49 years) than those in our Central region (24 years). Our oldest substation building, located at Ward Street substation in Dunedin, is 78 years old and the newest, at Andersons Bay substation in Dunedin, was built in 2023. We are currently rebuilding the Smith zone substation switchroom, with the expectation that this will be completed at the end of RY25.

Figure 11-28 depicts the age profile of our zone substation buildings by region.

Figure 11-28: Zone substation buildings age profile (by region)



ASSET HEALTH

We use a periodic inspection programme to assess the condition of our buildings and grounds fleet. From the routine visual inspections, we determine whether there are any defects and prioritise their resolution depending on the risks they present. We respond to any public safety and security issues promptly. We do not presently have an asset health model or criticality framework for our buildings and grounds, but we will continue to refine our methods of assessing the condition of these assets and consider whether there would be value in developing an AHI and criticality framework for this fleet in the future.

Historically, our zone substation buildings have suffered from a lack of maintenance. During RY20 we started a programme of remediating building defects through activities such as painting external cladding to prevent degradation of building materials and replacing failed butanol roof coverings to prevent further water ingress. Further corrective work of this type will be required to ensure our buildings do not degrade to the point where more costly remediation is needed. We generally aim to maintain our buildings in perpetuity, the exception being where zone substation asset renewals (for example, indoor switchgear) require the building to be replaced.

ASSET PERFORMANCE AND RISK

Table 11-21 summarises the key risks identified in relation to our buildings and grounds fleet and their associated mitigations.

Table 11-21: Key zone substation buildings and grounds risks and mitigations

Risk/Issue	Mitigation
Seismic event	Completed programme of structurally strengthening buildings to 100% of NBS for the IL3 standard and upgrading internal/external equipment hold-downs
Flooding event	Elevating equipment above certain flood criteria as it is renewed; managing and upgrading stormwater management systems
Security breach	Security alarms and cameras; suitable fencing
Fire event	Fire detectors, alarms and extinguishers; fire consequence mitigation in design
Poor internal building environment leads to primary asset or electronics failure	Heat pump and insulation retrofits where practical Internal equipment anti-condensation heaters Replacement of buildings when unsuitable for new equipment
Step or touch potential leading to injury	Earthing of equipment Periodic earth grid testing Equipment inspections
Asbestos inhalation	Asbestos survey undertaken Asbestos register Hazards identified and labelled Containment or removal Specialist contractors

REPLACEMENT/RENEWAL

Renewal of buildings is often undertaken as part of an indoor switchgear renewal project and is driven by the need for seismic upgrades or physical space to accommodate new equipment. We also consider the risks, future-proofing requirements, and costs associated with reusing existing buildings or land to accommodate new equipment.

DISPOSALŌ

Buildings that are no longer required for their original purpose may be demolished or re-purposed, dependent on site-specific factors and ongoing maintenance costs. Asbestos in buildings being demolished is identified, handled, and disposed of appropriately.

11.6.2. Power transformer fleet

Power transformers are used to convert the electricity supply from one voltage level to another. These units are generally equipped with on-load tap-changers to assist with regulating the required distribution supply voltage. Our power transformer fleet includes 69 power transformers ranging from 2 MVA to 30 MVA and typically have winding voltages of 33/6.6 kV, 33/11 kV, and 66/11 kV.

Typically, large zone substations have two power transformers, providing N−1 security. Modern designs incorporate interception bunds to contain oil spills, as well as firewalls between the transformers (where necessary), to minimise the risk of fire spreading in the event of catastrophic failure.

While we now purchase standard power transformer sizes and configurations, we still have some legacy sizes; and most legacy designs are bespoke. This inclusion of non-standard models presents challenges to interchangeability and operational flexibility. Our newer power transformers are equipped with VACUTAP type tap-changers as we progressively replace the OILTAP type tap-changers, which have more maintenance requirements.

Figure 11-29: Power transformer

Table 11-22 summarises the population of our power transformer fleet by operating voltage and size.

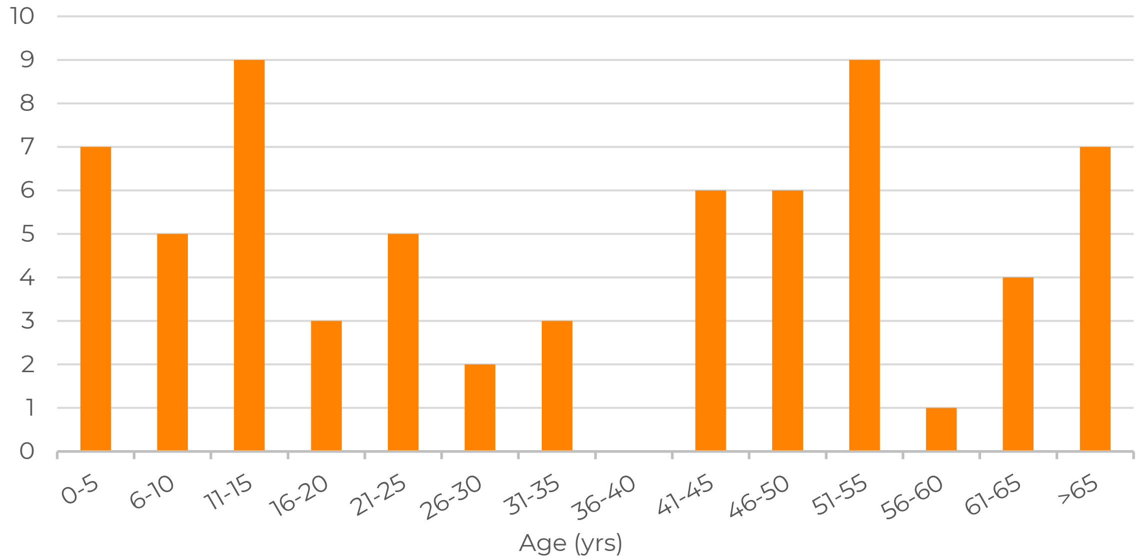
Table 11-22: Power transformer population by operating voltage and size

Highest Operating Voltage	Size (MVA)	Tap-changer Type	Dunedin	Central Otago & Wānaka	Queenstown
33 kV	≤10	OILTAP	2	4	8
		VACUTAP	2	2	1
	>10	OILTAP	24	2	2
		VACUTAP	6	5	3
66 kV	≤10	OILTAP	0	3	0
		VACUTAP	0	0	0
	>10	OILTAP	0	2	0
		VACUTAP	0	3	0
Total			**34**	**21**	**14**

ASSET AGE

As indicated by the age profile shown in **Figure 11-30**, the power transformers in the fleet range from new to 69 years old; however, renewals have reduced the average age to 35 years. Twelve of our power transformers have exceeded the average life expectancy of 60 years of age. While age is important, we also consider transformer condition to inform our maintenance and renewal programmes.

Figure 11-30: Power transformer age profile



ASSET HEALTH

Our routine testing and inspection programmes help us understand how our power transformers are ageing and help us identify any systemic issues.

The health of our power transformers, which is also the asset's stage within its overall lifecycle, is informed by an analysis of measured condition parameters. To determine the AHI of power transformers, we use a weighted average of scores derived from the following condition parameters:

- **Insulation paper condition.** The *degree of polymerisation* (DP) value measures the condition of the paper insulation and is one of the key condition metrics. A DP value of over 1000 indicates new insulation and a value of 200 indicates end-of-life. Oil sample analysis provides indirect evidence of the internal condition of the transformer, including when there has been arcing, overheating, and deterioration of the internal paper insulation. Our fleet shows no major signs of these modes of deterioration, although we have four transformers with DP values below 500, indicating they are approaching the end of their serviceable lives. Periodic use of online oil filtration has helped control moisture levels in our transformer fleet, which reduces the rate of internal deterioration.
- **Number of tap-changer operations.** Each tap-changer is designed with a lifespan – generally based on the number of operations – which determines when components such as contacts need to be replaced, as well as when the tap-changer needs to be refurbished.
- **Electrical test results.** Electrical testing also provides an insight into the condition of a transformer. The results are used for trend analysis and demonstrate that currently there are no significant or systemic issues with our transformer fleet.

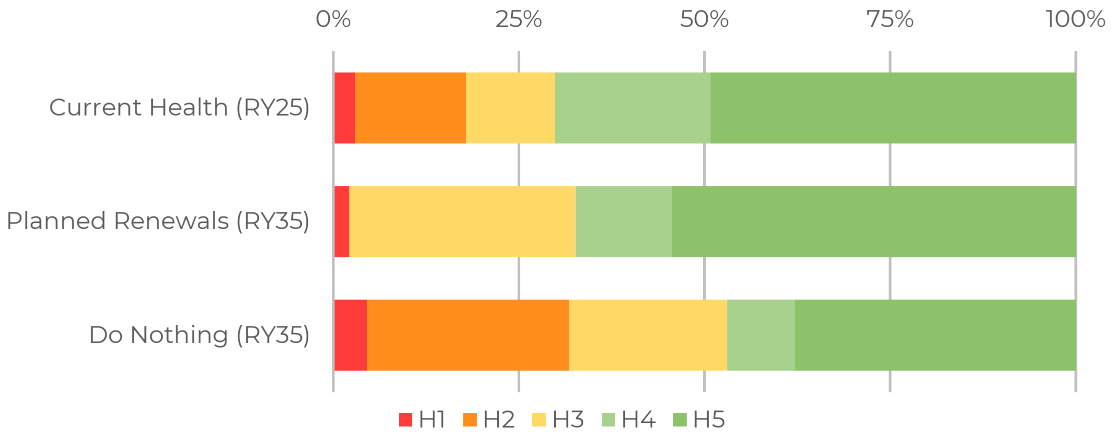
As Figure 11-31 indicates, our health forecast shows a reduction in H1, H2, and H3 transformers over the planning period, due to the asset renewal plan. As we mature our understanding and management of asset risk, we will continue to refine our methods of assessing asset health.

We aim to further develop our framework to incorporate other condition EOL drivers such as visual inspections of the main tank, the radiators, the tap-changer mechanism, and the condition of the transformer based on electrical tests, as well as non-condition EOL factors such as obsolescence, noise, and maintainability (access to personnel with the necessary skills to carry out maintenance work, availability of spares, etc.).

The external condition of the fleet is assessed through visual inspection and encompasses degree of rust and oil leaks, corrosion, lack of signage, and improper earthing. The condition of the fleet is in line with expectations based on the various models, ages, and locations. There are issues that need attending to in this regard, but none that constitute an imminent failure concern or which represent a systemic issue.

Our power transformer fleet is ageing and the likelihood of asset failure is increasing. Even with planned expenditure, the health of this fleet will continue to decline over the period. This is reflected in our current asset health, as shown below, where approximately 36% (H1–H3) will be considered for replacement during the planning period.

Figure 11-31: Projected power transformer asset health



ASSET PERFORMANCE AND RISK

Power transformers are high value, high criticality assets. The failure of a transformer can result in widespread outages or put the network into a less secure condition for an extended period of time. Hence, we monitor and manage them carefully.

Overall, our power transformer fleet is performing well and major power transformer failures are relatively rare. The main causes of major failures are defects within the core and windings, as well as on-load tap-changer (OLTC) failures, which are generally due to mechanical wear.

Statistics from our five most recent major failures show that of the failed transformers, the youngest was 49 years old and the average age was 55. This supports our current base expected life for a power transformer of 60 years. Aside from the risks presented by condition issues and evident through historical performance, we face a number of other risks in relation to our power transformers, as outlined in Table 11-23.

Table 11-23: Key power transformer risks and mitigations

Risk/Issue	Mitigation
Oil spill	New transformers have bunding and oil containment Buchholz alarming to NOC or tripping advises control room of issues Some units have separate oil level indicators which may be alarmed Inspections check for oil levels, oil leaks, and rust that may cause leaks Corrective maintenance remediations
Early life failure due to preventable defects from the manufacturing process	Controls that ensure we get quality and consistency from our power transformer suppliers Design reviews for all new transformers and factory visits to inspect the transformer and witness factory acceptance tests are undertaken on every power transformer procurement Period supply agreements (PSA) with small numbers of manufacturers, combined with a standard procurement specification listing standard major components and transformer sizes
Fire as a result of transformer failure	Replacement transformers meet standard fire clearance requirements, otherwise a firewall is installed Oil containment and bunding reduces the consequences of an oil fire
Seismic event	New transformer arrangements are seismically compliant and protective devices do not have mercury switches Retrofit seismic hold-down programme where transformer is not being replaced in near term
Major active part failure or major OLTC failure	N−1 security (two transformers) for larger loads Mobile substation and contingency planning Replacement programme Oil testing Retention of unit spare parts once decommissioned, in case of future failures Strategic spare transformers Preventive and corrective maintenance of OLTCs
Lightning strike or switching surge	HV and LV surge arresters on new transformers as standard practice Retrofitting of surge arresters onto existing transformers where feasible
Excessive transformer noise	Investigating complaints and remediating to council limits if required Acoustic studies and transformer specification Fitting vibration pads under new transformers and considering retrofit on a case-by-case basis Consideration of moving to oil-directed air-natural (ODAN) transformers to avoid issues with noisy fans

Over the last 20 years, we have had six major power transformer failures at our substations that led to full replacement of the transformer:

- **Halfway Bush (age 59 at time of failure, failed in 2006):** the unit failed from the centre of the coil to the tank, most likely as a result of moisture ingress.
- **Roxburgh (age 49 at time of failure, failed in 2011):** it is suspected that arcing due to insulation failure led to a high amount of acetylene within the oil.
- **Halfway Bush (age 59 at time of failure, failed in 2013):** the unit failed due to water ingress.

- **Outram (age 61 at time of failure, failed in 2016):** the unit experienced a winding fault.
- **Clyde-Earnscleugh (age 58 at time of failure, failed in 2017):** the internal voltage transformer failed, leading to pollution inside the transformer rendering it unserviceable.
- **Remarkables (age 58 at time of renewal in 2024)**: OLTC had a mechanism failure due to age and excessive operations. Early signs of failure were detected through an enhanced condition assessment program before catastrophic failure. OLTC could only be used on fixed tap as a de-energised tap changer (DETC), so transformer was replaced as it was no longer suitable for use in its state and repairs were not cost-effective.

We assess the risk of our transformer fleet as described in Section 6.2. The AHI is determined as described in Asset health, above, and the key criticality dimension is reliability.

To determine criticality, we use a combination of both SAIDI and VoLL to measure the impact of an asset failure. In addition to these measurements, we utilise two different scenarios to understand the potential impact of an asset's failure:

- The worst-case scenario, where an outage cannot be minimised through external points of supply
- A distribution backfeed scenario, where the affected feeders are supplied via an alternative route through the distribution network

The reason for using these two scenarios is to include a weighting from the worst case, while at the same time ensuring the criticality is not overstated by considering the more likely case, where the outage is partially or fully covered through neighbouring substations. As we mature our approach, we intend to include security (N/N−1 configurations) considerations in our criticality iterations.

REPLACEMENT/RENEWAL

We do not run our power transformers to failure because of the potential network impacts, costly contingency response, long procurement times, and the potential safety risk of fire and explosion in the case of a catastrophic failure.

Power transformers have proven to be generally robust devices, but their internal condition cannot be directly observed and they can fail quickly without warning. This, combined with the potential wide range of material consequences and high replacement cost, fits well with the risk-based investment approach we have applied.

We forecast the risk profile of transformers and plan our interventions for when the risk of retaining a transformer in service is forecast to become intolerable according to our risk framework. We consider several options to address the risk prior to it becoming intolerable, including:

- **Replacement of the transformer.** This generally requires bringing all associated assets such as bunding, firewalls and protection up to modern standards.
- **Refurbishment (off-site) and component replacement (on-site).** These options are assessed but are generally only economic under limited circumstances and only for transformers aged at less than half their expected life.
- **Decommissioning of the transformer.** This option may be taken if the transformer is no longer required or if customers can be supplied from an alternative zone substation.

When assessing the need to replace a power transformer or otherwise mitigate transformer risk, we also consider alignment with other network requirements and end-of-life assets to ensure an efficient overall approach to managing these high value assets.

RENEWAL PRIORITIES

We renew power transformers based on risk, as informed by asset health and criticality. Our risk framework generates an 'AHI vs Criticality' risk matrix for all power transformers for the planning period. Those transformers for which 'AHI vs Criticality' shows the highest likelihood and highest consequence are considered to present an intolerable risk and need to be addressed or replaced. Refurbishment of assets is currently considered on a case-by-case basis but is generally limited to bushings, tap-changers, and oil replacement or filtration. We recently initiated an enhanced condition assessment programme for H1 and H2 power transformers, and one transformer has already been replaced as a result. Going forward, this work will provide greater certainty around our assessed health and subsequent assessment of remaining life on an asset-by-asset basis and ensure we are well positioned to optimise and appropriately prioritise our transformer renewal plans.

DISPOSAL

We dispose of power transformers when they cannot be redeployed and have no use as spare units or for spare parts. The principal components of oil, copper, and steel are recycled.

11.6.3. Switchgear fleet

Our switchgear fleet comprises indoor and outdoor switchgear that is located within zone substations. The primary function of switchgear is to connect, disconnect, and isolate network equipment such as 6.6 kV, 11 kV, and 33 kV feeder circuits, bus bar sections, and power transformers. Switchgear de-energises equipment to clear faults and provides isolation points to allow service providers to access equipment for maintenance or repairs.

Indoor switchgear as depicted in Figure 11-32 comprises individual switchgear panels assembled into a switchboard. These panels contain circuit breakers, current and voltage transformers, isolation switches, earth switches and busbars, along with associated metering equipment. They may also contain protection and control devices. Alternatively, these may be installed in a separate relay panel, sometimes located in a separate protection/control room.

Figure 11-32: Indoor switchboard at Andersons Bay

Our indoor switchgear fleet contains a total of 331 indoor circuit breakers (making up 28 switchboards).

Table 11-24 summarises the population by type, rated voltage, and sub-network.

Table 11-24: Indoor switchgear population by interrupting medium and operating voltage

Interrupting Medium	Voltage	Dunedin	Central Otago & Wānaka	Queenstown	Total
Oil	11 kV	125	7	0	132
	33 kV	0	0	0	0
	66 kV	0	0	0	0
SF_6	11 kV	13	0	7	20
	33 kV	3	0	6	9
	66 kV	0	0	0	0
Vacuum	11 kV	91	45	34	170
	33 kV	0	0	0	0
	66 kV	0	0	0	0
Total		**232**	**52**	**47**	**331**

The outdoor switchgear fleet comprises several asset types, including outdoor circuit breakers, air break switches, load break switches, earth switches, fuses, and reclosers. Circuit breakers and reclosers provide protection and control, while fuses provide protection and isolation only. Non-load break air break switches are used to isolate equipment but cannot be used to break load current. Load break switches connect, disconnect, and isolate equipment and can also be used to break limited load current.

Our outdoor switchgear fleet contains a total of 285 outdoor switchgear units, comprising circuit breakers, reclosers (within zone substations, reclosers provide zone substation circuit breaker functionality), and air break switches. Table 11-25 summarises their populations by type.

Table 11-25: Outdoor switchgear population by type/interrupting medium and operating voltage

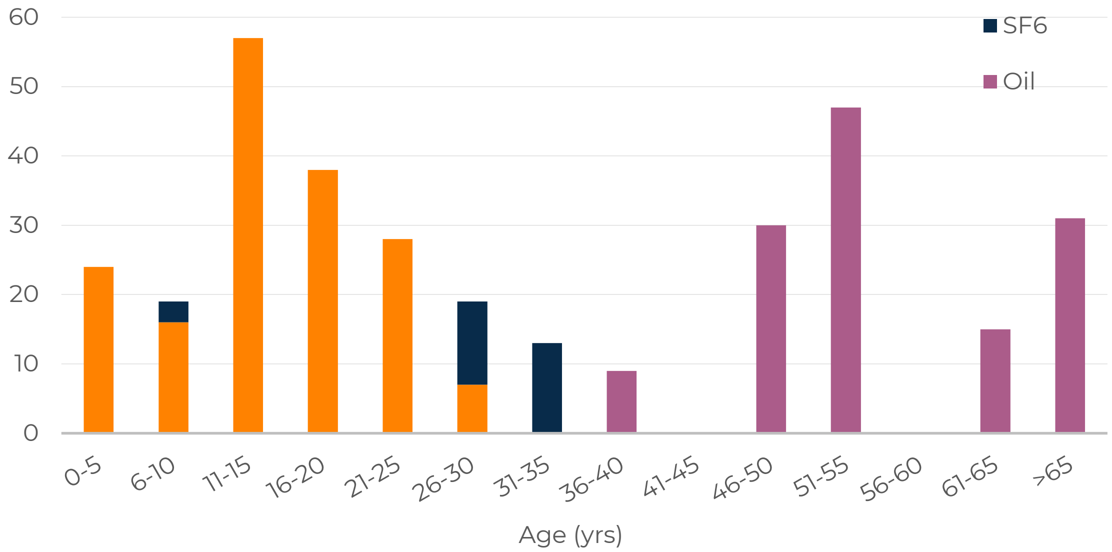
Interrupting Medium	Voltage	Dunedin	Central Otago & Wānaka	Queenstown	Total
Oil	11 kV	0	2	2	4
	33 kV	4	7	0	11
	66 kV	0	0	0	0
SF_6	11 kV	0	0	0	0
	33 kV	0	0	0	0
	66 kV	0	16	0	16
Vacuum/Reclosers	11 kV	0	7	9	16
	33 kV	15	15	12	42
	66 kV	0	0	0	0
Air break switches	6.6 kV, 11 kV, 33 kV, 66 kV	71	80	45	196
Total		**90**	**127**	**68**	**285**

ASSET AGE

The technology associated with switchgear has evolved over time. The majority installed prior to the 1990s used oil as the insulation and/or interrupting medium, and these make up a significant proportion of our present population. The remainder (generally installed after 1990) are vacuum or SF_6-insulated.

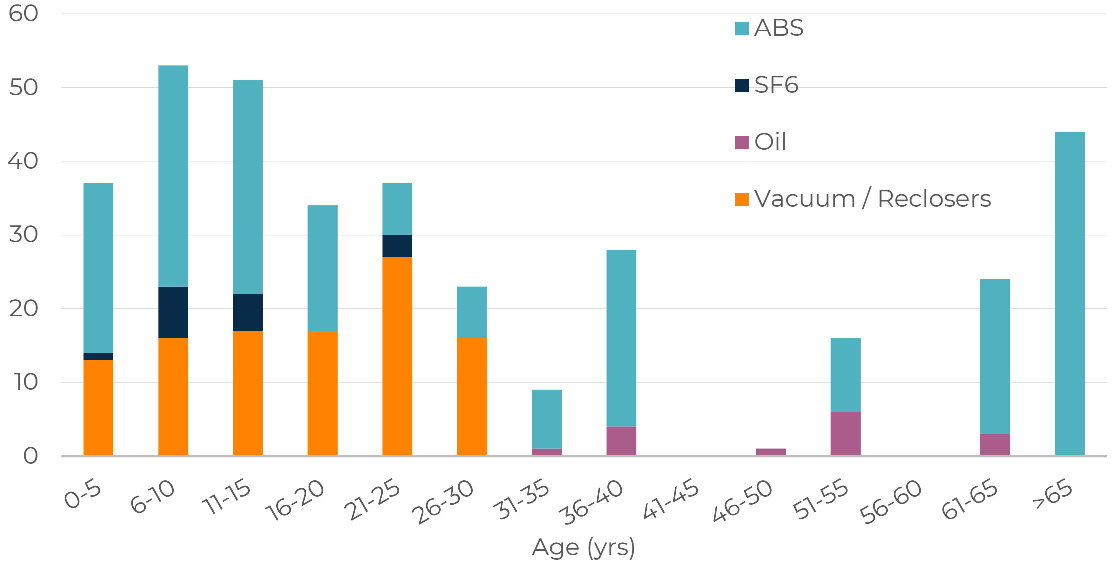
The average age of our indoor circuit breakers is 30 years, with those in our Dunedin sub-network region having a higher average age than those in our Central Otago & Wānaka and Queenstown sub-network regions. This is because the majority of our oil-insulated indoor switchgear is installed in Dunedin. Figure 11-33 shows the age profile of our indoor switchgear by circuit breaker type.

Figure 11-33: Indoor switchgear age profile



The average age of our outdoor circuit breakers is 20 years, with those in our Dunedin sub-network region having a higher average age than those in our Central Otago & Wānaka and Queenstown sub-network regions. Figure 11-34 shows our outdoor switchgear profile.

Figure 11-34: Outdoor switchgear age profile



ASSET HEALTH

We gather condition information on our switchgear during preventive maintenance and routine inspections. Insulation resistance, circuit breaker timing, contact resistance, high potential withstand, and other tests provide a good indication of circuit breaker condition. We also carry out thermal inspections to identify thermal anomalies and ultrasonic and transient earth voltage (TEV) measurements to monitor any partial discharge activity.

Routine testing and monitoring across the whole fleet allows us to track trends, enabling early identification of potential failure and continuous condition monitoring.

In applying our risk framework to this asset fleet, the key input is the remaining life based on age versus switchgear life expectancy. The life expectancies shown in Table 11-26 are based on standard industry practice.

Table 11-26: Switchgear expected life by insulating medium

Circuit Breaking Medium	Indoor switchgear		Outdoor switchgear	
	Average age	Expected life	Average age	Expected life
Vacuum	14	45	17	45
SF_6	28	45	10	45
Oil (bulk and minimum)	56	60	35	50

While equipment age provides a reasonable proxy for switchgear health, we aim to further develop our asset health framework to include measured condition parameters from electrical tests as well as non-condition EOL factors such as obsolescence and maintainability (access to personnel with the necessary skills to carry out maintenance work, availability of spares, etc.).

A significant proportion of the indoor switchgear fleet (14%) has an asset health score of H1 and needs replacement in the short term. Further, 33% of indoor switchgear assets have an asset health score of H3 or less, meaning they will require replacement early in the planning period. This is largely driven by our ageing oil-filled circuit breakers.

Specific asset health issues identified across the fleets are as follows:

- Two 11 kV switchboards of the same type at different zone substations have lower insulation resistance than expected, indicating that they are reaching end-of-life. Overall, the condition of our indoor switchgear is commensurate with its age profile and supports replacement at selected sites.
- Until 2020, we were not able to internally access our minimum oil circuit breakers due to unavailability of spares from the manufacturer. We then embarked on dismantling a spare unit to create bespoke parts and are now in a programme of undertaking full condition assessments of

our 11 kV circuit breakers. For 33 kV minimum oil circuit breakers, we have not been able to assess contact condition but are able to flush the oil during maintenance. We recognise the need to replace these circuit breakers, and work to replace them is at various stages.

- We identified a potential failure mode caused by moisture ingress via the breathers and seals on the bushings and air breathers on a type of oil-immersed interrupter vacuum circuit breaker (VWVE). We modified the air breathers and improved the bushing seals; and so far, this work appears to have addressed the issues.
- We have a population of indoor-type minimum oil circuit breakers (ABB type HKK) that have been installed in poorly-designed locally-fabricated outdoor cubicles in our switchyards. One installation of these circuit breakers has been set up as a switchboard where the circuit breakers can be withdrawn as per a normal indoor switchboard of this type. The others have the interrupter and mechanism installed in a small enclosure on top of a transformer and are fixed rather than withdrawable. In the 1980s this type of 'homemade' installation was considered cost-effective, but we (and other EDBs) have experienced issues with these installations. We believe this has been primarily due to water ingress and internal pollution leading to flashovers. Further, the cubicles are lined with Pinex, a wood product, so they contain further fuel in the event of a catastrophic failure, in addition to the oil in the circuit breakers.

Figure 11-35 summarises the current health profile for our outdoor circuit breakers. It illustrates that approximately 10% of the fleet has already exceeded its life expectancy (H1) and also shows the health profile forecast for the planning period in the case of no expenditure.

Figure 11-35: Projected outdoor switchgear asset health

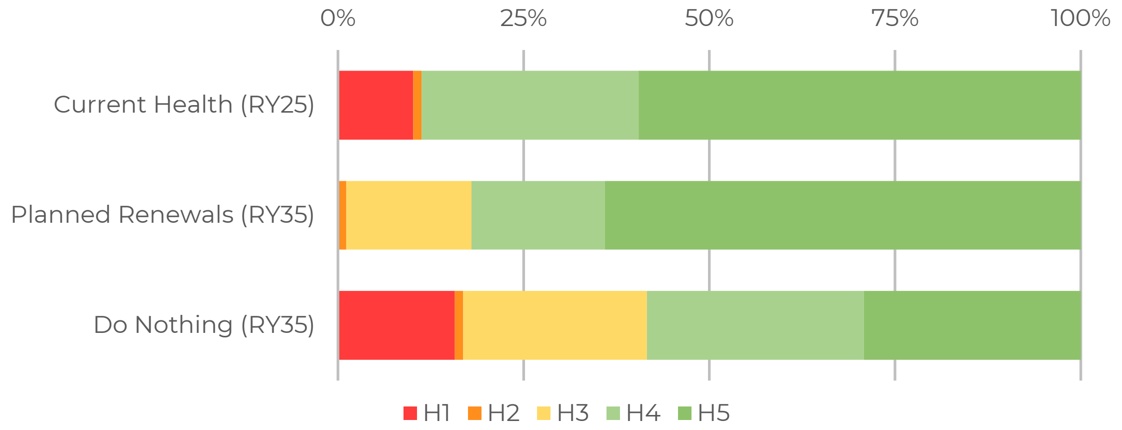
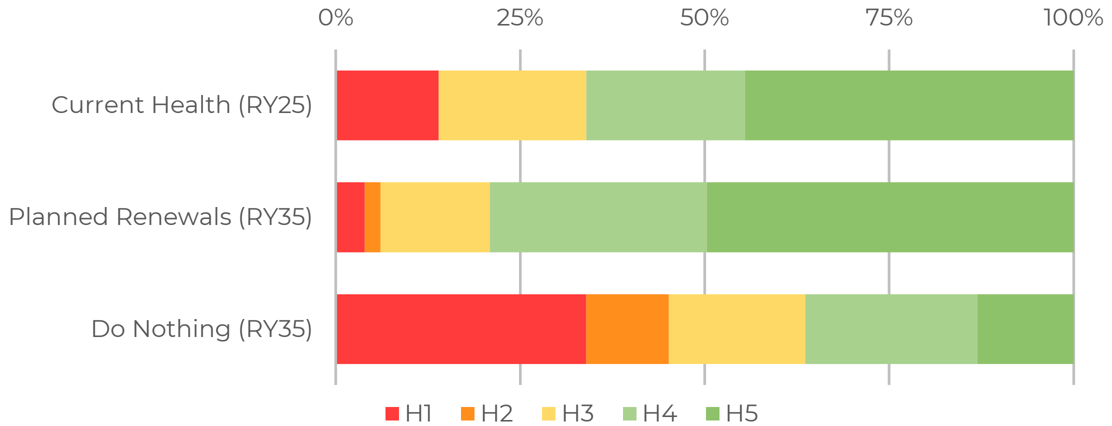


Figure 11-36 summarises the current health profile for our indoor switchgear. The planned level of expenditure will enable us to manage a critical safety and reliability risk, and the planned renewals programme will improve overall fleet health.

Figure 11-36: Projected indoor switchgear asset health



ASSET PERFORMANCE AND RISK

Our switchgear fleet is generally performing well; however, the level of risk posed by these assets is increasing as they age and their condition deteriorates.

The main risk is related to safety of personnel due to a potential failure mode where an arc flash (a fault between phases or earth) occurs, which can release a large amount of energy and cause an explosion. In addition to being housed in confined spaces, a large proportion of the indoor switchgear fleet is not rated to contain an arc fault and is oil-insulated, which fuels the explosion and subsequent fire. Secondary impacts of this failure mode are damage to nearby assets and a significant impact on reliability and network security, as the switchboard will likely be rendered unserviceable and require complete replacement.

We have a Purchase Service Agreement with a single manufacturer for 11 kV indoor switchgear, which will drive efficiencies through design, procurement and construction as we ramp up our replacement programme. This switchgear is fully arc fault contained and externally vented, uses vacuum interrupters, and does not contain SF_6. This reduces the type of risk we face on older equipment to very low levels.

Outdoor switchgear has a lower risk profile compared to indoor switchgear as it typically comprises individual circuit breakers physically separated by a distance rather than installed in a single switchboard. This reduces the reliability impact of an individual failure, while not being in a confined space reduces the impact of an explosion. However, our ageing population of outdoor switchgear has a track record of poor performance and we have experienced the following switchgear failures:

- In 2012, an indoor SF_6 11 kV circuit breaker (ABB type HPA) in an outdoor cubicle/switchboard arrangement failed at a Central Otago zone substation. While the root cause is unknown, this resulted in a switchyard fire.
- During the clearance of an 11 kV feeder fault at a Central Otago zone substation in late 2019, oil was expelled from the breather of one of the minimum oil 11 kV circuit breakers (ABB type HKK) that are installed in outdoor cubicles.
- We have experienced a number of Canterbury Engineering 33 kV air break switch (ABS) failures due to the breakdown of the cement compound that bonds the two-piece insulators to the steel frame of the ABS. We have a replacement programme in place and work to replace the insulators is at various stages.

Table 11-27 summarises the key risks identified in the fleet and their associated mitigations.

Table 11-27: Key indoor switchgear risks and mitigations

Risk/Issue	Mitigation
Arc flash	Regular maintenance and remote switching of circuit breakers Operational management, PPE, signage in substations, barrier off rear and sides of switchgear Arc flash protection installed or retrofitted to switchboards with material remaining life Neutral earthing resistors (NER) installed or retrofitted to reduce earth fault levels, which are particularly high in the Dunedin 6.6 kV network
Compound filled cable box	PPE, signage in substations, barrier off rear and sides of switchgear
Major oil circuit breaker failure leading to arc flash, fire, and major service disruption	Operational management, PPE, signage in substations Switchboard replacement programme Dunedin sub-network architecture changes Mobile substation and other contingency planning
Seismic event	Structural modifications where required Replacement plan
Failure to operate during fault conditions	Coordination of protection systems to ensure the provision of backup fault clearing Regular maintenance
SF_6 leaks	Monthly checks of gauges and remediation if required Avoidance of SF_6 in new equipment where possible

Risk/Issue	Mitigation
Lightning strike leads to switchgear failure or damage	Surge arresters on overhead to cable interfaces Surge arrester retrofits, particularly where circuit breakers sit open for long periods Insulation coordination reviews Overhead earth wires
ABS insulator failure	Check cement and replace 33 kV ABS two-piece insulators as required

REPLACEMENT/RENEWAL

We forecast the replacement of indoor switchgear on the basis of risk, as informed by asset health. We do not run our indoor switchboards to failure because of the potential consequences of a major failure including arc flash, fire and explosion leading to severe harm or death, potential network impacts, costly contingency response, and long procurement times. Asset health is currently assessed as remaining life based on age versus life expectancy.

We use an age-based model to forecast renewal requirements and are working on incorporating a reliability criticality assessment into our forecasting framework. Where a significant amount of outdoor switchgear is planned for renewal, we consider conversion to modern indoor equivalents upon assessing the costs and benefits. Indoor options are preferable where safety clearances in the outdoor switchyard do not meet current standards. Indoor options also provide improvements, such as the addition of a bus section circuit breaker and busbar protection, reduced vulnerability to weather events, and no exposed high voltage outdoor buswork.

We also overlay the replacement requirements of switchgear with known condition or type issues, as well as any considerations regarding availability of spare parts or other maintainability concerns, to determine overall network replacement needs. We intend to further improve our AHI models to include condition-based EOL drivers.

In some instances, we may replace switchgear earlier than forecast where condition has been assessed as having deteriorated more quickly than anticipated or where efficiencies can be achieved by combining replacement with other zone substation work. Typically, switchgear renewals are grouped with other zone substation renewals and delivered as a single project.

RENEWAL PRIORITIES

The approach to renewal as detailed above for switchgear provides a prioritised renewals programme that starts with risk-based assessment and steps through systemic and type issues to non-condition-based drivers (spare parts, obsolescence, workforce skills), to ensure an effective and optimised approach.

We have identified the following replacement priorities.

END-OF-LIFE REPLACEMENT OF INDOOR OIL-FILLED SWITCHGEAR

In consideration of this risk, our approach to indoor switchgear renewal includes a programme of oil-filled switchgear replacement.

Having completed the replacement of oil-filled switchgear at Andersons Bay zone substation in 2023, we are now in the process of replacing the following:

- Green Island zone substation indoor switchboard
- Smith Street zone substation indoor switchboard

During this 10-year planning period, we plan to prioritise the renewal of the following oil-filled indoor switchgear:

- Halfway Bush zone substation indoor switchboard
- Willowbank zone substation indoor switchboard

EAST TAIERI ZONE SUBSTATION REPLACEMENT OF INDOOR SWITCHGEAR INSTALLED IN OUTDOOR CUBICLES

An indoor SF_6 11 kV circuit breaker (ABB type HPA) in an outdoor cubicle/switchboard arrangement failed at a Central Otago zone substation. Oil was expelled from the breather of one of the minimum oil 11 kV circuit breakers (ABB type HKK) installed in an outdoor cubicle.

DISPOSAL

We dispose of all switchgear when it has reached EOL and is removed from service. Where a switchboard of the same make or model remains in service at another site, we will assess the removed unit for retention of spare parts and keep it as required.

SF_6 is a greenhouse gas and can be contaminated with toxic arc byproducts. It is handled by specialist contractors and disposed of appropriately. Other switchgear components, including oil, copper, aluminium and steel, are recycled.

11.6.4. Ancillary zone substation equipment

Our ancillary zone substation equipment fleet comprises equipment in our zone substations that does not fit into one of the above categories. It includes load management equipment, outdoor structures, instrument transformers, neutral earthing resistors, surge arrestors, buswork, generators, and local service supplies.

RIPPLE INJECTION

We presently use ripple injection equipment to control street lighting and to manage load during peak demand periods, which supports deferral of network expenditure. We currently have both 317 Hz and 1050 Hz ripple injection systems running in parallel, but we are at an advanced stage of decommissioning our legacy 1050 Hz ripple injection systems.

In Dunedin, we operate two or three ripple injection load control systems in parallel, using modern solid-state 317 Hz systems to inject at GXPs. These units are controlled via the Dunedin SCADA master station. We have two injection units at one GXP and one injection unit with two converters at the other.

In the Central Otago & Wānaka region we have two injection units in zone substations, and in Queenstown we have an injection unit at a GXP.

GENERATORS

We use generators to manage load during peak demand periods. We have two 2 MVA generators, one installed at the Omakau zone substation and the other installed at the Camphill zone substation.

OUTDOOR STRUCTURES

Outdoor structures support buswork, which distributes power to different connected circuits at a zone substation. Structures vary in type and arrangement and can consist of concrete or wooden poles, steel lattice structures, or other steel structures. Many designs are legacy and have varying degrees of non-conformance with modern standards. Structures with material non-conformances that breach current industry practice (and associated primary plant) are replaced at end-of-life. For all replacements we consider the option of replacement with an equivalent indoor switchboard solution for improved safety, network performance, and visual amenity.

ASSET AGE

Local service equipment, surge arrestors, instrument transformers, buswork, and outdoor structures tend to be the same age as the original substation and are replaced if at EOL as part of larger zone substation projects, although some have been replaced earlier due to assessed poor condition. At present, our data is not sufficiently detailed to provide age profiles for these assets.

Our aged K22/Decabit 1050 Hz ripple injection system consisted of 16 injection plants injecting into distribution circuits at each Dunedin zone substation. We had 15 rotary plants installed between the 1950s and the 1970s and one static plant installed in the 1990s. These have been progressively decommissioned, and to date only two remain. Both of these are forecast to be decommissioned by the end of first quarter in 2025. We have another three Decabit 317 Hz solid state ripple injection plants in Central Otago. Two of these were installed in 2009 and 2010, while one consists of a 1984-vintage coupling cell with a 2015-vintage converter.

The condition and health of our ancillary equipment is assessed during routine inspections and preventive maintenance. As this fleet contains a variety of equipment, we do not have a single framework for assessing asset health. Our general approach is to carry out relevant tests and visual inspections during preventive maintenance to check condition and determine asset health.

We do not have any significant issues with the condition of our outdoor structures. Some mass-reinforced concrete pole support structures in zone substations have minor spalling, which is treated with a rustkill/sealant product. Given their low loadings compared to concrete poles with long overhead conductor spans, this condition is deemed acceptable at present.

Our 317 Hz ripple plant converters have a design life expectancy of 15 years; and with the majority now 13 years old, these units are approaching EOL. The coupling cells are also the same age as the converters but have longer life expectancies, except for the Alexandra coupling cells installed in the 1980s.

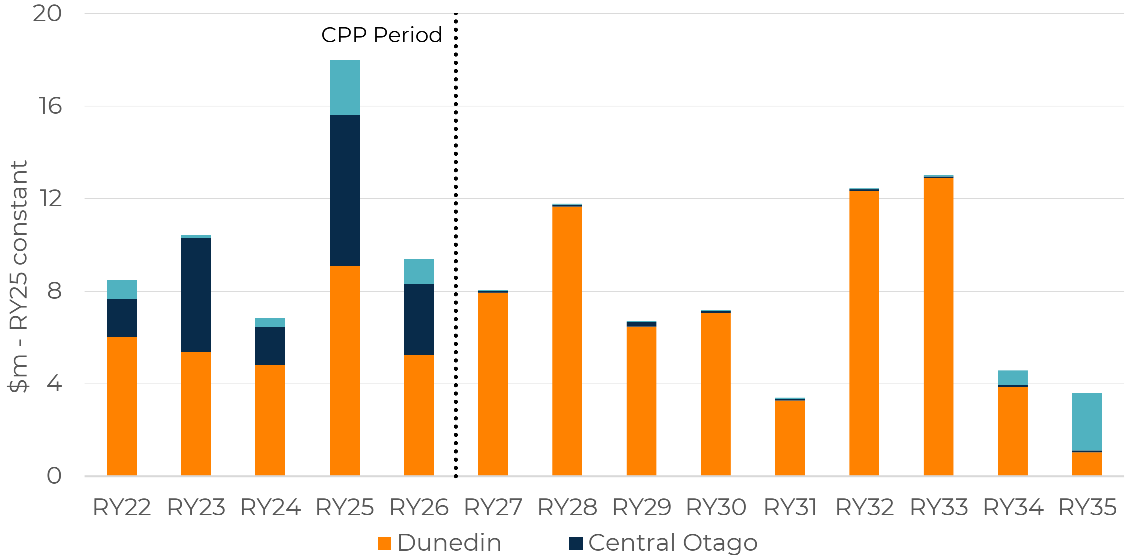
OVERALL ZONE SUBSTATION FORECAST EXPENDITURE

There is a notable change in the forecast for zone substation renewals from previous forecasts, in the form of an increase of $19m over the next 10-year reporting period.

The following factors contributed to our forecast for AMP25:

- Shift in the driver for the Mosgiel zone substation rebuild, from primary driver *Growth* to primary driver *Renewal*
- Enhanced cost estimation processes, with enhanced focus on optimising scope for the budget year
- Deferral of a number of renewal projects, making way for growth-driven projects including consideration of project (renewal and growth) sequencing to enable access to the network
- Rollover of expenditure for ongoing projects into other regulatory years
- Re-prioritisation of projects following enhanced condition assessment
- Consideration of overall network resilience following the completion of growth projects, where more options for back-feeding are achievable

Figure 11-37: Total capex forecast zone substation expenditure by region (RY25 constant, $m)



Note: The above expenditure profile also includes secondary system renewals that are driven by zone substation renewals. Standalone secondary system renewals are captured in Section 11.9.

11.7. DISTRIBUTION SWITCHGEAR

Distribution switchgear is the collective term for equipment used to provide network isolation, protection, and switching facilities outside of zone substations. This portfolio comprises the following asset fleets, which are described in the sections that follow:

- HV ground-mounted switchgear
- Pole-mounted switchgear (which includes air break switches (ABS), pole-mounted reclosers and sectionalisers, and pole-mounted fuses and links)
- LV enclosures, which includes underground link boxes and above-ground pillars
- Ancillary distribution equipment

11.7.1. Ground-mounted distribution switchgear fleet

Our ground-mounted distribution switchgear operates at 11 kV and 6.6 kV. We have approximately 1,600 units across our sub-networks with a variety of insulating media consisting of air, oil, and SF_6. Table 11-28 depicts the fleet split by sub-network and make/model.

Table 11-28: Ground-mounted distribution switchgear population by sub-network

Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Statter oil-filled	76	0	0	76
Long & Crawford oil-filled	192	0	0	192
ABB SD Series oil-filled	218	168	238	62
ABB SafeLink2 SF_6-insulated	162	216	142	520
ME/ETEL air-insulated	3	105	58	166
Siemens 8DJH SF_6-insulated	0	2	1	3
ENTEC HALO solid dielectric	18	10	4	32
J&P oil-filled	2	0	0	2
Reyrolle oil-filled	1	0	0	1
Tamco vacuum-insulated	3	0	0	3
Total	**675**	**501**	**444**	**1620**

ASSET AGE

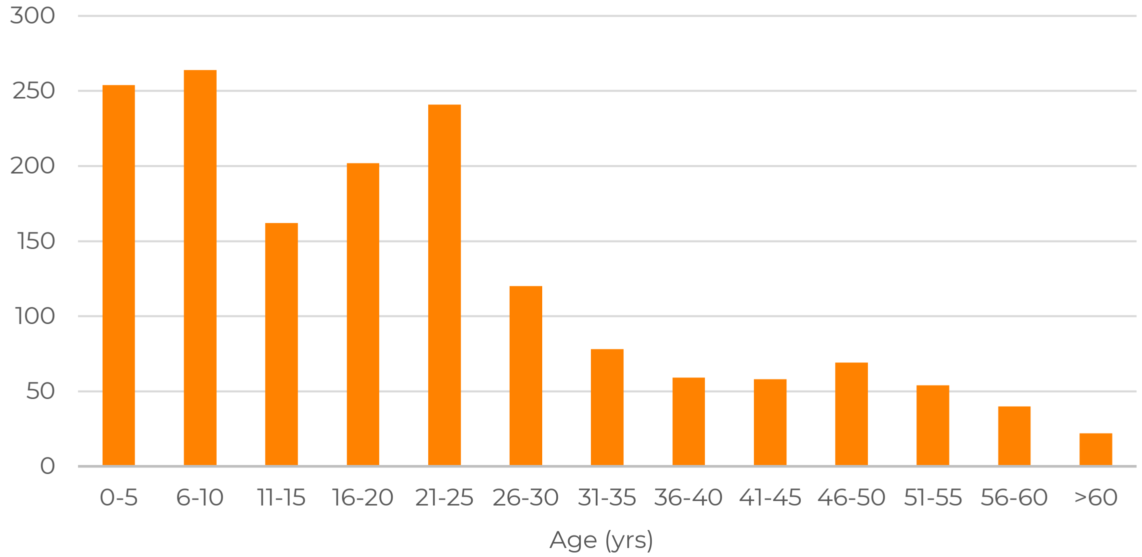
Our Fleet Strategy documents define type-specific expected useful lives ranging from 40 to 70 years, informed by condition. Figure 11-38 depicts the fleet's age profile.

The fleet includes 221 oil-filled switchgear units that are already beyond the EEA AHI Guide maximum practical life (MPL) of 40 years, with 22 of those units already beyond 60 years.

Another 126 oil-filled switchgear units will exceed the EEA AHI Guide MPL over the planning period.

Of the 816 ABB SD Series 2 and L&C oil-filled switch gear units, 741 have had invasive maintenance overhauls completed in recent years. The remaining 75 units will have undergone invasive maintenance overhauls if not replacement during the planning period.

Figure 11-38: Ground-mounted distribution switchgear fleet age profile



ASSET HEALTH

The AHI of our ground-mounted distribution switchgear is calculated based on our AHI methodology described in Section 6.4 and is informed by expected life, maintainability, condition, age, and type.

The AHI model for this fleet is largely weighted by age, with some minor adjustments based on condition data and time since last maintenance, to establish what is referred to in the model as the 'informed effective life'.

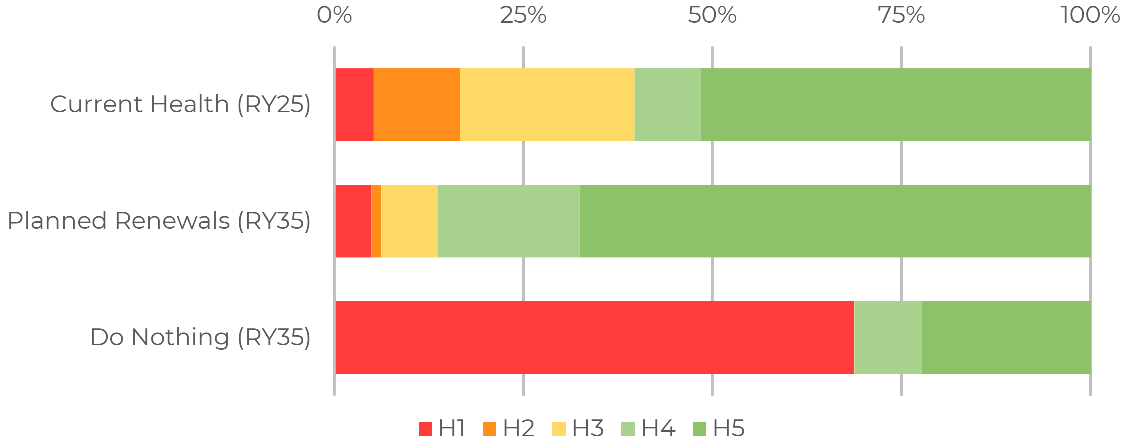
However, because the forecast health of assets is currently only age-based, the model gives a highly conservative view of future health. **Figure 11-39** depicts the current fleet health alongside the forecast health and the counterfactual 'do nothing' scenario.

As our knowledge of asset condition improves, we will continue to mature our AHI model to incorporate specific condition issues, location of assets, and risk mitigation measures to improve the health forecast of our assets.

We envisage that it will be necessary to update the AHI model to take into account cases where an asset has type issues or is obsolete and mitigating measures have been determined and implemented. It will also be necessary to incorporate trending of past condition data to predict future health.

We further intend to assess the possibility of increasing some maintenance activities as a means for managing risk and investment priorities.

Figure 11-39: Projected ground-mounted distribution switchgear health index



ASSET PERFORMANCE AND RISK

Our historical outage records indicate relatively few outages caused by faulty ground-mounted switches. However, we do presently have a number of switches that are in poor condition or which have known type issues that we are in the process of addressing. When ground-mounted switches fail, we undertake RCA to understand the causes and inform emerging failure modes, effects, and mitigation actions.

We note that because these assets are installed on the ground in urban areas, they have an elevated risk profile (criticality with respect to public safety) in comparison with other switchgear assets.

Specific asset performance and condition issues on the network include the following.

- Operational risks exist for specific models of Reyrolle oil-filled switches and Entec. We are managing these through planned replacement programs, with operational restrictions applied until they are replaced.
- Because these assets have a long serviceable life, there is potential for obsolescence-related issues to arise from the perspective of maintenance, due to difficulty in sourcing spare parts and technical knowledge. Where relevant, these issues may necessitate asset replacement.

Given that we use age as a proxy for condition and obsolescence, we note that Aurora Energy has 240 oil-filled switchgear units that are already beyond the expected serviceable life of 40 years, with 39 of those units already more than 60 years old. This demonstrates an elevated risk from this asset fleet.

Potential future risks that have been identified include the following.

- The current standard switch is SF_6-filled. As a greenhouse gas, this may trigger future environmental and reporting challenges for Aurora Energy.
- Distribution ground-mount switchgear is becoming more complex in relation to automation and circuit breaker functionality. Increased complexity may result in a shorter life expectancy due to the electronic components where these are not separately replaceable.

Table 11-29 summarises the key risks in our ground-mounted distribution switchgear fleet and their associated mitigations.

Table 11-29: Key ground-mounted distribution switchgear risks and mitigations

Risk/Issue	Mitigation
Reyrolle's oil-filled units suffer safety and performance risks due to design and installation/tilt issues	Operating procedures Programmed replacement
Arc flash event with potential to harm operator or public (with all non-arc fault contained switchgear)	Remote operation via actuator or lanyard for older switchgear where at all possible Any maintenance on an RMU is only undertaken when it is fully de-energised with remote isolation in place Replacement switchgear is arc fault contained
Ground-mounted distribution switchgear units past tilt limit cannot be operated	Measurement before operation to control safety risk Corrective maintenance programme
Third-party damage or access	Installation of visible warning signs Inspections and replacement of locks Design choice of location 'Package covers'; repair and replacement
Live operation of JW fuses has an arc flash risk	Safety risks controlled by DNO order (although this creates a reliability issue) Future: prioritised LV switchboard replacement plan
SF_6 release to atmosphere	Periodic checking of pressure gauges Specialist SF_6 handling

REPLACEMENT/RENEWAL

The forecast for replacement of ground-mounted switches is informed by the fleet strategy, which applies a risk-prioritised approach that takes into account our ability to deliver, as well as the type, age and condition, failure modes, and maintainability of each asset.

We adjust the year-to-year programme defined in the fleet strategy based on inspection and maintenance insights to inform the renewal strategy. We also consider the location of the assets, prioritising those in safety critical zones. Assets identified as being above the tolerance boundary but without any other known issues are verified through inspection to confirm the risk assessment and then scheduled for replacement.

To ensure efficiency and minimal cost to consumers, we also consider a range of options prior to replacement, including whether we can repair assets rather than replacing them, whether changes to the network topology would enable the asset to be decommissioned, and whether there are viable non-network options.

RENEWAL PRIORITIES

The renewal approach as detailed above for ground-mounted switchgear provides a prioritised renewals strategy that starts with a risk-based approach and then considers specific condition issues and non-condition-based drivers (spare parts, obsolescence, workforce skills). As a result, we have the following replacement priorities.

REPLACE OBSOLETE OIL-FILLED SWITCHES

Our renewal strategy is to remove all oil-filled ground-mounted switchgear from our network. The programme prioritises the asset makes and models that have known issues, and then addresses the remainder based on age. This programme will be reviewed as the assets age and if any new defects or failure modes arise and our knowledge of the asset condition improves.

The assets will be replaced in order of highest to lowest risk, with our current risk assessment indicating the following sequence:

- Replacement of all Eaton, J&P, Reyrolle, Statter, Tamco, and Entec Halo units
- Incorporation of ME/ETEL boxes in the programme
- Replacement of Dunedin oil-filled L&C units
- Replacement of Dunedin oil-filled ABB SD Series 2 units
- Replacement of Central Otago oil-filled ABB SD Series 2 units

SPARE PARTS AND TRAINING

To improve our response to outages and be able to undertake effective maintenance, we plan to improve our spare parts management. Specifically, the longer-term replacement timeframe for the L&C and ABB SD Series 2 units means we must have sufficient spares and critical spares in our stores, along with a workforce trained to an appropriate skill level. This will ensure these assets remain safe and reliable while they are on our network.

DISPOSAL

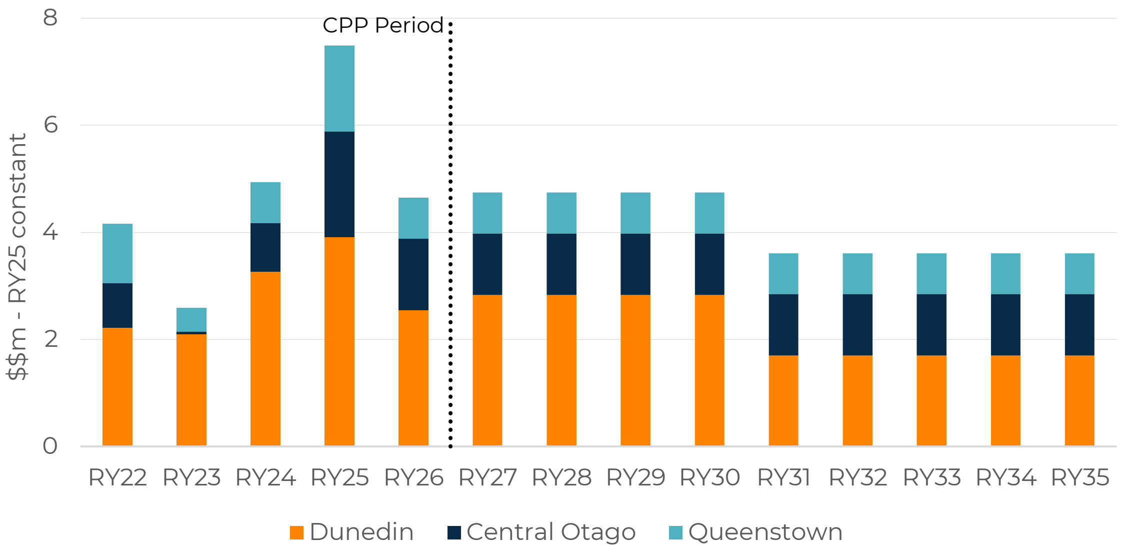
Removed ground-mounted distribution switchgear that will not be reused on the network may be retained as donor units for parts, where compatible makes and models are still in use. We also offer units to other EDBs where appropriate.

For final disposal of units:

- Oil is recycled and reused
- SF_6 is collected by third-party contractors approved to recover SF_6
- Steel is collected by third-party scrap dealers

FORECAST EXPENDITURE

Figure 11-40: Capex forecast ground-mounted distribution switchgear by region (RY25 constant, $m)



11.7.2. Pole-mounted distribution switchgear fleet

This section describes our pole-mounted switchgear, which primarily comprises ABSs, reclosers, and sectionalisers. Note that because we treat fuses as consumable items, they are not covered in this analysis. Similarly, links are currently treated as maintenance-free devices and are not considered here.

ABSs use air as the dielectric and can be operated via a handle mounted on a pole. They are used for sectionalising feeders to isolate faults and facilitate maintenance, and as open points between feeders. They are used from 6.6 kV up to 66 kV and can be load break or non-load break. Non-load break ABSs are restricted in terms of how they can be used operationally.

Reclosers and sectionalisers operate at 11 kV and 6.6 kV, with the insulating medium consisting of oil or vacuum. These units are used to improve the reliability of our network by limiting the area impacted by faults. Reclosers have protection capabilities and reclose settings that can be configured for each device individually. They can automatically open when a fault is detected and then attempt to reclose in the case that the fault was transient. This helps improve the performance of our network. In some of our smaller zone substations, we use reclosers as circuit-breakers, with a total of 51 of our units functioning in this capacity.

Sectionalisers are gas-insulated switches that can be operated at the switch or remotely to de-energise parts of the network. Sectionalisers do not have any protection or automated functionality.

Table 11-30 provides an overview of the population of pole-mounted switches on our network. Note that this table does not include the reclosers that function as circuit-breakers.

Table 11-30: Pole-mounted distribution switchgear and recloser populations by sub-network

Asset Type	Population			
	Dunedin	Central Otago & Wānaka	Queenstown	Total
ABS	515	397	147	1059
Reclosers	15	28	15	58
Total	**530**	**428**	**165**	**1123**

ASSET AGE

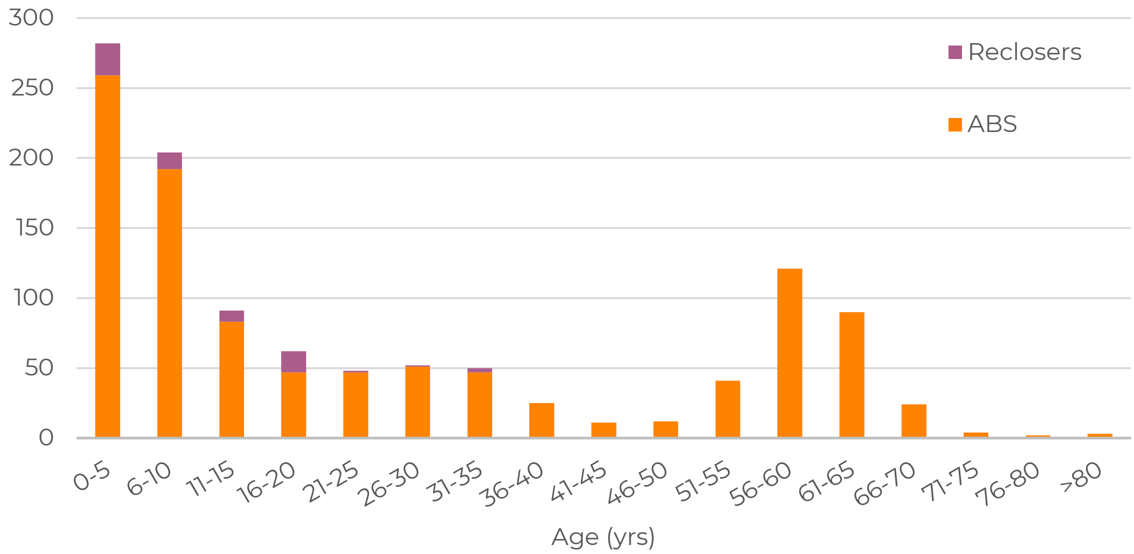
Our fleet strategy documents define the life expectancies of our pole-mounted switchgear.

- The life expectancies of our ABSs vary by type, ranging from 30 to 65 years.
- The life expectancies of our reclosers vary by type, ranging from 30 to 40 years.
- Our switches have an average age of 28 years against a maximum practical life (MPL) ranging from 45 to 65 years.

At this stage we have a low level of confidence in the age data for this fleet. But through the rollout of our updated overhead inspection programme inspection – including thermal inspections on these assets – we will be able to better inform the AHI model, including a shift to condition-based criteria and verification of expected life, and thereby focus our spending where we know it is needed.

Figure 11-41 depicts the fleet's age profile.

Figure 11-41: Pole-mounted distribution switchgear age profile



ASSET HEALTH

Historically, there have been low levels of maintenance on our pole-mounted switches and many of our switches are only operated after a fault occurs or when an outage necessitates sectionalising the network. As a result, we have a relatively low level of confidence in our asset data and subsequently the asset condition.

Our reclosers have a four-year maintenance cycle so are generally in good condition, with the exception of coastal located units, which are prone to corrosion due to the airborne salt in the atmosphere. Additionally, our control units for the reclosers are reaching an age where ongoing aftersales support for parts is declining as new technology renders them obsolete.

We have undertaken a desktop review, which has improved our understanding of type and age information, and we are increasing inspections and maintenance to address issues and gather information to verify our analysis. Our revised inspection programme will also include new techniques such as comparative thermography on ABS contacts and connections to further advance our understanding of this asset class.

Common issues that we have identified through our analysis to date, coupled with the experience of personnel, are:

- Due to infrequent use, mechanisms seize, necessitating maintenance or renewal (particularly common in coastal areas)
- We are experiencing corrosion issues with some of our older pole-mounted switches, particularly in coastal areas
- We have identified multiple types of ABSs and links that suffer insulator failures

The combination of condition issues means we sometimes judge that the switches cannot be operated safely. In these cases, they are tagged *Do Not Operate* (DNO), which impacts the ability to switch our network in response to faults or for planned outages.

AHI for both pole-mounted switches and reclosers is based on expected remaining life. Figure 11-42 and Figure 11-43 below compare projected AHI in RY35 following planned renewals with a counterfactual 'do nothing' scenario for pole-mounted switches and reclosers, respectively. For pole-mounted switches, this indicates that while planned expenditure does not set us up to be in a better position at the end of the period, there are clear benefits to current spending levels. This model is informed by limited data and is age-based; however, our new overhead inspection programme is starting to provide better quality information that will help us prioritise expenditure and refine our forecasts going forward. As we get on top of other fleets where safety drivers are more critical and we enhance the data set for this fleet, we will address the apparent emerging backlog.

Figure 11-42: Projected pole-mounted switch asset health

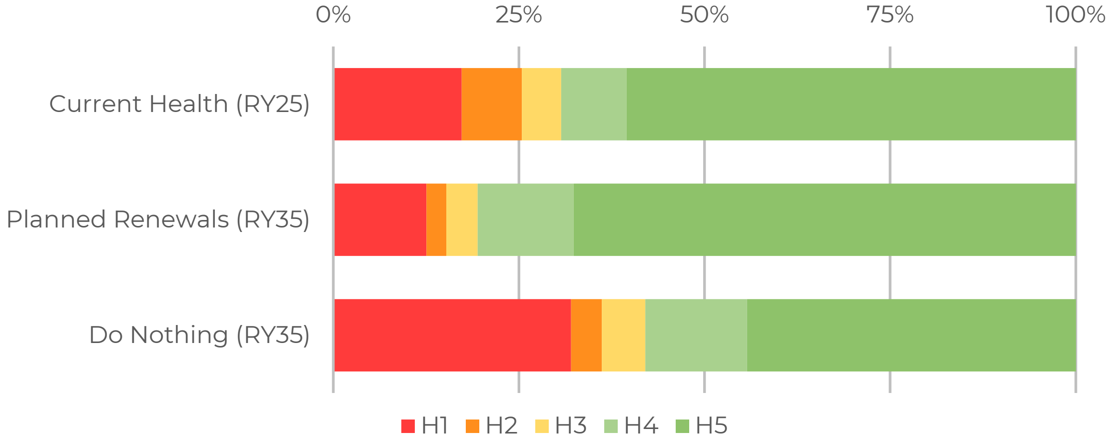
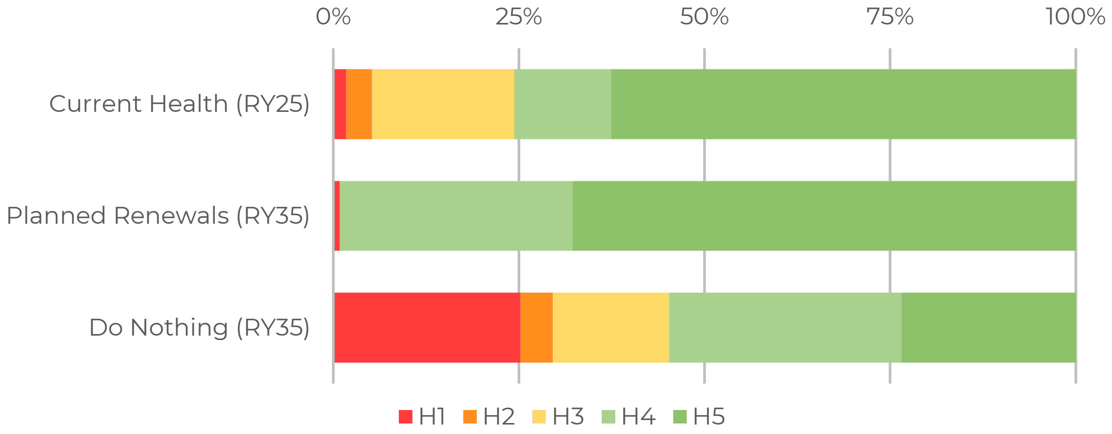


Figure 11-43: Projected recloser asset health



ASSET PERFORMANCE AND RISK

Our historical outage records indicate relatively few outages caused by faulty pole-mounted switches. However, we do presently have a number of poor condition switches that are inoperable, and the state of some of our older pole-mounted switches has led to some performance issues. This can limit our ability to reduce the impact of outages, and in some cases, they can prevent service providers from carrying out planned works.

The majority of our reclosers are in good condition. Our outage records indicate that on average we experience one faulty recloser every two years. This outage rate includes when a recloser has failed to operate following a line fault. We have had one instance where a bird strike led to a phase-to-phase fault and destructive failure of the recloser. To mitigate this risk, we are retrofitting wildlife guards to the Nova 15 units, on which the clearances between phase bushings are particularly tight. We have had isolated problems with some controllers from our recloser fleet, and Cooper Power Systems KYLE F6-P2B control units are no longer supported by the manufacturer.

Table 11-31 sets out the key risks identified for our pole-mounted switchgear and their associated mitigations.

Table 11-31: Key pole-mounted distribution switchgear risks and mitigations

Risk/Issue	Mitigation
Recloser cannot be easily removed from service for maintenance	Installation of bypass facilities
Auto-reclosing leads to fire	Operational procedures (blocking auto-reclose in high fire risk seasons/sub-networks)
Controller failure means recloser does not operate; Cooper Power Systems KYLE F6-P2B control units are no longer supported by the manufacturer	Inspection and maintenance Replacement programme
Bird strike at recloser terminals, causing phase-to-phase fault	Presently considering risk mitigations – for example, insulating droppers Standard equipment choice to have adequate pole spacing
Lack of easement on sites installed post-1992	Obtain easement New site chosen when renewing or adding; bypassing if easement cannot be obtained for existing site
Cement failure between shields (Canterbury Engineering type two-piece 33 kV insulator ABS)	Replacement of the ABS insulator with 4944 or replacement ABS
Insulator failure at top casting (Mahanga Holdings ETE ABS)	Reactive replacement of ABS
Insulator failure due to sulphur cement failure on top casting (1985-era 11 kV insulator ABS)	Largely resolved through historical replacements
A type of legacy HV link is prone to breaking on opening	Operating restrictions Type-based replacements
Inoperable/DNO ABSs	Maintenance and replacement programmes

REPLACEMENT/RENEWAL

We forecast the required budget and expected volumes for replacement of pole-mounted switches based on our AHI and risk assessment methodology, which incorporates inputs based on the outcomes of asset inspections. The actual programme of works is based on the outcomes of asset inspections and prioritises assets with specific known issues or type issues based on risk, and is aligned to works on associated assets (such as the pole the switch is attached to).

To ensure efficiency and minimal cost to consumers, we also consider whether the switch can be repaired rather than replaced, based on the make and model of the unit and the type of defect found. Typically, replacement with the modern equivalent switch type is the most efficient option.

When a recloser reaches its operation-count limit or is found to be significantly degraded or malfunctioning, it is replaced. The replacement programme is not presently targeting any specific asset type issues.

DISPOSAL

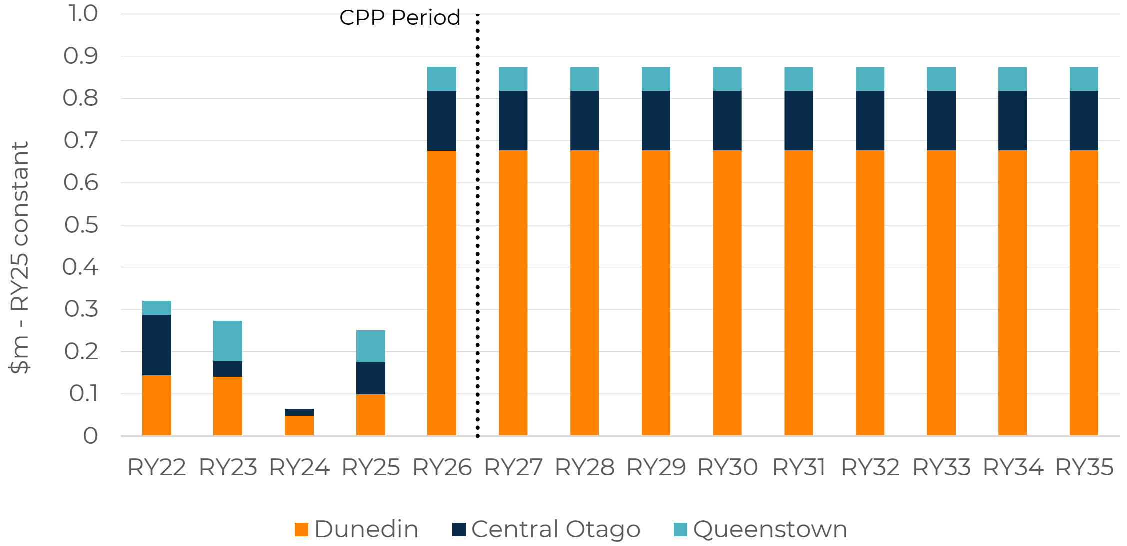
Removed assets not to be reused on the network may be retained as donor units for parts, where compatible makes and models are still in use on the network.

In the case of final disposal of units:

- Oil is recycled and reused
- Steel is collected by third-party scrap dealers

FORECAST EXPENDITURE

Figure 11-44: Capex forecast pole-mounted distribution switchgear by region (RY25 constant, $m)



11.7.3. LV enclosures

LV enclosures are used as the connection point on the network to supply domestic or small installations from the underground network and provide LV switching functionality. The fleet consists of approximately 26,800 LV enclosures, with 246 underground link boxes and 26,631 pillars.

Table 11-32: LV enclosure population by sub-network

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Link boxes	246	0	0	246
Pillars	9276	10673	6682	26631
Total	**9522**	**10673**	**6682**	**26877**

ASSET AGE

Our Fleet Strategy documents define a life expectancy of 40 years for our LV enclosures.

The average age of our LV enclosures is less than 20 years. This is because use of LV enclosures has increased substantially in recent years as new customers are increasingly supplied via underground cables in new subdivisions.

Figure 11-45 and Figure 11-46 show the age profiles of our low voltage pillars and link boxes, respectively.

Figure 11-45: Low voltage pillar age profile

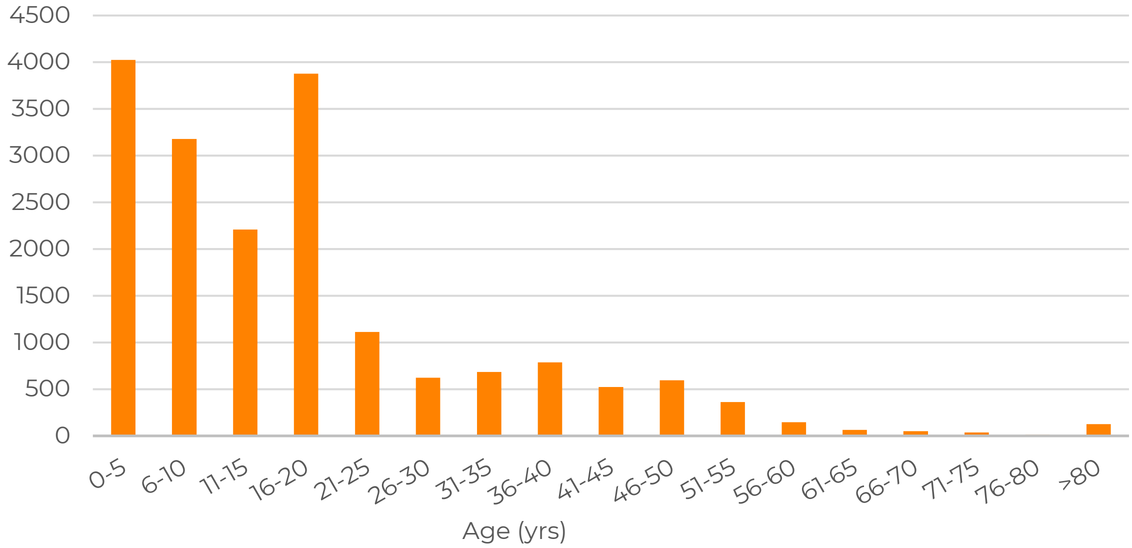
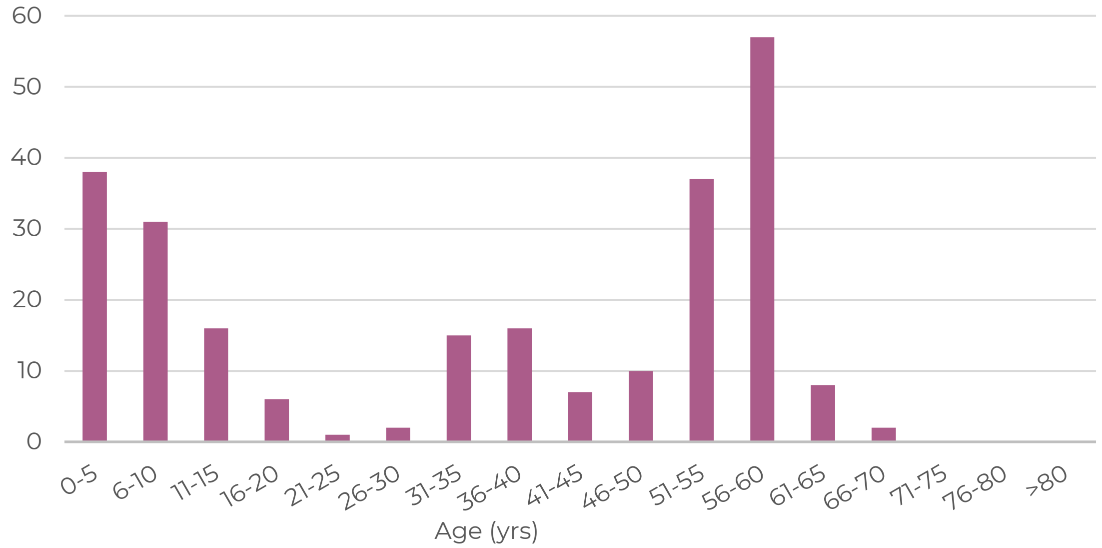


Figure 11-46: Low voltage link box age profile



ASSET HEALTH

We began assessing the condition of LV enclosures in RY19 and completed this inspection cycle in RY24. Through these inspections, we have obtained better LV enclosure condition data and have identified some assets for immediate replacement. Common defects include water ingress leading to corrosion and possible short circuits.

Through inspections, we found large numbers of pillars in unsuitable locations. Many have had retaining walls or fences built around or over them, and some have been buried in gardens, restricting access. These pillars will require relocation to be accessible.

Based on age, 11% of our LV enclosures have reached EOL. Most EOL enclosures are in the Dunedin sub-network, which also includes our underground link boxes. Our aged and inoperable underground link boxes present reliability and safety risks in the Dunedin CBD. The asset health of other LV enclosures appears to be relatively good, but there is a high reactive renewal component for these assets due to third-party damage.

Figure 11-47 and Figure 11-48 compare projected asset health of our LV pillars and LV link boxes in RY35 following our planned programme of renewals, with a counterfactual 'do nothing' scenario. A 'do nothing' approach would increase the percentage of H1 enclosures from 11% to 21%.

Figure 11-47: Projected low voltage pillar asset health

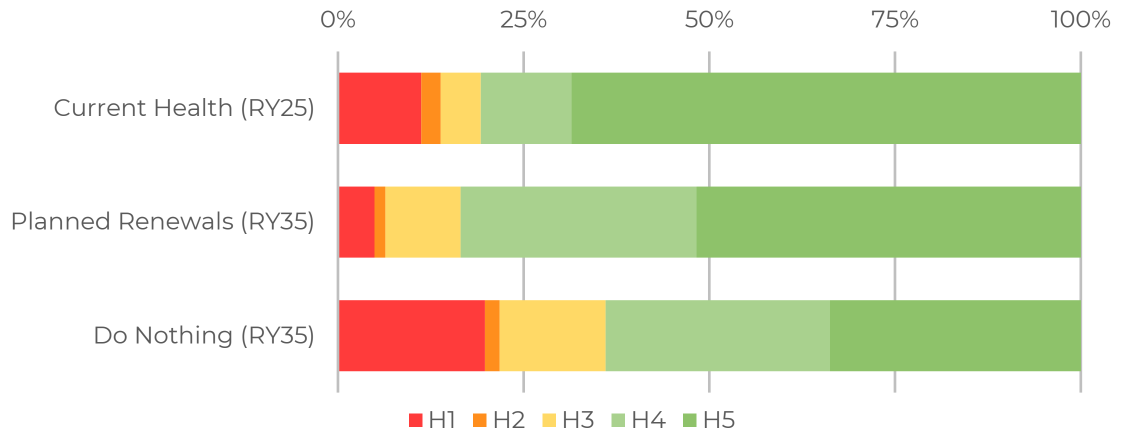
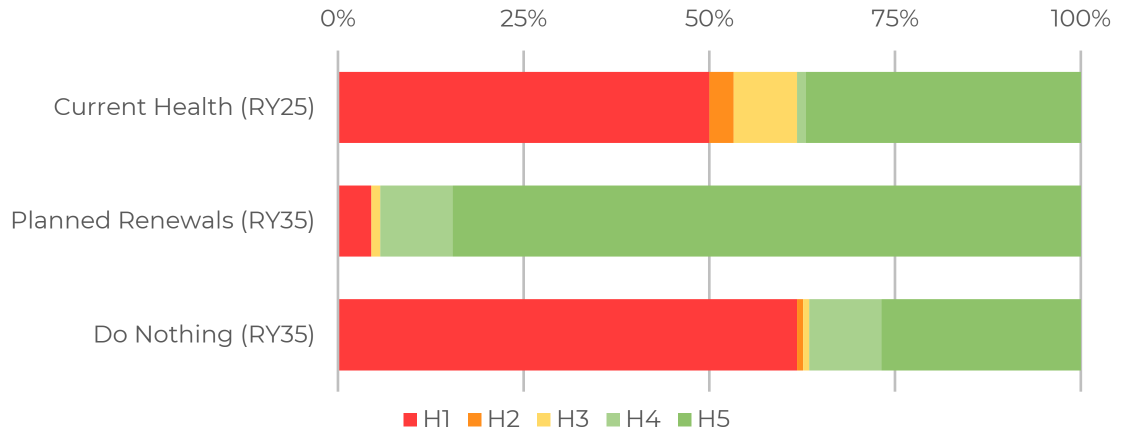


Figure 11-48: Projected low voltage link box asset health



ASSET PERFORMANCE AND RISK

We have not historically collected LV outage data, so we do not yet have reliability performance information for LV enclosures. However, we are presently gathering this fault information and building a database for analysis.

Results from the cycle of inspections completed thus far indicate that galvanised metal enclosures are subject to below-ground corrosion, while aluminium enclosures are subject to corrosion in acidic soils.

Table 11-33 summarises the key risks identified in relation to our LV enclosures fleet and their associated mitigations.

Table 11-33: Key LV enclosure risks and mitigations

Risk/Issue	Mitigation
Henley underground link boxes are degrading due to water ingress. These have safety issues including high arc flash potential and exposed terminals	Safety risks controlled by DNO Replacement programme
JW fuses are not operated due to safety issues (arc flash)	Safety risks controlled by DNO Future replacement programme
Steel pillars can be live due to high impedance faults (e.g. retaining screw from fuse loosening and touching cover)	Test before touch Inspection programme Corrective maintenance to retrofit plastic lids Replacement programme
Third-party damage/vandalism leaves pillars compromised	Inspection programme Public reporting Corrective maintenance Replacement programme

REPLACEMENT/RENEWAL

Our present approach to LV enclosure renewal is a combination of targeted and reactive replacement. We have targeted Waratah link boxes in Central Otago and JW fused P3400 metal boxes in Dunedin, which have operational restrictions on them due to inherent safety risks. We also replace LV enclosures reactively in the event of third-party damage. The actual programme of works is based on condition and defect data collected during asset inspections. Repair or replace decisions are dependent on the specific make and model of the enclosure and the defects found.

To provide guidance and criteria for consistent health grading, we recently published an inspection standard for LV enclosures. We commenced a new inspection cycle in RY25 based on this standard, with the inspection results to be uploaded into IBM Maximo, our AMSS. This data will provide the basis for our asset health and renewal forecasting, prioritising legacy types with known issues.

Options analysis on LV enclosures is relatively limited. It is technically preferable to replace underground link boxes with above-ground solutions, provided it is not cost prohibitive (in which case an underground replacement will be undertaken). For our other LV enclosures, if defects cannot be remediated onsite, the enclosure will be replaced with a new like-for-like or equivalent unit. With the above-ground solutions, some smaller LV enclosures that are 'clustered' together can be combined into a single larger capacity LV enclosure, which saves space and provides capacity and safe operation during faults.

DISPOSAL

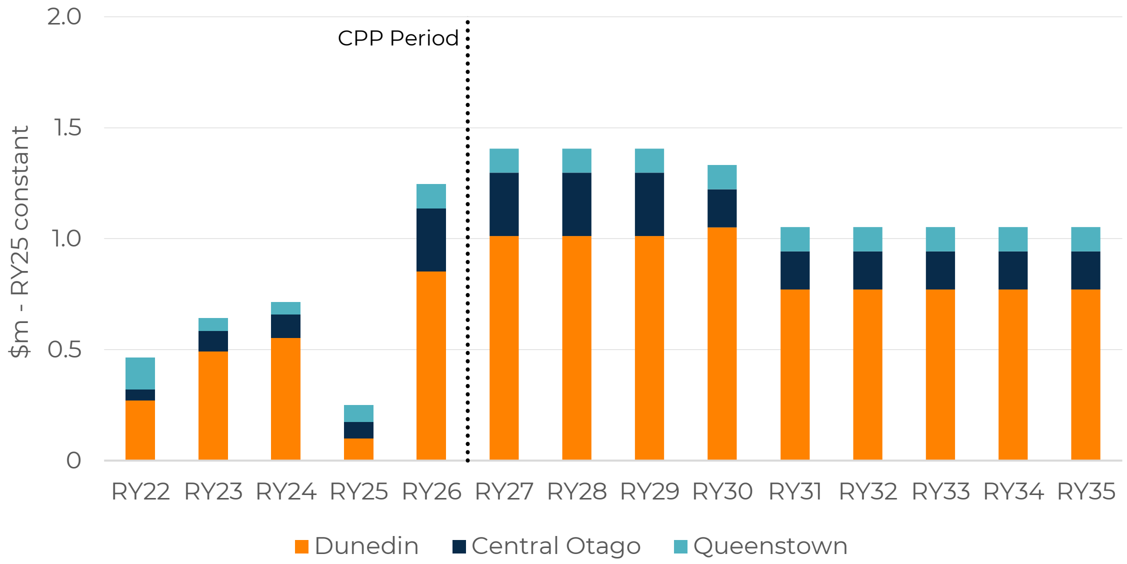
LV enclosures have no special disposal requirements.

FORECAST EXPENDITURE

Prior to RY20, our LV enclosure replacement levels were very low, as the risk of these assets was not fully understood and there was no dedicated programme. In RY20 we initiated a replacement programme and we now forecast renewal capex of approximately $12m during the planning period, as shown below, targeting JW fused and Waratah type enclosures first, after which we planned to move to an age-based approach. This expenditure includes any cable costs required to relocate enclosures for condition-based reasons (not customer driven).

As we begin to obtain inspection results based on our new inspection criteria, we expect a relatively high level of renewals – initially targeting specific assets relating primarily to legacy types with known issues, and then stepping to a steady state of renewals.

Figure 11-49: Capex forecast LV enclosures by region (RY25 constant, $m)



11.7.4. Underground distribution substations

Underground distribution substations are confined spaces below the street or footpath level of Dunedin CBD, accessible by ladder. Each underground distribution substation contains the usual distribution substation components of a (ground-mounted) distribution transformer, an RMU, and LV switchgear. This section is focused on the substation structure, while the internal assets are included in the relevant asset fleet sections.

ASSET AGE

We now have 16 underground substations located in the Dunedin CBD, and they are all older than 60 years.

ASSET HEALTH

Our underground substations have been assessed by an engineering design consultant for condition as well as fire, seismic, and reliability risk. The assessment found that all of the underground substations need to be replaced due to structural, water ingress/flooding, confined space, and condition issues.

ASSET PERFORMANCE AND RISK

The engineering report identified significant risk to both safety and reliability due to the deteriorated condition of the underground substations.

Table 11-34 sets out the key risks identified in our ancillary distribution substation fleet and their associated mitigations.

Table 11-34: Key ancillary distribution substation equipment risks and mitigations

Risk/Issue	Mitigation
Underground substations are confined spaces	Operational procedures
Flooding of underground substation	Sump pumps Audible float level alarms
Risks common to ground-mounted switchgear and distribution transformers (e.g. arc flash, inoperable JW fuses, etc.)	As identified in individual fleets
Securing an above-ground location to enable timely replacement	Design solution/alternative where viable, continued lines of communication with Dunedin City Council

REPLACEMENT/RENEWAL

All underground substations are planned for replacement. Each substation is considered individually to ensure an optimal network outcome with respect to safety and reliability, given the location of the substation.

Typically, an underground substation is replaced by a ground-mounted substation near the existing location so that it can be connected to the same point on the network with minimum changes to cable routes and other infrastructure.

However, if there is no obvious replacement site for an underground substation, we will assess additional options taking into account cost and risk mitigation effect. Options include:

- Locating a new above-ground site further from the existing site
- Decommissioning the existing site and reconfiguring the local network
- Refurbishing the substation's structure and installing a new transformer with switchgear above ground to minimise risk

Underground substation replacements are coordinated with underground link box replacements in the Dunedin CBD. We also coordinate underground substation replacements with works undertaken by the Dunedin City Council and other asset owners in the Dunedin CBD.

Replacement with above-ground assets reduces both the reliability and resiliency risk associated with flooding in the CBD area and the safety risks associated with working in confined spaces.

Our delivery team has been working with council to identify above-ground sites. This process has presented challenges and has had an impact on our ability to progress this work. This year we will work with the council to review the entire fleet and identify a plan for all sites, enabling us to progress sites that are less complex, while we work through a plan for the more challenging sites.

Current forecasts are based on establishing a suitable above-ground site to replace these underground assets.

DISPOSAL

Special consideration must be given to decommissioned underground substation sites, with regard to whether they will be retained as sites or filled in. This requires discussion with council and other asset owners in the Dunedin CBD.

FORECAST EXPENDITURE

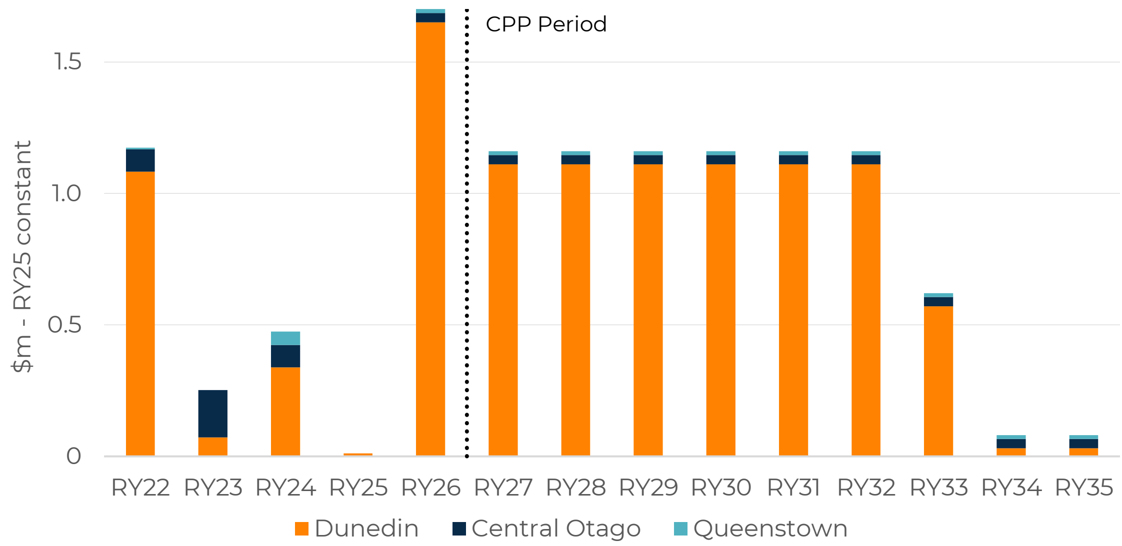
Our forecast renewal expenditure for underground substations is based on the replacement of a small number per year to create a steady programme of work. Undertaking more than a few replacements per year will likely lead to significant disruption to the CBD power supply and/or a loss of security of supply during construction of more than one site at a time.

We initially planned to replace all of our underground substations by RY30, but we have faced challenges in our efforts to secure sites for relocating the substations to above ground. As a result, we have only been able to replace two out of 18 substations to date.

Figure 11-50 below shows our current expenditure forecast for underground distribution substations, which will see all substations renewed by RY33.

We are in the process of reviewing the management of risk posed by continued operation of these substations, as well as options for reconfiguring the local network where above-ground relocation is a challenge, with the aim of expediting the renewal of the substations to meet our initial target of completing renewal by RY30.

Figure 11-50: Capex forecast ancillary distribution sub equipment by region (RY25 constant, $m)



11.8. DISTRIBUTION TRANSFORMERS

This section describes our distribution transformer portfolio and summarises how we manage the following asset fleets:

- Ground-mounted distribution transformers
- Pole-mounted distribution transformers
- Voltage regulators
- Mobile distribution substations and generators

11.8.1. Ground-mounted distribution transformer fleet

Ground-mounted distribution transformers are used to transform the voltage of electricity to a suitable level for customer connections, which is generally 400 V or 230 V. They are generally located in suburban areas and CBDs with underground cable networks. They range in size from smaller than 5 kVA to larger than 1.5 MVA. We have a small number of ground-mounted 11/6.6 kV auto transformers to interconnect parts of our distribution system that operate at different voltages.

Older ground-mounted transformers commonly have oil-filled or pitch-filled cable boxes with no integral fuses at either voltage. Modern ground-mounted distribution transformers may contain high voltage fuses in the high voltage cable box/end, and LV fuses or switchgear in the LV cable box/end. Modern ground-mounted transformers do not contain fluid-filled cable boxes. If a ground-mounted transformer with integral fuses and LV switchgear needs to be replaced, these integral components are also replaced.

Some older ground-mounted transformers are not cable-connected on the high voltage side, instead using solid busbars to connect to their respective RMU in a condensed 'package' distribution substation that has a very small footprint.

Table 11-35 gives an overview of our ground-mounted distribution transformer fleet by size and sub-network.

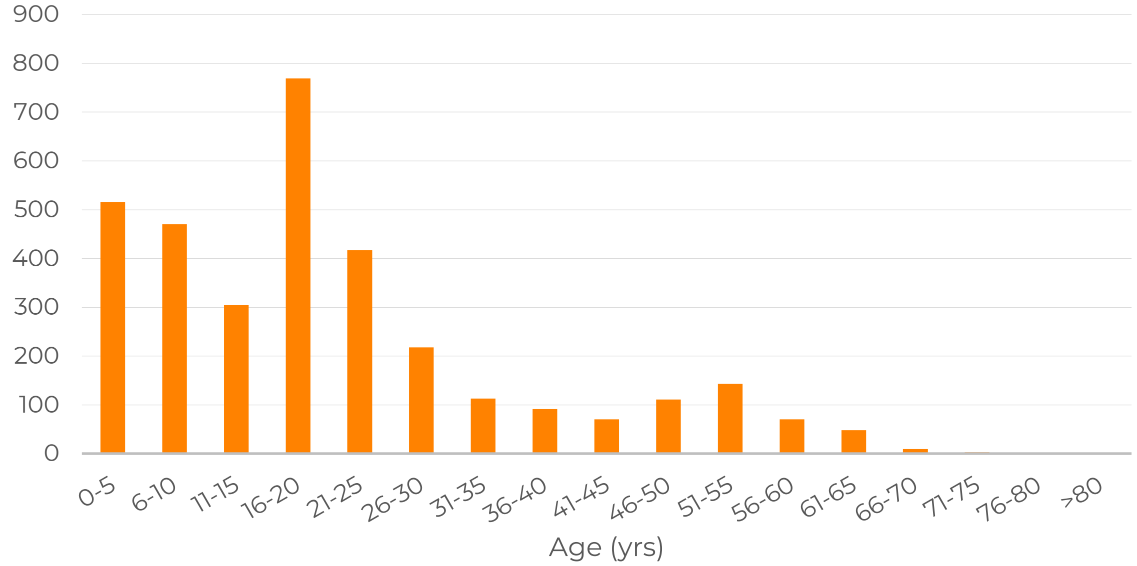
Table 11-35: Ground-mounted distribution transformer population by rating and sub-network

Rating	Dunedin	Central Otago & Wānaka	Queenstown	Total
0 to 100	164	873	495	1532
100 to 200	245	304	137	686
200 to 300	246	196	91	533
>300	360	141	133	634
Total	**1015**	**1514**	**856**	**3385**

ASSET AGE

Figure 11-51 shows the age profile of our ground mounted distribution transformers. The average age of our ground-mounted transformers is 22 years. There are relatively few transformers that will exceed their expected serviceable life of 70 years within the planning period.

Figure 11-51: Ground-mounted distribution transformer age profile



ASSET HEALTH

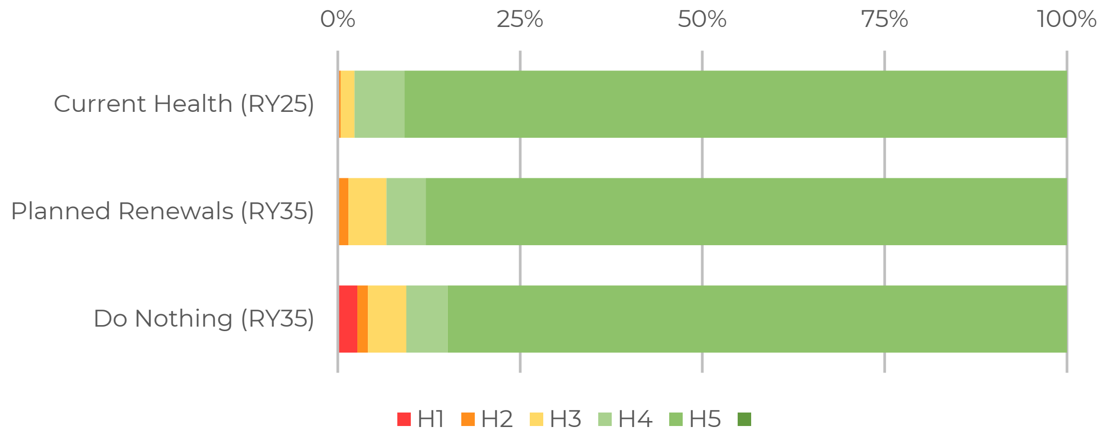
We do not have a high level of confidence in the historic asset condition data related to this fleet, as historically we have not had consistent condition assessments to inform asset AHI. As a result, the AHI of this fleet is largely informed by age and the expected asset serviceable life.

In 2024 we progressed work to enhance the data incoming from inspections to enable us to transition to a condition-based renewal plan, and published an inspection standard. As we mature in our understanding and management of asset risk, we continue to refine our methods of assessing asset health, including incorporation of enhanced condition data from our new inspection standard. This inspection standard will ensure all assets receive a consistent assessment of asset condition. We will use results from these inspections to inform a structured and quantitative approach to assessing the condition, ultimately enhancing our risk-based decision-making with regard to expenditure.

Some ground-mounted distribution transformers are installed in old Aurora Energy-owned buildings, which are in a poor state and will not meet today's seismic standards. The buildings will be assessed and defects addressed to ensure they remain suitable for use for the remaining life of the assets they house. When renewing assets in such buildings, we will evaluate whether it is necessary to replace, strengthen, or modify the buildings to ensure they comply with current standards.

Figure 11-52 shows the AHI for ground-mounted distribution transformers.

Figure 11-52: Projected ground-mounted transformer asset health



ASSET PERFORMANCE AND RISK

Having completed a fleet strategy and documented all plausible failure modes for this fleet, we recently developed and published an inspection standard.

A benefit of ground-mounted distribution transformers is that they are inherently more seismically robust than pole-mounted transformers; however, they still require seismic restraint. RCA investigations to date have not identified any systemic issues with this fleet.

Table 11-36 sets out the key risks identified in our ground-mounted distribution transformer fleet and their respective mitigations.

Table 11-36: Key ground-mounted distribution transformer risks and mitigations

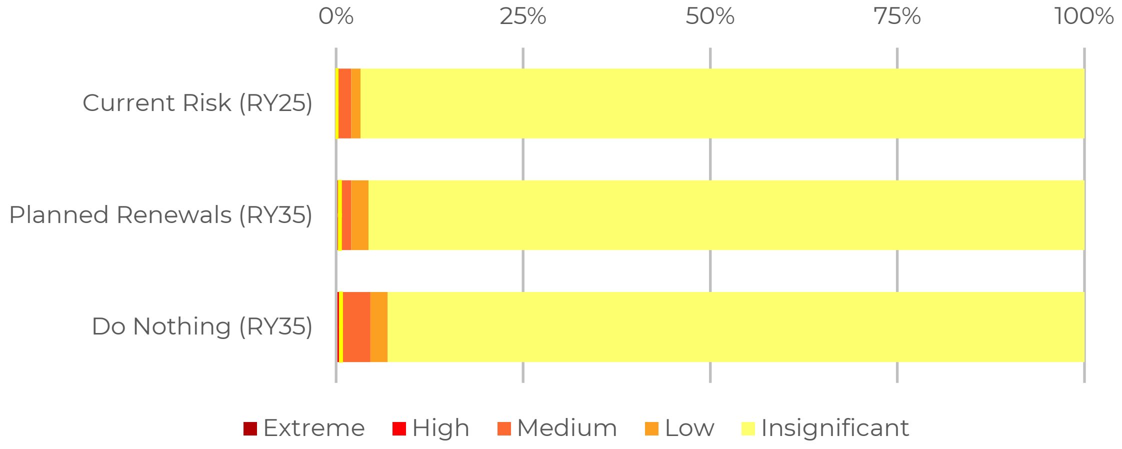
Risk/Issue	Mitigation
Flooding	Regular inspection, relocation/elevation
Animal/insect infestation	Inspection and treatment
Vegetation growing around the transformer	Inspection, vegetation management
Earthing issues	Inspection, testing
Signage, labels, and security	Inspection, defects reporting
Corrosion and deterioration of rubber components resulting in oil leaks, as well as ingress of moisture and other contaminants into the oil, thereby accelerating internal deterioration	Inspection, testing, replacement
Third-party damage, mechanical failure due to internal ageing and corresponding lack of fault current withstand, or thermal failure due to overloading	Inspection, defects reporting

We took learnings from RCA outcomes into account in the production of our new Distribution Transformer Inspection Standard, which sets forth inspection criteria designed to identify early signs of failure and initiate appropriate corrective action. The standard also provides guidance on how to assess and grade asset condition.

Risk is informed by asset health and asset criticality, and our risk framework generates AHI vs criticality for each distribution transformer. The criticality of a transformer is determined based on the consequence of failure with regard to public safety. Aurora Energy's network is divided into safety criticality zones depending on the nature of the load supplied and activities in the respective area.

Figure 11-53 shows the projected risk for our ground-mounted distribution transformers. While a very large proportion of our fleet presents an insignificant risk, a small number of renewals will be required in the planning period to keep risk within tolerable levels.

Figure 11-53: Projected ground-mounted distribution transformer risk



REPLACEMENT/RENEWAL

We prioritise replacement, with remaining asset life and current health constituting the key considerations. We take into account the following strategic considerations:

- Transformers at 80% to 100% utilisation (normal transformer loading) will have an MPL of 70 years.
- Transformers at 130% and greater utilisation are replaced as a planning function.
- Ground-mounted transformers greater than or equal to 500 kVA at 100% to 130% utilisation with age between 30 and 60 years old are subject to a TCA assessment.
- We coordinate ground-mounted transformer replacements with ground-mounted distribution switchgear replacements, as appropriate.
- Some ground-mounted distribution transformers are installed in old Aurora Energy-owned buildings, which are in a poor state and will not meet today's seismic standards.

Our planned work programme will enable us to maintain our H1-classified transformers at a low level. However, our population of H3 assets – those for which replacement within 10 years is required – will increase over the period as the fleet ages. The outcomes with respect to AHI and risk are shown in Figure 11-52 and Figure 11-53 above.

DISPOSAL

We dispose of ground-mounted distribution transformers when they are decommissioned. The principal components – steel, copper, and oil – are recycled. We retain fibreglass enclosures from certain types of ground-mounted transformers as spares, depending on their condition.

When units have oil leaks that can be repaired in a workshop, a corrective maintenance task of swapping the existing transformer with a like-for-like spare replacement is often cost-effective. Consideration must be given to factors such as the transformer's loading (whether its capacity is still sufficient for the expected remaining life) and the condition of any co-located equipment such as RMUs, which, if also in poor condition or of a certain type, may justify a total replacement solution.

We also consider whether the load supplied by the transformer can be shifted to other nearby substations to allow it to be decommissioned.

FORECAST CAPEX EXPENDITURE

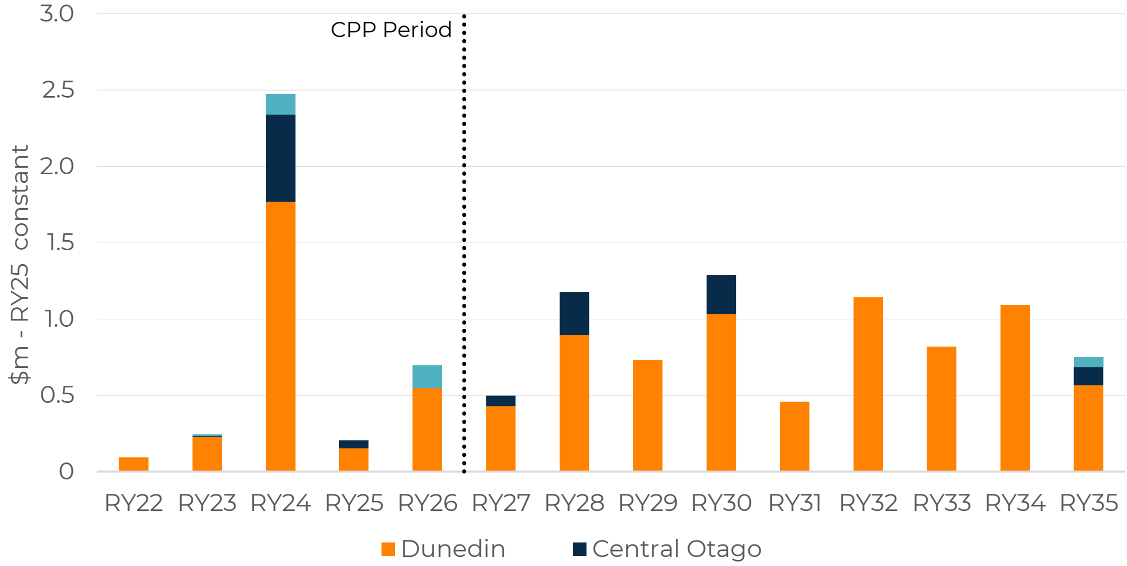
Due to the general health of the fleet, we have not replaced many ground-mounted distribution transformers in recent years except in RY24, when we spent $2.5m on renewals. While the total forecast expenditure over the planning period is $8.7m, results from our new cycle of transformer inspections will have an impact on further forecasts as we understand asset health better and plan accordingly.

Going forward, as we begin to receive inspection results based on new inspection criteria, we expect a high level of renewals initially targeting specific assets due primarily to obsolescence, age and condition, followed by a shift to a steady state of renewals.

The key benefit of our planned renewal programme is ensuring continued reliability of service to consumers. Secondary benefits are mitigation of low probability safety incidents arising during transformer failures and mitigation of the environmental risk of oil spills from aged or failed transformers – and accordingly, ensuring the security of the asset.

Our current forecast renewal capex for ground-mounted distribution transformers is shown in **Figure 11-54**. This forecast will be adjusted as we receive condition data.

Figure 11-54: Capex forecast ground-mounted distribution transformers by region (RY25 constant, $m)



11.8.2. Pole-mounted distribution transformer fleet

Pole-mounted distribution transformers, like ground-mounted transformers, are used to transform the voltage of electricity to a suitable level for consumer connections. Pole-mounted units are generally smaller than ground-mounted units. The majority of the population is smaller than 100 kVA, but they can be up to 500 kVA (pedestal-mounted).

Pole-mounted transformers are usually located in rural or suburban areas with lower customer densities and smaller loads. We have a small quantity of single wire earth return (SWER) transformers supplying SWER systems in our Dunedin sub-network. A small number of pole-mounted 11/6.6 kV auto transformers are used to interconnect parts of our distribution system that operate at different voltages.

Table 11-37 gives an overview of our pole-mounted distribution transformers fleet by size and sub-network.

Table 11-37: Pole-mounted distribution transformer population by rating and sub-network

Rating	Dunedin	Central Otago & Wānaka	Queenstown	Total
≤100	1331	1836	459	3626
>100	343	29	5	377
Total	**1674**	**1865**	**464**	**4003**

ASSET AGE

Figure 11-55 and Figure 11-56 show the age profiles of our pole-mounted distribution transformers below 100 kVA and above 100 kVA, respectively. The average age of the fleet is 36 years. Given their 70-year expected life, 9% of pole-mounted transformers have already exceeded their expected life; and by the end of the planning period, this will have increased to 16.1% if no action is taken.

Figure 11-55: ≤100 kVA pole-mounted distribution transformer age profile

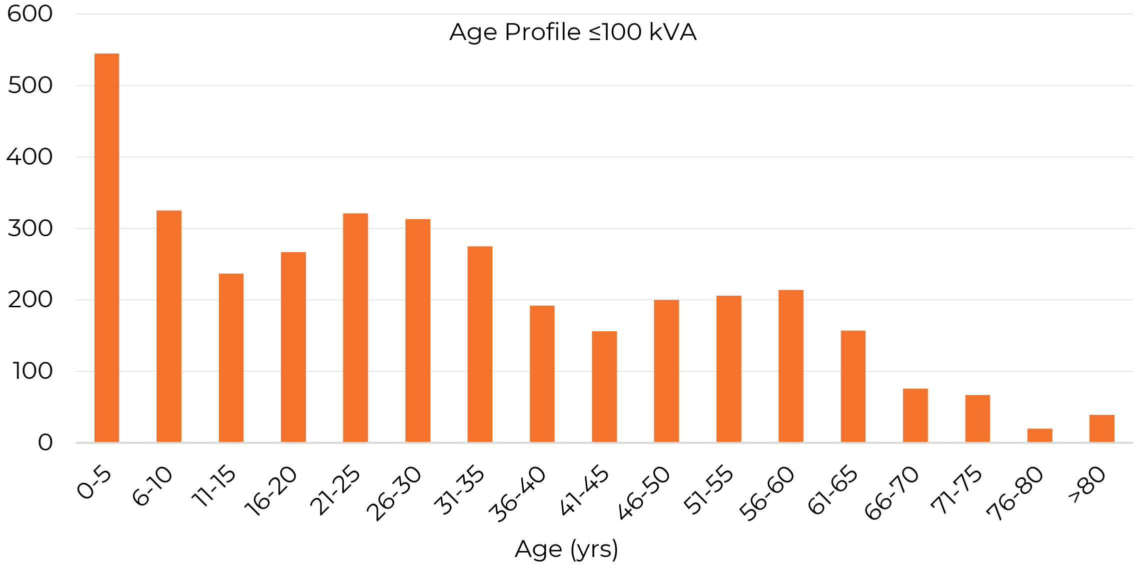
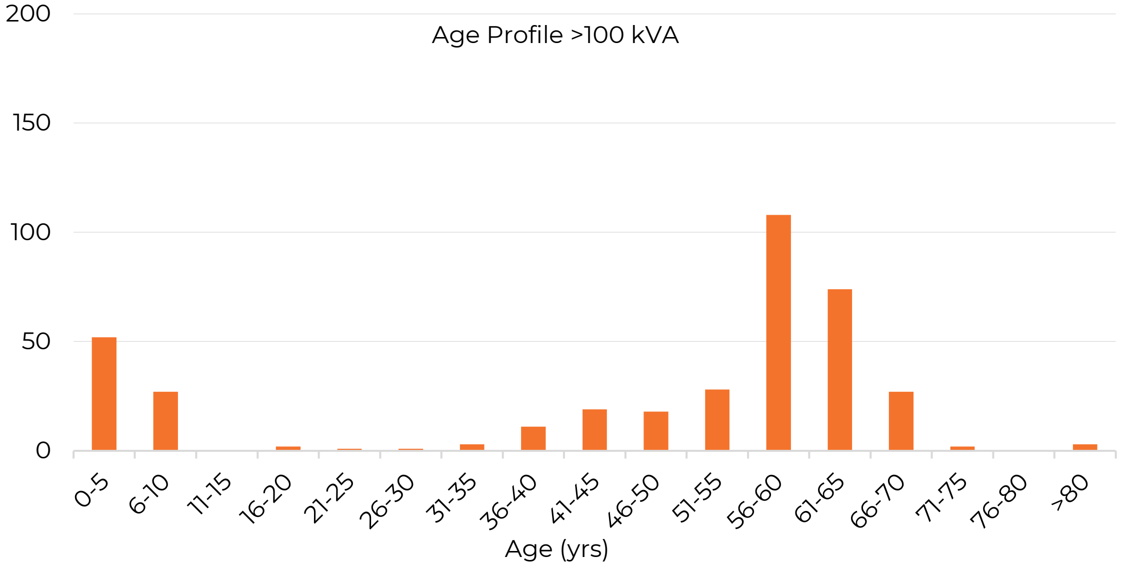


Figure 11-56: >100 kVA pole-mounted distribution transformer age profile



ASSET HEALTH

We do not currently have a high level of confidence in the asset data related to our pole-mounted distribution transformers, as historically we have not systematically captured and recorded condition information. As a result, the AHI of this fleet is largely informed by age and the expected asset serviceable life. However, where we have additional condition data, we are able to override the AHI and replacement date within the fleet strategy to improve the accuracy of our forecast.

As a result of an update to our asset fleet strategy, all pole-mount transformers are now subject to a visual inspection as part of the overhead inspection programme. Transformers that are greater than 100 kVA will undergo detailed five-year cyclic inspections.

The ongoing progress of maturing and refining our inspection programme will provide the information we need to continue our progress toward a more condition-based approach. We will use this data to continually refine our assessment of health and risk, including how we plan and prioritise renewals.

Figure 11-57 and Figure 11-58 show the current and projected AHI of the fleet, along with the expected health under a 'do nothing' scenario.

Currently, 4% of the fleet is classified as H1 (replace within one year). The current overall health profile depicts a backlog situation, which results from the largely age-driven model. While the asset health degrades over the period due to a number of assets reaching the end of their MPL, the resulting AHI profile is significantly better under the proposed expenditure programme than the 'do nothing' scenario, where the proportion of H1s would increase to 17.6%.

Figure 11-57: Projected ≤100 kVA pole-mounted distribution transformer asset health

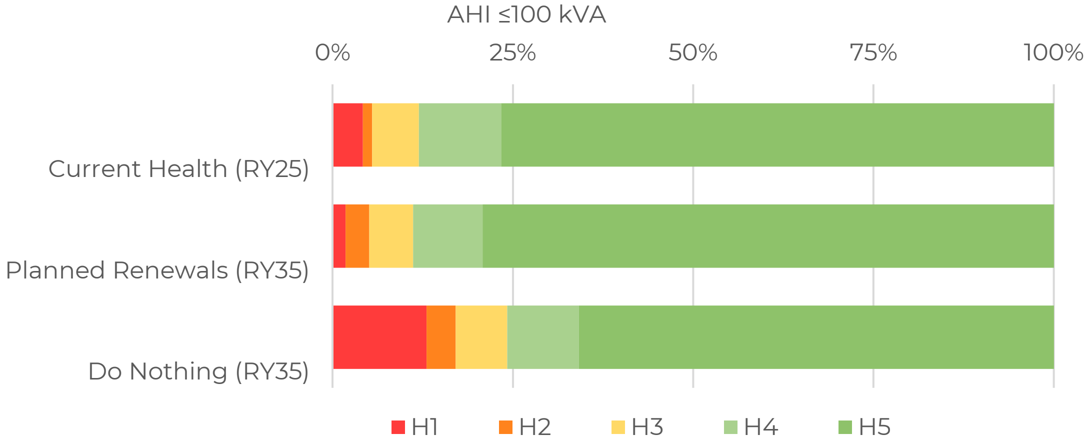
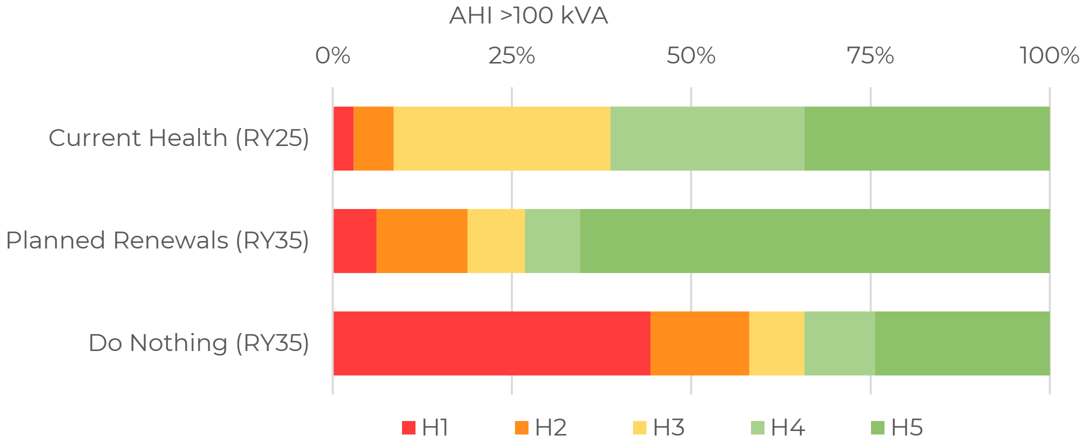


Figure 11-58: Projected >100 kVA pole-mounted distribution transformer asset health



ASSET PERFORMANCE AND RISK

Having completed the fleet strategy and documented all plausible failure modes for this fleet, we are in the process of updating our inspection standard. RCA investigations have not identified any systemic issues with this fleet to date. Table 11-38 sets out the key risks identified in our pole-mounted transformer fleet and their associated mitigations.

Table 11-38: Key pole-mounted transformer risks and mitigations

Risk/Issue	Mitigation
Third-party damage (car vs pole)	High visibility reflectors on poles Design choice regarding pole location
Seismic risk: older pole-mounted units, especially two-pole substations, are not compliant with modern seismic standards	Replacement plan Pole-mount to ground-mount conversions
Electrocution risk from public accessing or contacting low-mounted distribution transformers e.g., via orchard equipment	Identifying locations of low-mounted transformers through inspections Replacement of low sites Signage and discussion with landowners in interim
Vegetation growing around or into the transformer	Inspection and maintenance, vegetation management
Earthing issues	Inspection and testing
Corrosion and deterioration of rubber components resulting in oil leaks. This also enables ingress of moisture and other contaminants into the oil, which accelerates internal deterioration.	Inspection, testing, maintenance, and renewal
Mechanical failure due to internal ageing and corresponding lack of fault current withstand	Inspection, testing, maintenance, and renewal
Thermal failure due to overloading	Inspection, testing, maintenance, and renewal

REPLACEMENT/RENEWAL

We forecast the required budget and expected volumes for replacement of pole-mounted transformers based on our AHI and risk assessment methodology. This currently focuses on age but can be adjusted based on actual condition data where known. The actual programme of works is based on condition assessment undertaken during asset inspections and is prioritised based on our risk framework.

Distribution transformers of 100 kVA and below are categorised as small transformers. We generally replace these units reactively upon failure or when the associated pole is being replaced, if the transformer is more than 50 years old. This approach is cost-effective and limits the impact on consumers, and modelling in our fleet strategy indicates that it achieves a steady state of fleet health. We have recently replaced a large number of these transformers during pole replacements and this will continue, albeit at a lower rate. When establishing our forecasts for this fleet, we use historical replacement rates along with identification of transformers that will be replaced as associated assets, to inform quantities over the period.

The AHI profile of the fleet is declining, with multiple units having already exceeded their life expectancies. As such, it is essential that we take a more proactive approach (for transformers greater than 100 kVA). This will involve proactive replacement of larger, aged pole-mounted units (which present a specific public and worker safety risk) with ground-mounted units, alongside condition-based replacement of other pole-mounted units.

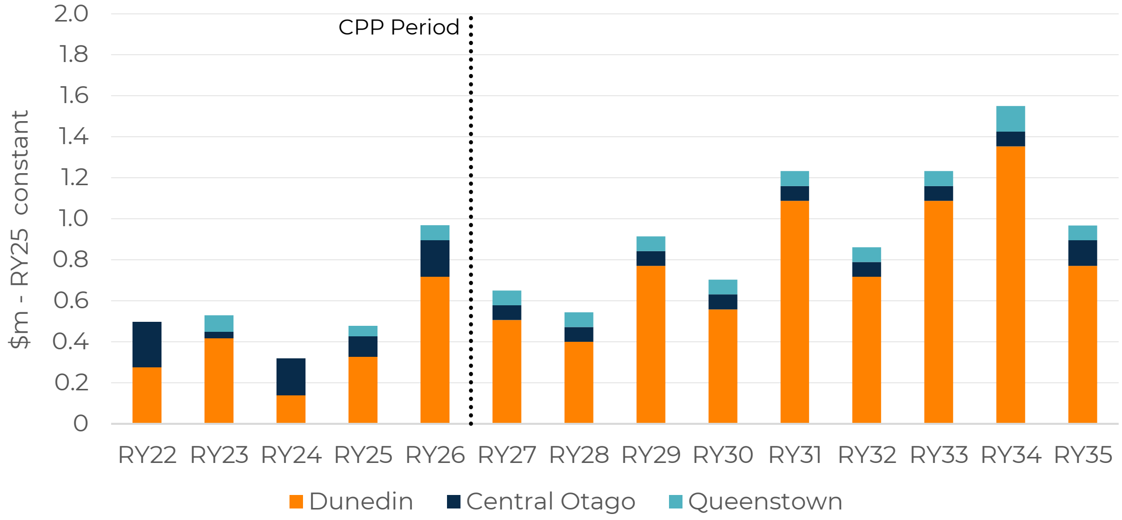
Where replacement is required, our preferred option is to retain pole-mounted transformers where possible. This is supported by consultation with communities on the price implications of underground conversions for visual amenity reasons. We also consider offloading and decommissioning when assessing options for replacement of pole-mounted distribution transformers.

DISPOSAL

The disposal process for pole-mounted transformers is similar to that for ground-mounted transformers.

FORECAST EXPENDITURE

Figure 11-59: Capex forecast pole-mounted transformers by region (RY25 constant, $m)



11.8.3. Other distribution transformers

VOLTAGE REGULATORS

Voltage regulators are designed to automatically maintain voltage at a set level on our 11 kV or 6.6 kV network. The length and conductor size of some of our 6.6 kV and 11 kV feeders necessitates the installation of voltage regulators partway along feeders to maintain the correct voltage at the end of the feeder.

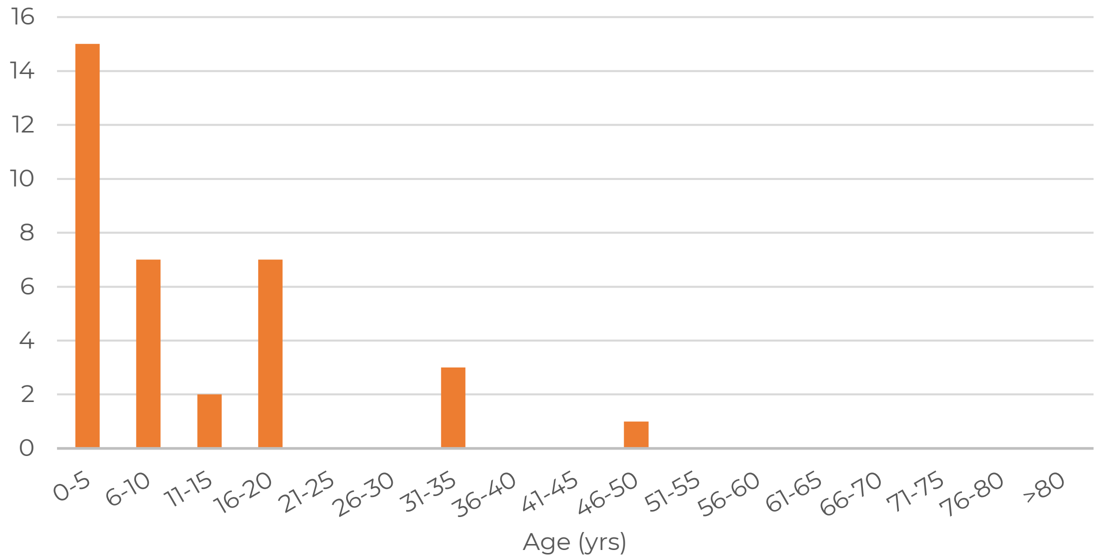
Voltage regulators comprise an auto transformer, a control device, and communications to our SCADA system. While our fleet of voltage regulators is primarily controlled by digital controllers, a few older controllers with ad-hoc setups and limited visibility of settings remain in service.

We have a total of 41 voltage regulators, of which 39 are in Central Otago, 2 are in Dunedin, and 8 are in Queenstown. These units are either three-phase units or single-phase units making a three-phase voltage regulation site.

ASSET AGE

The majority of our voltage regulators were installed in the last 15 years. Voltage regulators have an expected life of 55 years. None of our voltage regulators will exceed their expected life during the AMP forecast period.

Figure 11-60: Voltage regulator age profile



ASSET PERFORMANCE AND RISK

Our voltage regulators are generally performing well. This fleet has two main performance issues/risks:

- We have isolated problems with some controllers from our voltage regulator fleet, and the Cooper Power Systems KYLE F6-P2B control units are no longer supported by the manufacturer.
- In some sites, regulators have not been set up correctly or different voltage regulators from the same 'set' have been used across different sites, resulting in impedances that do not match and potential operational issues.

Table 11-39 sets out the key risks identified in our voltage regulator fleet and their associated mitigations.

Table 11-39: Key voltage regulator risks and mitigations

Risk/Issue	Mitigation
Oil leakage into environment	Maintenance and replacements
Third-party damage or access	Installation of visible warning signs Locks and inspections Design choice of location
Electrocution risk from public accessing or contacting low-mounted voltage regulators	Identifying locations of low-mounted voltage regulators through inspections Replacement of low sites
Voltage regulator failure due to age-related internal failure	Strategic spares Replacement plan
Voltage regulator noise complaints	Inspections and follow-up actions Replacement plan
Voltage regulator explosion, either due to active part failure, bushing failure, or cable box failure	Maintenance and replacements Safety-in-design solutions e.g. consider location and whether dry-type or non-flammable oil is appropriate
Vegetation restricting access to voltage regulator	Inspections and corrective maintenance
Poor or missing earth connections	Periodic earth testing Corrective maintenance
In service failure or forced outages leads to non-compliant voltage	Inspection, preventive maintenance, and replacement plan
Lack of easement on sites installed post-1992	Obtain easement Choose new site chosen when renewing or add a bypass if an easement cannot be obtained on the existing site
Mismatched sites losing synchronism, leading to non-compliant voltage	Overall plan to 'rematch' sites across the network and revisit settings to ensure voltages are compliant
Having four different rating sizes on the network expands the number of spares required to be carried and diminishes the flexibility to rotate units around sites	Standardise on one or two rating sizes Obtain approval to hold strategic stock of complete units for the one or two sizes chosen Generic construction across future sites so that rotation of units becomes a 'plug and play' situation rather than a rebuild challenge

REPLACEMENT/RENEWAL

Voltage regulators have an expected life of 55 years, but we expect those in higher corrosion areas will deteriorate more quickly. Achieving expected life assumes regular maintenance, which has not typically occurred in the past. Voltage regulators running abnormally will likely not achieve their expected life, such as units at sites running at high loadings, mismatched single-phase units, or units that are performing additional tapping. As a result, we may replace some units based on adjusted life expectancies.

The key considerations for prioritisation of replacements are AHI and asset criticality. The focus of our future renewal plan is on:

- Replacing voltage regulators at the Cardrona site as they are no longer fit for purpose.

- Replacing the voltage regulator at the Macandrew Bay site in RY31. This was installed in 1976 and may have been second-hand at that time. The site also has the challenge of being a 3 MVA three-phase ground-mount site, so a future needs case will need to be completed to clarify requirements.
- Replacing obsolete controllers with the newer manufacturer-supported CL7 control unit.
- 'Rematching' all sites with single-phase voltage regulators to ensure each site is operating correctly and has equal impedance.

DISPOSAL

We dispose of voltage regulators when it is no longer economic to refurbish them. As part of the decommissioning process, we retain replaceable components that are known to fail or wear, as spares. The remainder of the unit's principal components of steel, copper, and oil are recycled.

FORECAST CAPEX EXPENDITURE

The forecast expenditure allows for replacement of two units in RY31: one in Cardrona and one in Dunedin.

MOBILE DISTRIBUTION SUBSTATIONS AND GENERATORS

Mobile distribution substations are used to bypass permanent 11 kV or 6.6 kV distribution substations, to enable planned work to proceed without significant loss of supply to consumers. These assets are also used as backup transformers in the event of a distribution transformer failure. Our mobile distribution substations consist of HV and LV cables, an RMU, a transformer, an LV switchboard, and the truck and body housing all these components.

The purpose of mobile diesel generators is to reduce the impact of planned outages on consumers. We also have standby generators to supply our Dunedin and Central Otago control rooms in the event of a loss of network supply.

ASSET AGE

We have three mobile distribution substations. One has a transformer capacity of 300 kVA and two are 500 kVA. They are ageing, having been purchased in the 1980s, but are in acceptable working order.

Our mobile generator fleet consists of three 100 kVA generators and one 300 kVA generator, all of which were purchased in 2019 and are in good condition.

We have a nine-year-old standby generator at Glenorchy. Our standby generators supporting our Dunedin and Central Otago control rooms were installed in 2017 and 2019, respectively.

ASSET PERFORMANCE AND RISK

Table 11-40 shows the failure risks and associated mitigations for our mobile distribution substation and generator fleet.

Table 11-40: Key mobile distribution substation and generator fleet risks and mitigations

Risk/Issue	Mitigation
Arc flash from failure of Statter RMU in mobile distribution substation	Lanyard operating system
Injury from falling off mobile substation	Edge protection system installed on top when in use

REPLACEMENT/RENEWAL

Due to arc flash levels for the mobile distribution substations, the RMUs must be operated at a distance, via a lanyard system. With the old age of the trucks, we have had rust issues that require ongoing repairs to obtain a certificate of fitness (COF). An LV board upgrade is soon due on the 300 kVA mobile distribution transformer.

We plan to investigate options for replacing the mobile distribution substations in the medium term. To reduce the carbon footprint of our diesel generators, we have started reaching out to green energy providers to explore options such as a hydrogen hybrid and biodiesel.

We will replace our mobile distribution substations and mobile generators when their condition becomes poor, when they become uneconomic to maintain or too unreliable to operate, or when they begin to present a significant safety risk.

11.9. SECONDARY SYSTEMS

This section describes our secondary systems portfolio and summarises how we manage the following asset fleets:

- Protection systems
- DC systems
- Remote terminal units
- Metering and power quality monitoring
- Communications assets

Secondary systems are essential for the safe and reliable function of the network, playing a critical role in maintaining its overall integrity. They typically have shorter service lives and are low-cost compared to primary plant components.

These systems provide various functions, and include protection systems for rapid fault detection and safe zone substation operations; DC systems, which ensure power supply in the absence of AC; and RTU assets, which provide network visibility and remote control, allowing efficient and effective network management. Further, metering assets, such as check meters, are crucial for revenue metering and load control, while power quality meters are necessary for statistical analysis of network performance and compliance with electricity codes.

11.9.1. Remote terminal unit (RTU) fleet

RTUs are an integral component of our supervisory control and data acquisition (SCADA) and telemetry system, providing communication with intelligent electronic devices (IEDs) in zone substations. The RTUs are used to furnish information for network operations and control, perform ripple injection, and provide an automation platform to manage capacitor bank switching and auto-changeover schemes. They also allow us to implement specialised protection schemes during contingency situations.

While the majority of our RTUs are situated in zone substations and GXPs, some are installed in outdoor locations. Our SCADA system and RTU fleet are generally in good condition. As such, we are now in steady-state and do not have any significant work planned in this portfolio over the planning period.

We have a total of 73 RTUs across our network. This fleet comprises units from three different manufacturers: SEL Axion, Abbey, and Schneider. All RTUs are equipped with DNP3 functionality, which we have standardised with our SCADA master station. We plan to exclusively use SEL RTUs for substation applications, and we have scheduled renewals and upgrades as part of capital works. The ripple injector controller – currently a modified version of Abbey – is facing technological obsolescence and we plan to upgrade it with a more modern injection controller from Swistec during the planning period. We have spare units available to address any potential RTU or ripple injector failures.

ASSET AGE

Some of our RTUs have exceeded their expected life of 15 years, though most are less than 20 years old. RTUs replaced 7 to 8 years ago as part of our SCADA upgrade are evident in the age profile. The majority of our RTUs are modern and provide an adequate level of operational performance. We have adopted good industry practice and our devices use standard DNP3 protocol over TCP/IP communication to our SCADA master station. We have refurbished a few of our older RTUs to enhance their operational performance and also to extend their support for TCP/IP communication. We have two legacy RTUs dedicated to 6.6 kV ripple injection, which we plan to fully decommission by the end of RY28.

Table 11-41: RTU asset population by sub-network

	Dunedin	Central Otago & Wānaka	Queenstown	Total
RTU	28	25	16	69
Ripple Controller	5	2	1	8
Total	**33**	**27**	**17**	**77**

Figure 11-61: RTU age profile

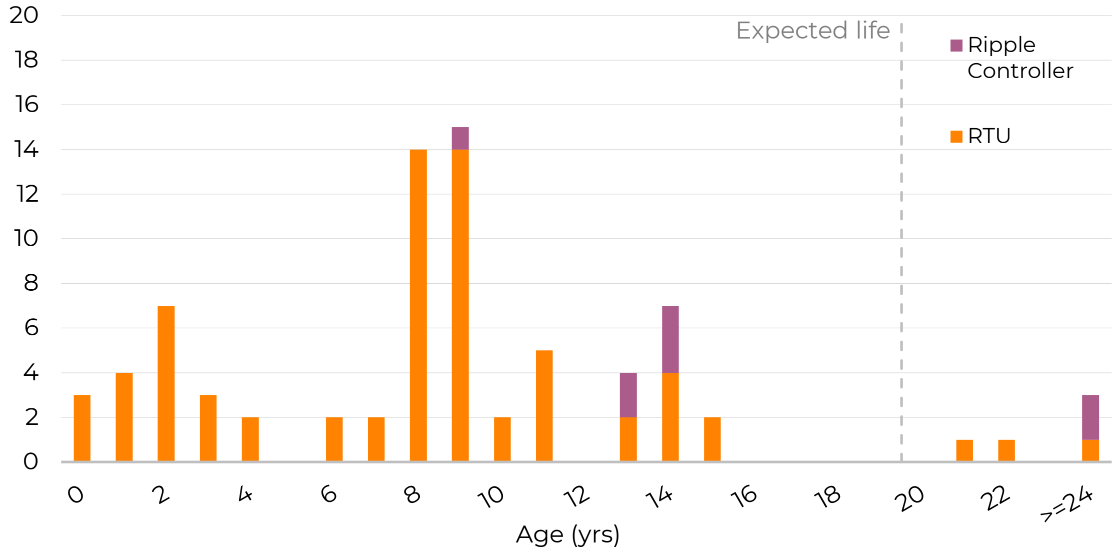
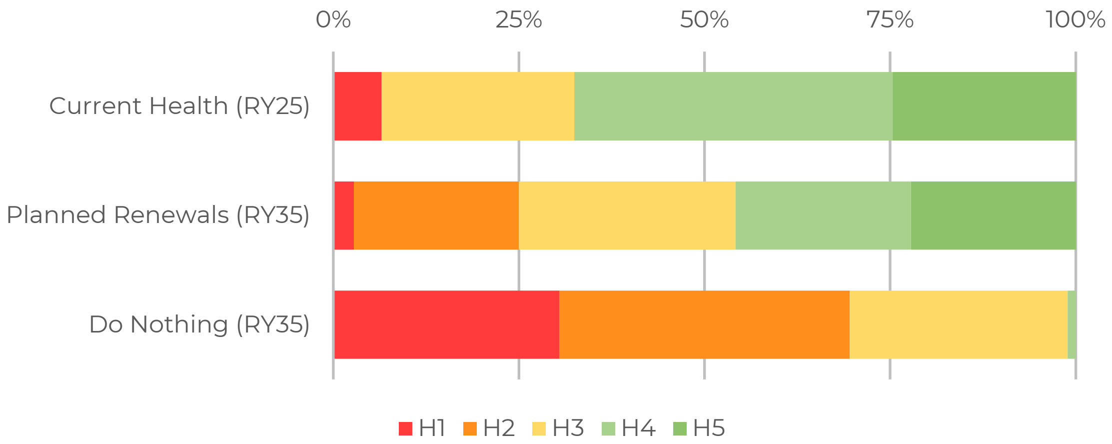


Figure 11-62: Projected RTU asset health



ASSET HEALTH

It is not practical to obtain condition information on RTUs, due to their electronic nature. Instead, we use age as a proxy for condition. Based on this, our RTU fleet is in generally good condition.

The key driver of expenditure for RTUs is technological obsolescence. Where manufacturers notify us that they are going to discontinue support for specific RTU hardware, we manage the risk of unplanned failures by stocking spare parts.

ASSET PERFORMANCE AND RISK

The performance of our RTUs is satisfactory and we have not identified any issues. Our standard design includes dual communication paths, which means it is rare for us to lose communication between our master station and zone substation RTUs. Some of the RTUs in the Central Otago & Wānaka and Queenstown sub-networks are limited in their hardware and software capabilities, providing only serial communication to IEDs and a fixed number of hardwired input and output contacts, and being unable to transmit the present time-stamps to the IEDs.

Table 11-42 sets out the key risks identified in relation to our RTU fleet and their associated mitigations.

Table 11-42: Key RTU system risks and mitigations

Risk/issue	Mitigation
RTU malfunction or failure in service leads to lack of remote control or indication	Inspection and testing regime Alarms and monitoring Age-based replacement

REPLACEMENT/RENEWAL

Alternatives to complete renewal of RTUs when they reach EOL are limited. We have implemented firmware updates and CPU upgrades to prolong the operational life of older RTUs wherever applicable.

RTU works undertaken as part of zone substation projects are inherently prioritised on a risk basis. RTU replacements outside the zone substation programme are relatively limited at present, and criticality has not yet been factored into planning of these works.

During the planning period, we primarily replace RTUs as part of wider zone substation works. We also replace RTUs as they become technologically obsolete, using age (versus expected life) as a forecasting proxy for obsolescence, as well as end of support notices from vendors.

Where possible, we coordinate the replacement of RTUs with other project works, such as zone substation and protection renewals.

DISPOSAL

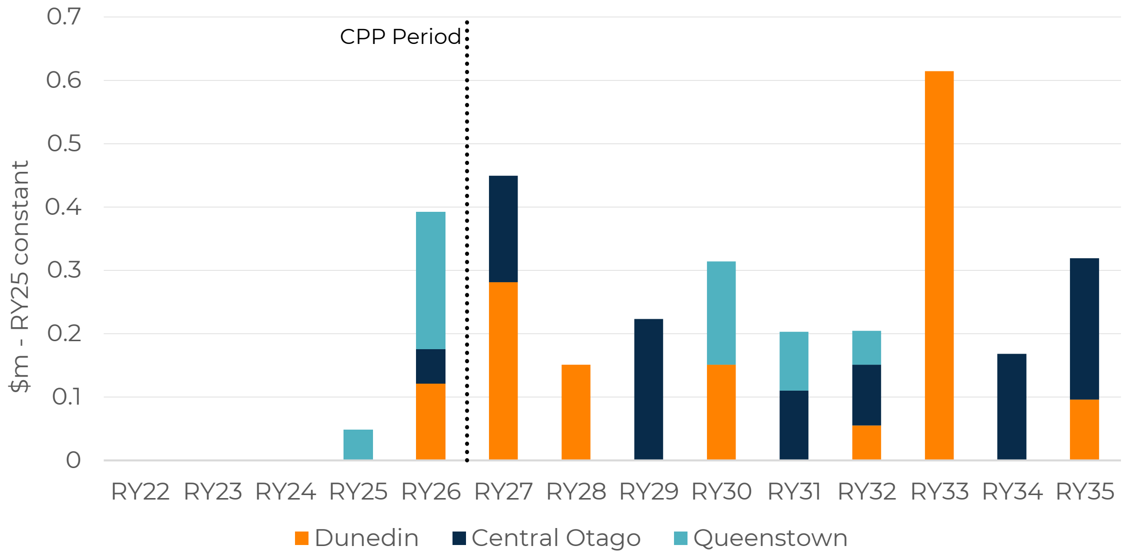
Any RTU module that can be used as a spare is retained. Disposal requirements are minor and follow the same manner of disposal as other electromechanical or electronic devices.

FORECAST CAPEX EXPENDITURE

We take a volumetric approach to RTU renewal forecasting, using unit rates for major and minor RTUs.

We have forecast approximately $3.1 million for RTU capex during this planning period. This expenditure excludes RTU systems replaced under zone substation projects.

Figure 11-63: Capex forecast remote terminal units by region (RY25 constant, $m)



11.9.2. Protection systems fleet

Protection systems rapidly detect network faults and initiate the opening of circuit breakers to isolate the fault from the rest of the network, preventing harm to people and assets. Protection systems must be able to discriminate between faults occurring on adjacent parts of the system and faults occurring on the parts they are deployed to protect, and their reliable performance is critical to the safe operation of our network.

Protection systems consist of protection relays, along with their associated cabinets, auxiliary equipment, and wiring. Our fleet encompasses protection assets inside zone substations, at GXPs, and at high voltage customer sites where an indoor switchboard is present.

We have three types of protection relay on our networks:

- **Electromechanical:** A legacy technology that converts electrical signals (such as current and voltage) into mechanical forces, which operate primary plant secondary circuits. These are simple devices with limited functionality.
- **Static:** Analogue, semiconductor-based relays that are also a legacy technology. Spares can be difficult to source and repairs are not generally economical.

- **Numerical:** An electronic device – and our preferred relay type – these units can be programmed and configured to provide a wide range of protection applications. They have less complex wiring, provide more sophisticated protection, indication and control, and allow remote management of the relays directly from our SCADA system.

A protection scheme consists of multiple fault detection functions. For example, a feeder relay may consist of an earth fault and three different overcurrent functions for different types of fault and speeds of detection.

A protection scheme is implemented using electromechanical relays will require a relay for each protection function. A protection scheme implemented with numerical protection relays will typically use a single numerical protection relay providing several protection functions.

Numerical schemes make up around 57% of our raw population of protection relays, while static and electromechanical account for 13% and 30%, respectively. Table 11-43 shows our population of protection relays by type and network.

Table 11-43: Protection asset population by type and sub-network

Relay Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Electromechanical	196	7	0	203
Static	52	27	22	101
Numerical	248	152	76	476
Total	**496**	**186**	**98**	**780**

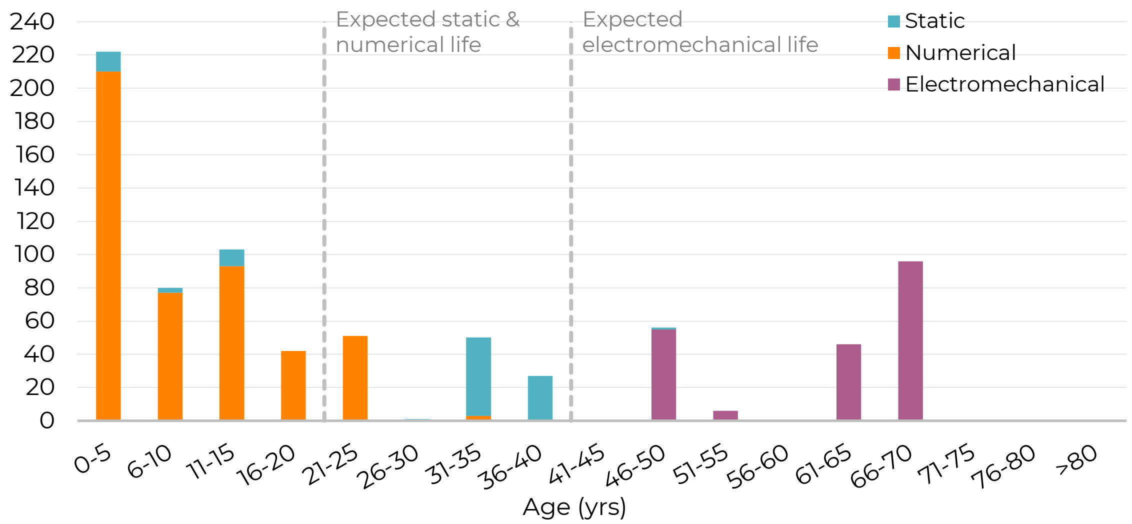
ASSET AGE

Figure 11-64 depicts the age profile of individual relays (not schemes). It shows that relays have been installed in phases, generally when substations were established or switchboards replaced.

Relay EOL is generally driven by obsolescence, lack of spares, and cost to maintain. The expected life of an electromechanical relay is 40 years, while for the numerical and static types, a 20-year life is expected.

Nearly all of our electromechanical relays have exceeded their life expectancy and spares for them can no longer be purchased. Nearly all of our static relays have also exceeded their expected life and we only have spares for some makes and models. Many numerical relays will reach their expected life during the AMP period.

Figure 11-64: Protection relay age profile



ASSET HEALTH

Overall, our relay fleet is performing well; however, there are concerns regarding certain makes and models that are resulting in a significantly deteriorating AHI for the fleet.

In particular, the reliability of ageing electromechanical and static relays is deteriorating, leading to higher maintenance costs and obsolescence due to parts scarcity.

Electromechanical and static relays are old and largely obsolete technologies with very limited spare parts and manufacturer support and very few technicians with the skills to service them. The functionality of these relays is usually limited to a single protection function, so multiple relays are required for each protection scheme. They also provide limited performance in comparison to numerical relays, which have significant additional functionality (i.e., fault recording and remote interrogation).

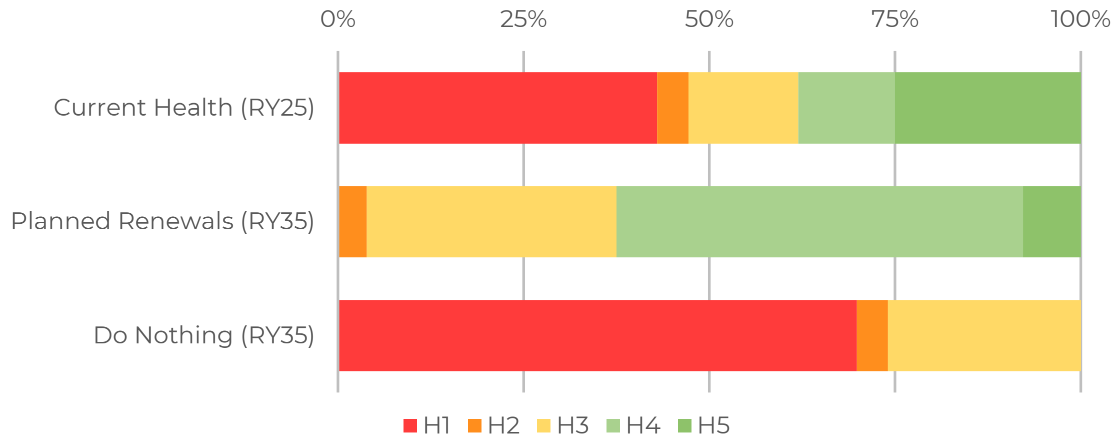
The electromechanical relays in our fleet are reported for wear-related challenges, with issues like sticky contacts and mechanisms and inconsistent timing compromising their reliability in detecting and discriminating network faults. Calibration issues in electromechanical relays and electronic drift in static relays are addressed during scheduled maintenance.

The static relays bring additional functionalities, including SCADA interfaces. However, they lack disturbance recording capabilities and manufacturer support, and their electronic components – such as capacitors – can age, leading to a higher frequency of reliability issues, particularly related to component failure.

The numerical relays, which constitute the largest portion of this fleet, are generally in good condition. They offer enhanced functionality, richer information, and improved reliability for system stability. Despite a shorter life expectancy due to their microprocessor-based technology and susceptibility to excessive heat (addressed through substation air conditioning), numerical relays typically self-report malfunctions.

Figure 11-65 shows the current and projected AHI of our protection relays, along with the expected health under a 'do nothing' scenario.

Figure 11-65: Projected protection relay asset health



ASSET PERFORMANCE AND RISK

Protection relays have evolved over time. A percentage of our protection fleet comprises legacy type relays, which provide basic protection functionality. These static and electromechanical relay types are at an age where we have concerns about their ongoing reliability and we are incurring increased maintenance costs to keep them in service.

Lack of spare parts and manufacturer support are also driving their obsolescence. We are facing a lack of technicians with the skills to service electromechanical relays, and other electricity distribution businesses are also removing them from their networks.

Table 11-44 sets out the key risks we have identified in our protection fleet and their associated mitigations.

Table 11-44: Key protection system risks and mitigations

Risk/Issue	Mitigation
Failure to detect conductor to ground	Increased preventive maintenance on electromechanical and static relays to manage calibration Replacement programme Backup protection schemes
Obsolete relay failure (whether in service or when tested) with no spares available, prolonging equipment out of service	Spares purchased where available Contingency planning to use a different model
CT open circuited resulting in equipment failure due to overvoltage (potential fire risk)	Modern relays equipped with alarming
Incorrect CT polarity, ratio, or other connection, resulting in maloperation	Preventive testing, commissioning procedures
Incorrect protection settings applied, resulting in maloperation	Controlled settings database and procedures for revising settings
Seismic event leads to maloperation of electromechanical relay and loss of supply	Replacement programme

REPLACEMENT/RENEWAL

We forecast renewal need based on our strategy of removing from service all electromechanical relays and all other relays that are obsolete or have reached EOL. We have scheduled the total annual number of renewals to match our capability to deliver in an efficient manner. This is necessary due to the large number of overdue protection relay renewals.

The main drivers for renewal of protection schemes are as follows.

- **Public and operator safety criticality:** Protection schemes are critical to the safe operation of our network, and failure of protection to clear a fault poses a significant safety risk.
- **Obsolescence:** Relays with limited or no manufacturer support. The technology employed in electromechanical and static relays is outdated and our service providers are finding it difficult to sustain the skills necessary to maintain these relays.
- **Performance:** We observe settings 'drifting' on electromechanical and static relays. During routine maintenance, relays that have drifted are recalibrated to minimise timing errors.
- **Functionality:** Modern numerical relays provide significant additional functionality that, among other things, enables us to improve management and operation of our network through easy access to detailed fault information.

Some of our existing schemes contain areas where there is inadequate protection – i.e., they do not meet our subtransmission and zone substation protection standard. Most of these will be brought up to standard when they are replaced. Some lower priority protection gaps will remain due to site constraints, and we will further investigate the appropriate timing to address these gaps following completion of our more immediate priorities.

Note that in most cases, multiple electromechanical relays can be replaced by a single modern equivalent numerical relay. When these modern relays are employed, our protection engineers are able to swiftly download and review event data and remotely modify the protection logic and settings. This results in a much better understanding of network events and significantly improves our ability to refine our protection systems and take measures to reduce safety risks and prevent consumer outages.

We replace a considerable number of protection assets as part of zone substation projects and to align with Transpower work at GXPs.

DISPOSAL

Relays with potential for use as spares are retained. Disposal requirements are minor and similar to other electromechanical or electronic devices. Some of our existing Buchholz devices contain mercury and we use appropriate disposal methods when these are replaced.

FORECAST CAPEX EXPENDITURE

We take a volumetric approach to protection renewal forecasts. Unit rates vary depending on the function of the relay, with bus zone or subtransmission protection relays having higher unit costs.

Historic levels of renewals have been low. This year we have undertaken a review of project synergies and timing with associated planned zone substation renewals and the impact of progress against the intent of the CPP determination. Although we will not meet our plan with respect to reducing the percentage of assets having an AHI of H1 on the network within the CPP period, we have put in place controls such as additional inspection and maintenance activities. Of note, despite the expected life exceedance, we are not seeing the emergence of failure trends on our network.

We have undertaken a review with respect to our fleet strategy and have set a plan that enables us to catch up on the backlog of renewals of this fleets within the DPP4 period.

We have replaced a significant number of electromechanical relays, and many of those remaining will be replaced as part of our substation renewal programme. Further, we are upgrading static and first-generation numerical relays that have reached EOL. Some protection scheme renewals will be brought forward or deferred to fit in with zone substation upgrades or renewals.

The key benefit of our planned renewal programme is mitigation of relay failure or maloperation risk. Other benefits are reduced maintenance costs, increased functionality, increased standardisation (reducing human error), and improved reliability performance.

Our CPP commitment regarding the percentage of the protection fleet having an AHI of H1 (%H1 AHI) will not be met by the end of the CPP period. We now forecast that we will reach this commitment within the DPP4 period. The delays in meeting the target fleet %H1 AHI are the result of several factors:

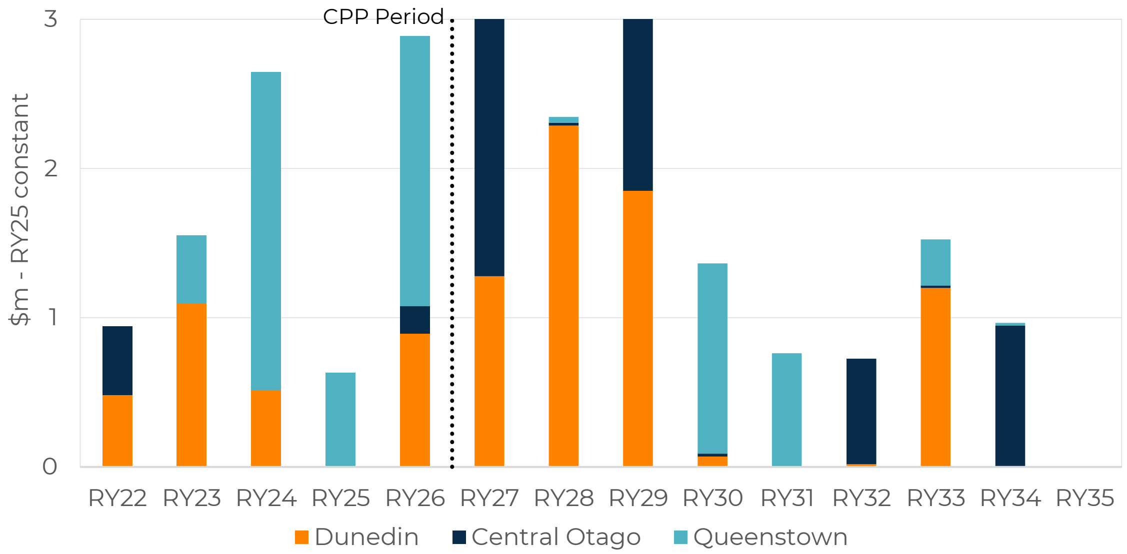
- Improved asset data, where three relays had previously been recorded as one relay in some locations
- Improved forecasting showing more relays removed than commissioned in some locations
- Rising costs of replacements leading to deferrals
- Consolidation of protection renewals with switchgear renewals for economic benefit where the risk can be managed appropriately

The result is that our %H1 AHI remains higher than previously forecast.

To manage the risk of failure for protection asset renewals that have been deferred or consolidated into switchgear renewal projects, we have increased the maintenance frequency. The sites involved have also been assessed for sufficient backup protection systems; and although these assets have already passed their planned life, the age and condition of the affected assets are key considerations when deferring asset renewal.

Our forecast protection renewal capex is approximately $17.2 million during the planning period. This expenditure excludes protection replaced under zone substation projects.

Figure 11-66: Capex forecast protection by region (RY25 constant, $m)



11.9.3. DC systems fleet

DC systems ensure a reliable and efficient power supply to vital elements within our zone substations and our assets at GXPs. Protection equipment, SCADA equipment such as RTUs, metering, communications, and security alarms are all powered by DC systems so that they can continue to operate should the AC supply be lost, such as during a fault – precisely when protection needs to operate.

DC systems consist of:

- Batteries
- DC-DC converters (designed to transform DC voltage from one level to another)
- Chargers (also known as rectifiers, as they convert AC to DC, to charge the battery)
- DC distribution panels

Our batteries are predominantly sealed lead acid and provide DC supply at voltages from 12 V to 110 V. Our high voltage batteries mainly serve protection equipment, while lower voltages are mainly used for SCADA, communications, and field recloser controllers.

DC systems at most of our substations have N−1 redundancy. Over the past few years, we've made substantial investments in upgrading numerous DC supply systems to adhere to our established DC standards.

Our existing DC supply systems predominantly employ up-to-date technology and deliver satisfactory service levels, but a few are awaiting upgrades to align with upcoming zone substation renewals over the next few years. The majority of our indoor battery banks operate in temperature-controlled environments, with the exception of outdoor substations and field reclosers, where significant temperature fluctuations can reduce battery life.

The majority of zone substations utilise DC-DC converters to supply power to communication equipment. However, a few have dedicated 24/48 VDC supplies specifically allocated for communication purposes. This includes sites exclusively designated for communication. Table 11-45 and Table 11-46 summarise our population of DC systems.

Table 11-45: Battery bank asset population by voltage and sub-network

Voltage level	Dunedin	Central Otago & Wānaka	Queenstown	Total
110 V	32	18	8	58
48 V	4	5	3	12
12/24 V	9	42	22	73
Total	**45**	**65**	**33**	**143**

Table 11-46: Rectifier and converter asset population by voltage and sub-network

Voltage level	Dunedin	Central Otago & Wānaka	Queenstown	Total
110 V	33	16	10	59
48 V	7	8	3	18
12/24 V	48	45	18	111
Total	**88**	**69**	**31**	**188**

ASSET AGE

Figure 11-67 and Figure 11-68 give the age profiles of our DC systems. The majority of our battery banks are younger than their expected life of 8 to 10 years, while the remainder are awaiting planned zone substation projects.

Field recloser batteries are renewed on a more frequent four-year cycle during regular inspections, due to their small capacity and the temperature fluctuations they experience in their outdoor boxes.

Figure 11-67: Battery bank age profile

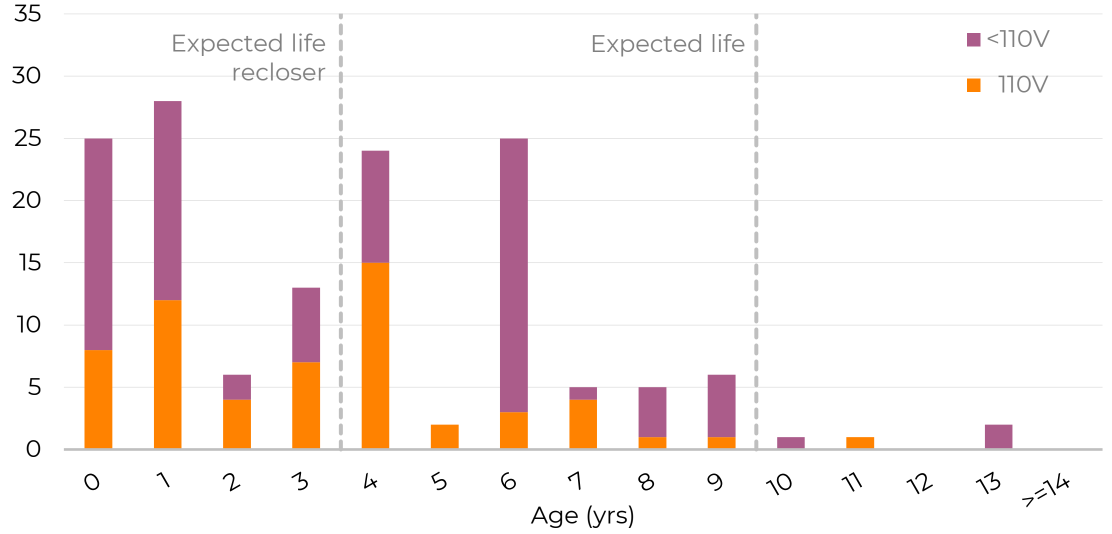
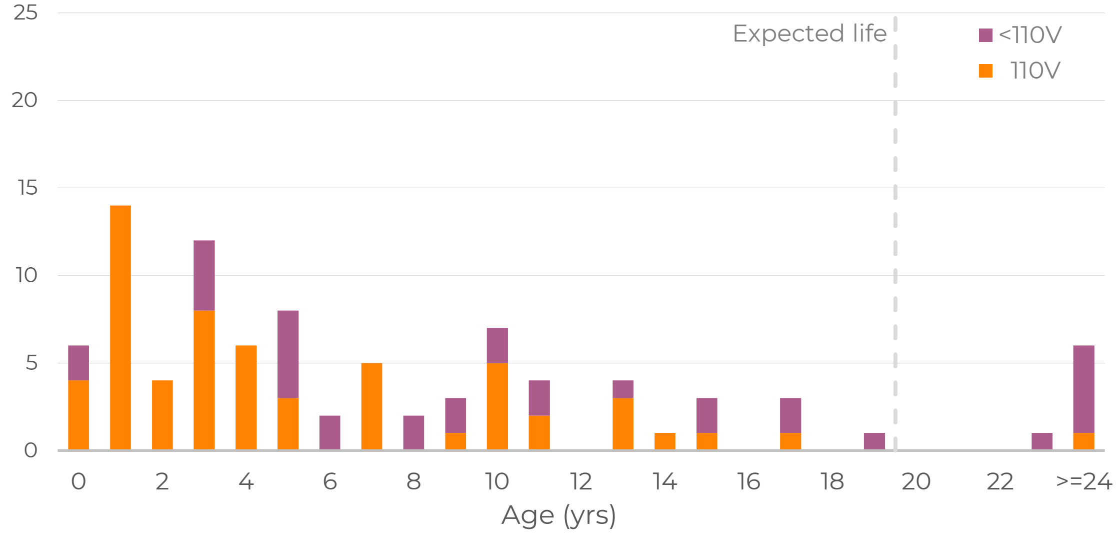


Figure 11-68: Rectifier & converter age profile



ASSET HEALTH

The condition of our DC systems is generally acceptable, based on the age profile against good industry practice life expectancies. Few of our batteries are exposed to large temperature variations due to their locations, which has a significant impact on their condition and life expectancy. Batteries are replaced into temperature-controlled environments where possible; however, this may not occur until a project occurs at the site to provide a suitable location. A sizable part of our battery fleet supplies field reclosers and lacks temperature control. These small outdoor batteries are renewed on a more frequent cycle of four years.

Figure 11-69: Predicted battery asset health profile

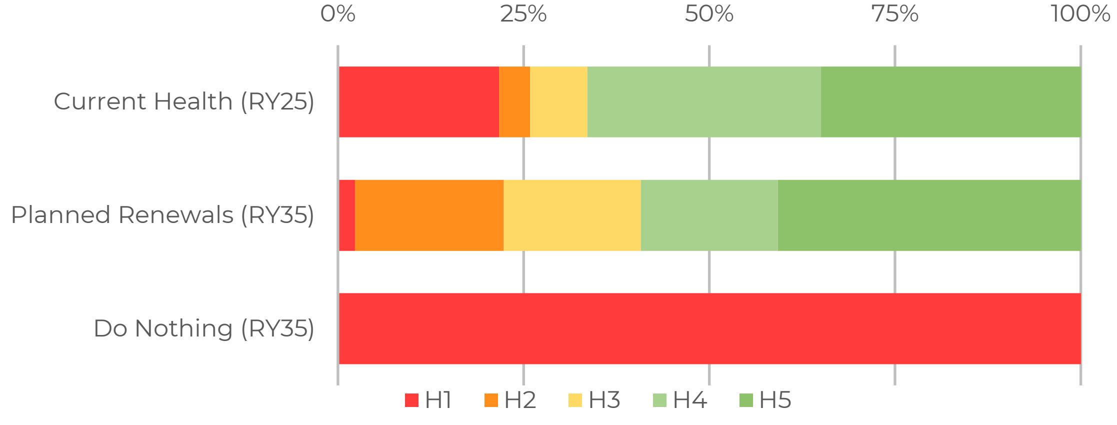
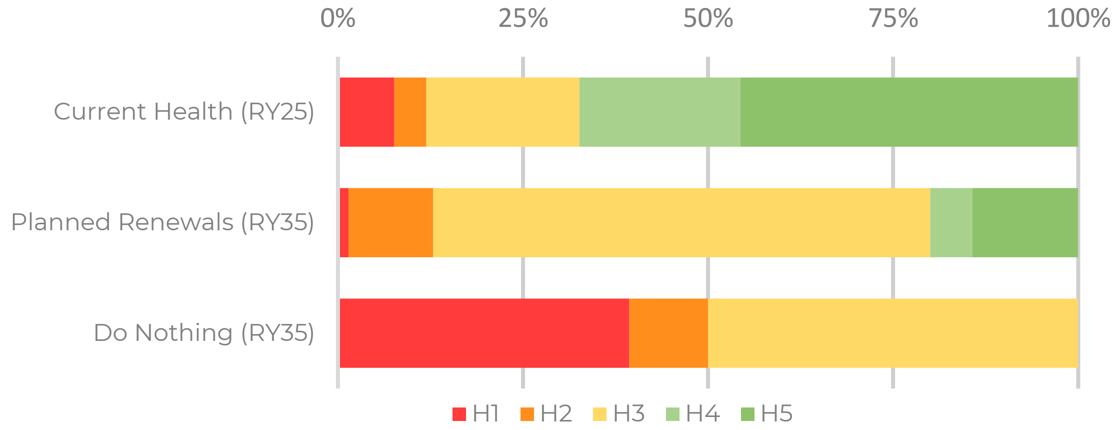


Figure 11-70: Predicted rectifier & converter asset health profile



ASSET PERFORMANCE AND RISK

Table 11-47 sets out the key risks identified in relation to our DC systems and their associated mitigations.

Table 11-47: Key DC system risks and mitigations

Risk/issue	Mitigation
DC system fails in service, leading to protection maloperation, no visibility, or no network control	Inspection and test regime for alarms and monitoring Age-based replacement N−1 battery systems installed where applicable/possible
Catastrophic battery failure (i.e., thermal runaway) leading to fire	Alarms and monitoring

REPLACEMENT/RENEWAL

Generally, we aim to replace batteries once they reach eight to ten years of age; otherwise, they are replaced based on condition. Some DC supplies will be replaced or upgraded to our DC standard as part of our zone substation projects.

Key drivers of expenditure for renewal of DC systems are:

- **Condition:** If a battery bank fails discharge testing, we replace the faulty batteries within the bank. If a charger is tested and found to be faulty, it is replaced.
- **Age:** Batteries have an expected life of eight to ten years (depending on system redundancy and the environment in which they are installed), and we replace them at this timing in line with good industry practice, or earlier if their condition dictates. Chargers and DC-DC converters are replaced when they reach their expected life of 20 years if they are our standard type. If not, they are replaced with the first battery bank replacement.

In our DC standard we have adopted the good industry practice of duplicating DC systems where possible. In the case of batteries other than the main protection battery bank or subject to space constraints, we undertake like-for-like replacements.

In the longer term, we may consider staggering replacements at N−1 battery bank sites. Given the redundancy at such sites and assuming batteries still pass test results, this approach may help smooth the expenditure profile and corresponding workload while maintaining an acceptable risk level.

We undertake battery replacements in conjunction with zone substation renewal or protection upgrades where possible. However, given the importance of our DC systems, any such asset that has exceeded its expected life must be replaced as soon as possible, rather than waiting for future project consolidation.

DISPOSAL

Lead acid batteries are recycled at end-of-life. Chargers are disposed of in the same manner as other electronic equipment.

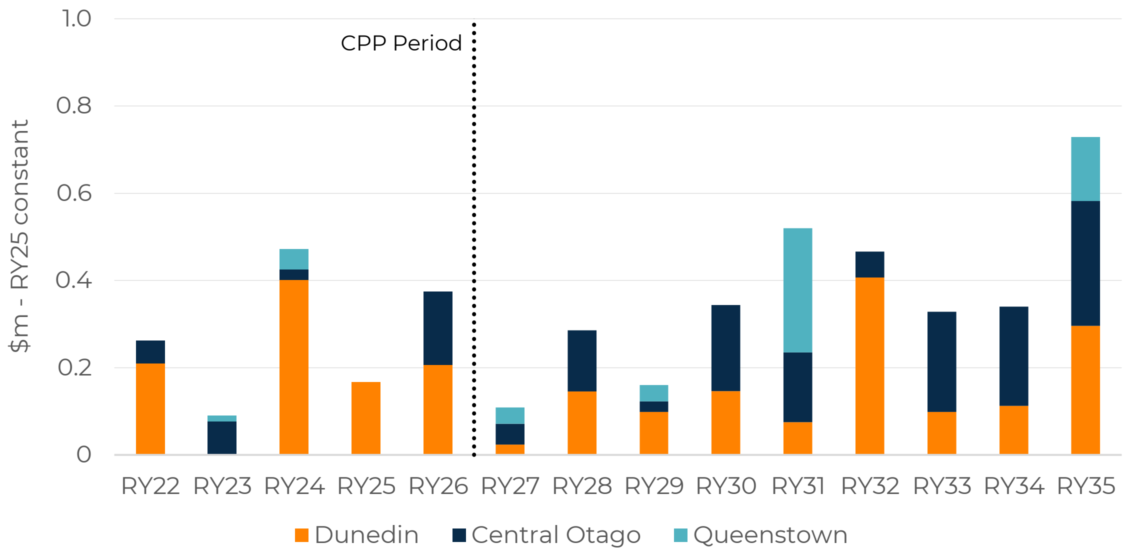
FORECAST CAPEX EXPENDITURE

We take a volumetric approach to DC systems renewal forecasting. We use unit rates for different voltage battery banks, chargers, and distribution panels.

Capex was low prior to RY20, mainly because work was bundled or classified as zone substation renewals. However, as a large number of batteries already meet our criteria for renewal, a standalone renewal programme is required. We plan to increase renewals to supplement the zone substation renewal-based DC works, as shown in Figure 11-71.

We have forecast battery and DC systems capex of approximately $3.6 million during the planning period. This expenditure excludes DC systems replaced under zone substation projects.

Figure 11-71: Capex forecast DC systems by region (RY25 constant, $,000s)



11.9.4. Metering fleet

Our metering fleet includes check metering at GXPs and power quality units at some zone substations. Check meters are installed at our GXPs to confirm and authenticate the accuracy of the Transpower revenue meter. They also serve as a quality control measure, independently ensuring the precision of the Transpower revenue meter, as well as functioning as a backup in instances where Transpower meters are out of service.

We have replaced older and unsupported meters at three of our GXPs, but we still have legacy check meters in the Central Otago sub-network. Modern GXP check meters can communicate via a modern protocol (i.e., DNP3) and provide remote access functionality. Our meters can record additional parameters, such as peak and average MVA and power factor.

We have installed 15 power quality meters on the 11 kV or 6.6 kV incomers of our modern zone substations. These meters monitor key power quality parameters to detect potential issues related to increased distributed generation and harmonic-emitting electronic devices. Providing remote engineering access and DNP3 communication capabilities, the high precision and accuracy of these meters enable our planning team to make informed decisions based on reliable data. The output parameters from power quality meters are also monitored via our SCADA system and are configured to alarm our control room if the measured values exceed specific thresholds.

ASSET AGE

Table 11-48 shows the population of our metering assets by type and sub-network.

Of the 11 check meters across our network, all but two are currently 10 years old or less, while two are near EOL. One of our EOL meters is to be replaced in RY25, while the other is scheduled to be replaced in RY26.

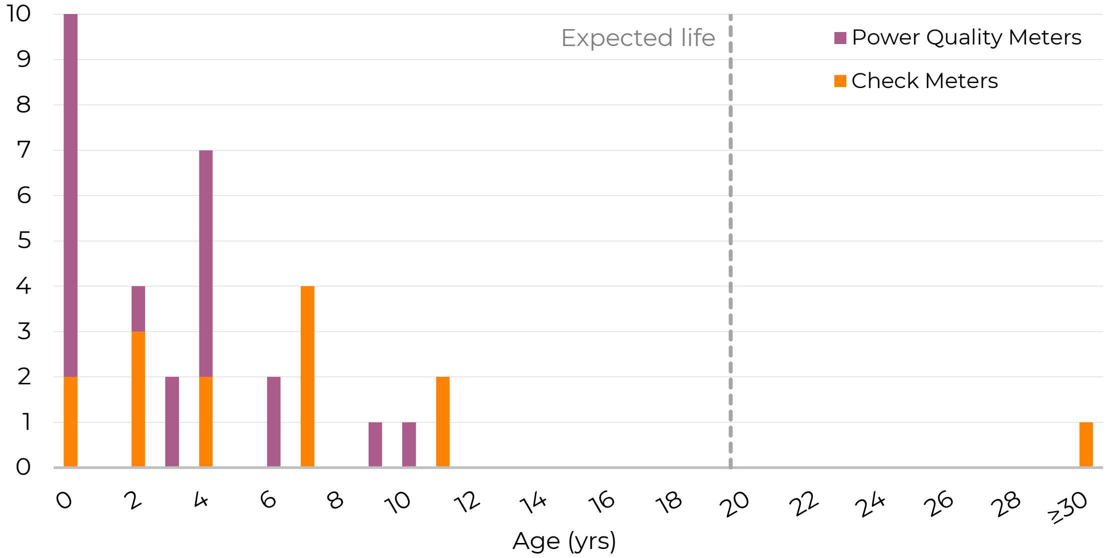
Our power quality meters are all less than eight years old.

The life expectancy of a modern numerical meter is 20 years.

Table 11-48: Metering asset population by type and sub-network

Meter Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Check Meter	6	3	2	11
Power Quality Meter	15	5	4	24
Total	**21**	**8**	**6**	**35**

Figure 11-72: Metering age profile

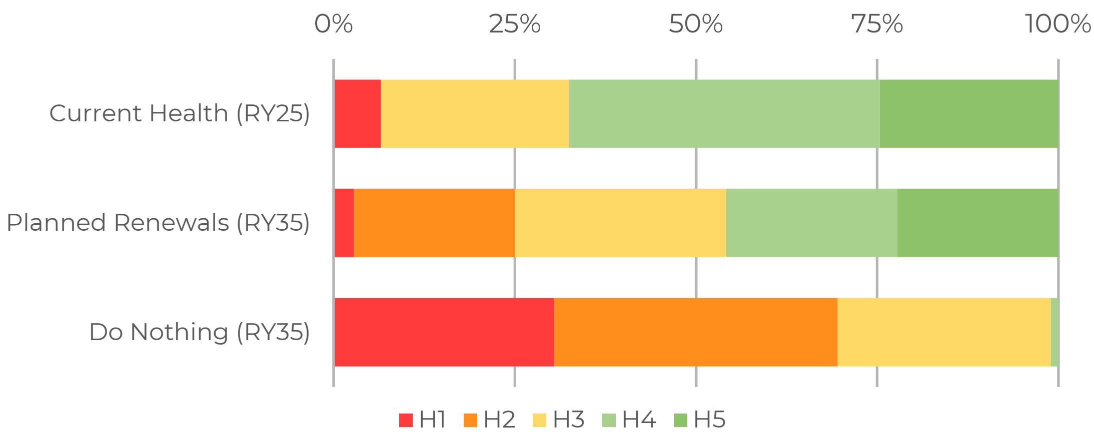


CONDITION AND HEALTH

We are not experiencing any condition or performance issues with our metering fleet.

Figure 11-73 depicts the current fleet health alongside the forecast health and the counterfactual 'do nothing' scenario.

Figure 11-73: Predicted metering asset health profile



ASSET PERFORMANCE AND RISK

Table 11-49 sets out the key risks identified in relation to our metering fleet and their associated mitigations.

Table 11-49: Key metering system risks and mitigations

Risk/issue	Mitigation
GXP revenue metering failure	Reconciliation of data Transpower metering calibrations
Loss of load control	Load control system uses our and Transpower's revenue metering, together with SCADA MW measurements, so has redundant inputs

REPLACEMENT/RENEWAL

Renewal of meters is usually undertaken in conjunction with other work such as GXP and protection upgrades.

DISPOSAL

Disposal requirements are minor, similar to those for other electromechanical or electronic devices.

FORECAST CAPEX EXPENDITURE

We take a volumetric approach to renewal forecasting for metering systems and use unit rates for power quality meters and check meters.

We have forecast metering capex of approximately $0.3 million on check metering during the planning period. This expenditure excludes metering systems replaced under zone substation projects, and also excludes power quality meters that are bundled with protection renewals at zone substations.

11.9.5. Communication assets fleet

Resilient and reliable communications are critical to ensuring the efficient operation of the modern power grid. Control and monitoring systems are installed throughout the power grid to ensure the efficient delivery of power, and these systems are dependent on the connectivity provided by the communication networks and systems.

Aurora Energy's communications assets for SCADA, teleprotection, ripple communications, and other operational services can be divided into communications cables (comprising copper and fibre optic cables) and communications systems (comprising radio networks and a wide area network [WAN] IP network).

Communications cables consist of paired copper pilot cables and fibre optic cables. Most of the paired copper and optical fibre cables are in the Dunedin service area and are predominantly underground cables, with some short overhead sections running between substations. The cables terminate in panels inside the substation buildings, but jointing locations do exist in various fibre pits around the Dunedin service area.

Pilot cables were originally installed for protection and alarms during the installation of the 33 kV subtransmission systems, well before a SCADA system was introduced. The pilot cables are a combination of 19AWG copper twisted and untwisted pairs in bundles. We have already decommissioned more than half of the original installed base of copper pilots and are migrating services over to newer optical fibre cables as they become available.

Our radio networks comprise licensed IP-based point-to-multipoint UHF radio networks and broadband microwave radio links. Aurora Energy has also deployed TDM point-to-point radios, an older technology that we specifically use to provision teleprotection services, but which also carry SCADA and other site communications. In addition, we make extensive use of public 4G networks for remote connectivity and SCADA redundancy.

All Aurora Energy sites are connected and operate over a private WAN with industrial IP routers deployed to all GXP TOAs, HV substations, and radio sites. This WAN provides secure connectivity between RTUs in the field and the SCADA master station software in the Aurora Energy data centres, thereby creating connectivity between the Control Centre and the RTUs in the field.

Many of the communication system components are IP-capable and can be remotely monitored. As with most modern electronic communications equipment, the components in this asset fleet have a much shorter life cycle than other electrical utility assets.

Table 11-50: Communications component populations by type

Asset	Terminals
UHF point to multipoint and 4G routers	115
Broadband IP microwave radio links	24
TDM UHF and microwave radio links	24
Network routers/switches	88

Table 11-51: Communications pilot cable lengths by type

Asset	Km
Copper pilot cable	35
Optical fibre cable	55

ASSET AGE

The oldest copper pilots still in service were installed around 75 years ago and the most recent pilot cables were installed approximately 20 years ago. Most of the fibre optic cables currently in service are relatively new and were installed after 2008.

Aurora Energy's entire communications system fleet is less than nine years old. This is because the entire Aurora Energy private radio network was replaced and significantly enlarged between 2016 and 2019. At this time, radio sites were established for a new microwave radio backbone network, as well as new UHF point-to-multipoint SCADA radio networks. New TDM-based digital radio links were deployed specifically for current differential teleprotection.

Aurora Energy also deployed a new operational IP WAN router/switch network from 2016 onwards, thereby creating a private SCADA IP WAN.

ASSET HEALTH

Despite the advanced age of the copper cables, recent inspections show they are still functionally in good condition. However, an increase in cable attenuation (losses) on some cables has been noted, most likely due to corrosion caused by moisture ingress. In general, Aurora Energy's fibre optic cables are still relatively new and are not exhibiting any health issues.

The Aurora Energy telecommunication systems, with the exception of copper pilots, are still relatively new.

Our communication systems are less than eight years old and have been regularly inspected and maintained, so overall systems are in good condition and are performing well.

All our radio equipment is subject to annual preventive maintenance inspections and our router/switch network is actively remotely monitored to pre-empt any issues.

It has been identified that some of our older IP routers are no longer fit for purpose, and these are being actively replaced over the next three to four years.

ASSET PERFORMANCE AND RISK

In general, the copper cable network is performing well, with the only identified issues being increases in attenuation/losses. There is a risk that the cables may degrade to the point of a failure that could result in the loss of a protection function; however this is mitigated by having independent protection schemes on subtransmission circuits.

The performance of the fibre optic network has been very good and no risks have been identified.

In general, the radio and IP router network is performing well and no significant risks with regard to the assets have been identified. The routers that are being actively replaced are not a significant risk at this stage, due to network redundancy.

REPLACEMENT/RENEWAL

Our approach to the renewal of cables is mostly reactive. We decommission copper cables when they are no longer required, as services are moved to fibre optic cables.

Electronic equipment has a relatively short life and equipment replacement is typically governed by advancements in functionality together with business communication requirements – for example, the move from serial to IP for cybersecurity requirements. However, since the Aurora Energy communications network is already IP-based and the business communication requirements are relatively static, our renewal programmes are mostly based on a combination of age and availability of spares and support.

Starting in RY26, a few microwave radio links that are affected by a supplier notification of end of support will be replaced.

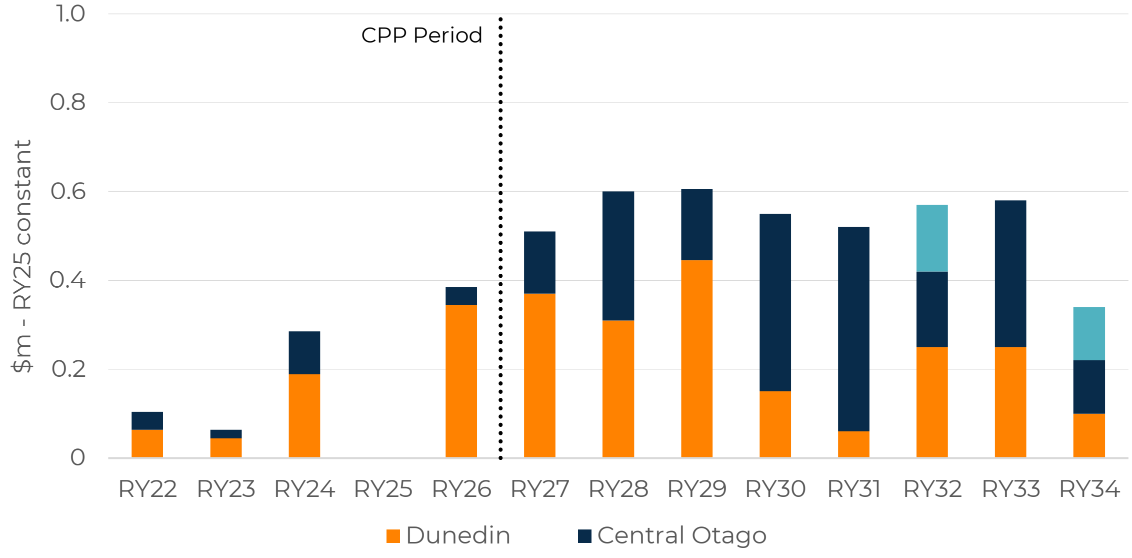
DISPOSAL

As most of our cables are underground, when they are decommissioned they are typically disconnected at the termination points and left in place. Where overhead cables are decommissioned, they are removed and disposed of using appropriate methods.

Communication equipment with potential for use as spares is retained. Any other equipment is disposed of appropriately after the memory and any other sensitive information is cleared.

FORECAST CAPEX EXPENDITURE

Figure 11-74: Capex forecast communications by region (RY25 constant, $,000s)



11.10. CRITICAL SPARES

To help with maintenance activities, we hold critical spares of certain assets. Typically, these are assets that have a long lead time, have specific characteristics, or are related to critical parts or functions of the network. We are currently developing a spares strategy wherein the need for critical spares is informed by a detailed analysis that forms part of each fleet strategy.

In addition to critical spares, we hold stocks of assets that are regularly used on the network. This includes distribution transformers of various standard sizes, our standard conductor and cable sizes, and consumables such as fuses. Our field service providers are required to manage these stores to ensure they can undertake the corrective maintenance, reactive maintenance, and replacement activities required to maintain network performance.

We have recently developed a resiliency and spares strategy for power transformers to ensure that in the event of a failure, the impact is minimised and a replacement is mobilised within a month.

Some of the considerations in establishing our objectives for transformer resiliency and developing the spares strategy were:

- The impact of transformer failure and the risk posed
- Contingency plans in place and residual risk
- The current health of transformers and renewal plans; and planned renewals expected to improve asset health and reduce the likelihood of failure and risk
- Growth plans. In some cases, growth-driven renewals will release transformers still in good health and useful as spares for other sites.
- Substation standardisation. We have reviewed current practices and designs and determined that going forward, the smallest transformer size for a zone substation will be 10 MVA. All new substations will follow a standard general design, with transformer pads adequate to support larger size transformers for any future growth.
- Site-specific constraints
- Voltage and bushing termination configurations

The objective for the resiliency and spares strategy is to ensure that every N-security zone substation is compliant with security of supply guidelines and that there will be a suitable spare transformer available for all N-security zone substations and for N-1 security zone substations without full backup capacity, throughout the distribution network.

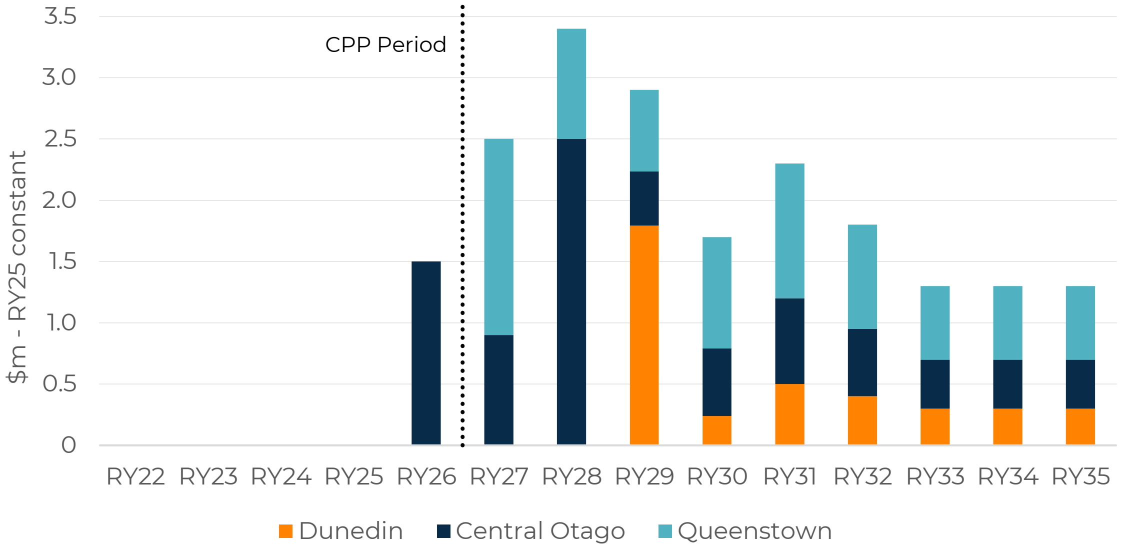
As a result, we will be investing $5m over the next three years to secure spare transformers, as follows:

- RY26–27: 66–33/11 kV, 10 MVA transformer $2.4m
- RY27–28: 33/11–6.6 kV, 24 MVA transformer $2.5m

We will also be investing $4m to establish storage facilities and $11.1m for critical spares in Dunedin, Queenstown, and Central Otago over the planning period.

Figure 11-75 shows forecast expenditure to acquire critical spares and establish spares storage facilities over the planning period.

Figure 11-75: Capex forecast resiliency by region (RY25 constant, $m)

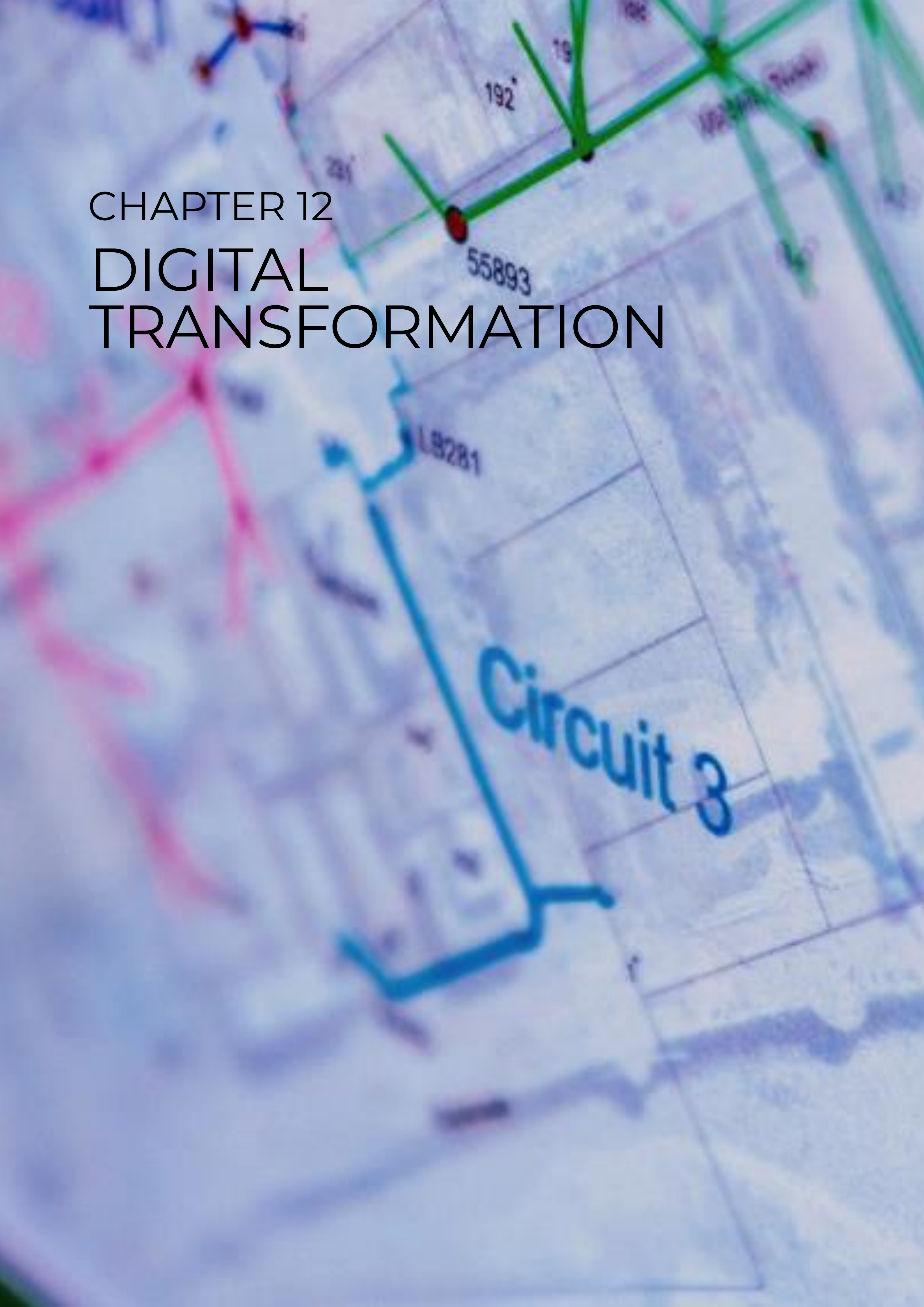


E

NON-NETWORK SUPPORT

CHAPTER 12

DIGITAL TRANSFORMATION



Our non-network support systems help Aurora Energy teams to do our day-to-day activities in an efficient manner.

12.1. AURORA'S DIGITAL TRANSFORMATION JOURNEY

Aurora Energy has prioritised rationalising the multitude of applications currently within the technology landscape, using increasing levels of software as a service (SaaS) solutions alongside on-premises solutions to ensure a sustainable, secure technology foundation during the CPP period.

Once rationalised, our information and communication technology (ICT) platform will let us provide the flexibility needed to enable the future energy choices for consumers. Our digital business transformation strategy helps us streamline priority processes, manage our assets predictively, and deliver capital works effectively.

The transformation has four elements:

- **Digitising core enterprise processes:** Reducing low value tasks, driving improved productivity, enhancing decision-making and insights, and delivering enhanced value to consumers.
- **Optimising network configuration and operations:** Optimising the use of the electricity distribution network and the distributed energy resources hosted on it.
- **Enhanced business analytics/insights and people empowerment**: Augmenting the skills and capabilities of our people and driving data-informed decision-making, and extending AI-powered analytics to our consumers and business partners.
- **Critical digital technology enablers:** So that technology supports a digital way of working at Aurora Energy and data and information are trusted, secure, and accessible.

We will progressively deploy these capabilities across the business through DPP4 and beyond, prioritising implementation by consumer benefit. Initially, we have identified five areas of focus for digital transformation – all of which support the efficient delivery of the services our consumers want.

Table 12-1: Benefits of Digital Transformation

Benefits	Business area	Initiatives
Reduce business costs through automation	Automation of maintenance and capital workflows	• Understanding asset condition in (near) real time to predict and reduce or prevent asset failure and optimise life expectancy of assets • Investigating the use of drone/HD imaging/thermographics to detect asset deterioration invisible to the human eye or standard maintenance routines
Automate tedious or dangerous work	Advanced analytics	• Using AI to process large data sets to identify emerging trends or constraints (e.g. power flow modelling, identifying fault hotspots, etc.) • Using technology to transmit asset information in dangerous (at height, confined), hard to reach, or remote locations (e.g. radio transmitters affected by snow or ice, line sag, pole shift variances, etc.)
Make sense of vast amounts of data	Smart meters and IoT	• Using smart meter data for early visibility of real-time consumer supply and voltage quality to enable faster response times and better data to triage issues on the network • Using AI to identify and monitor EV and PV uptake in the network • Using data feeds to enable real-time operational control capabilities and proactively response to load and demand forecasting
Optimise business practices	Resource and capability	• Using real-time AI processing to manage cyber threats by analysing large volumes of logs to detect and block indicators of compromise • Increasing capability across the business in the development and use of AI
Automate routine, dangerous, or repetitive tasks	Digital consumer experience strategy	• Using sensors on distribution transformers to understand and trouble shoot voltage quality issues before they become problematic • Investigating the use of robotics to respond to (online) consumer service queries

12.1.1. ICT assets and service plans

This section outlines how we manage our ICT assets and services. Each portfolio plan details the strategic direction, lifecycle needs, and forecast expenditure for the current CPP period and DPP4.

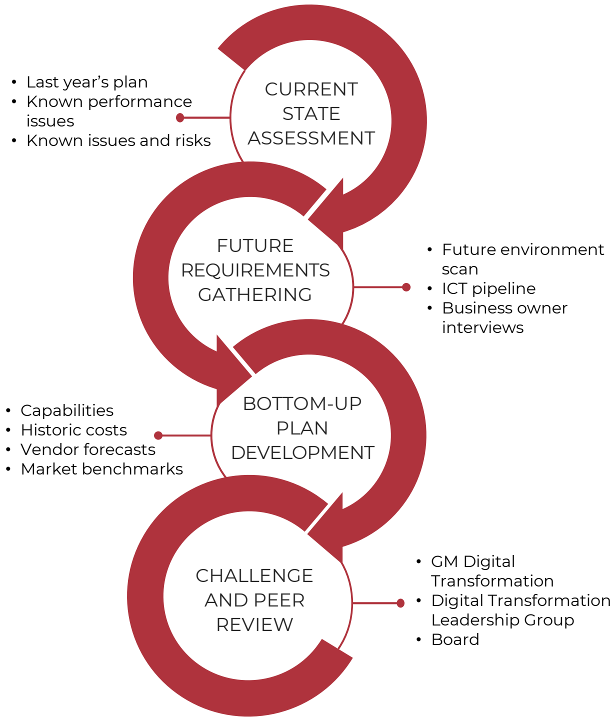
Our philosophy is to invest in ICT assets to achieve business outcomes, replacing them only at end-of-life, failure, or obsolescence. We continuously monitor ICT systems for performance and capacity, reporting monthly on key metrics such as availability, service outages, and service level achievements.

As prosumers increase and network usage becomes more dynamic, we are enhancing our capabilities, data, and insights for the business, consumers, and partners. To stay innovative, we also monitor other EDBs and emerging technologies.

Our ICT pipeline process captures new business requirements and outlines their assessment and planning.

We are confident that this process results in an evidence-based plan that is prioritised against consumer needs and benefits and is efficiently costed.

Figure 12-1: ICT requirements capture, assessment and planning process



12.1.2. Our ICT portfolios and priorities for the next 10 years

We manage our ICT assets and services across five line-of-business portfolios, as shown in Table 12-2.

Table 12-2: ICT asset portfolios

Portfolio	Description
1 Asset Management	• Supports the creation, management, and operation of assets and asset management lifecycle • Supports the forecasting and planning of distribution asset maintenance and our data collection systems
2 Operational Technology	• Includes distribution management and associated SCADA, OMS, and Historian systems to support the core distribution services and management of substations through the provision of real-time and time-series information
3 Consumer & Commercial	• Systems and technology used to support consumer care and management, billing, regulatory compliance, and commercial activities
4 Corporate	• Systems used to support our corporate operations through human resource, finance, risk, audit, and compliance, legal and property services
5 Enterprise Technology & Infrastructure	• Supports ICT services and infrastructure (servers, operating systems, data centres, storage, backup), identity and access management, telecommunications, network, security, end-user devices, and business continuity and disaster recovery capability

ICT solutions evolve rapidly as more devices and processes rely on digital technologies. Most of our capitalised ICT assets depreciate in less than five years, highlighting the fast pace of innovation in the industry.

ASSET MANAGEMENT

Asset management services support core activities like asset inspections, work planning, job management, and long-term asset management strategies. During the CPP period, our focus has been on commissioning new tools for job management and enhancing asset data collection through field mobility with partners. This improves our risk and condition assessments and our asset management maturity and enables efficient selection and implementation of work and job management tools. Ultimately, this enhances our ability to plan maintenance and replacements efficiently to meet consumer needs.

We are on track to commission this core capability by the end of the CPP period, which will enable us to deploy advanced analytics to improve the efficiency with which we plan, manage and work on our field assets.

Table 12-3: Asset Management investment focus

Horizon	Investment focus
CPP	• Ongoing implementation of our new asset management software solution to consolidate data through systems integration and field mobility and to support capital and operations work planning and delivery • Completing development of an automated process to create and refresh our network power flow model • Further enhancing our asset inspection applications to better inform asset condition data and asset management decision-making
DPP4	• Extending our asset management software solution to embed or integrate with advanced analytics capability, to support condition-based risk assessment and use of near real-time asset health indicators • Upgrading our geospatial solution and integrating it with our operating system to allow near real time updates from the field • Continuing integration with other core systems and embedding and supporting the development of new capability such as low voltage network modelling incorporating smart meter data and other third-party information • Adding/improving capability to support external data sets • Increasing work process automation • Potentially undertaking a lifecycle replacement of one or more parts of the systems used: GIS, asset management, analytics toolsets

OPERATIONAL TECHNOLOGY

Operational technologies are the real-time tools that we use to run our network. The core tool is our Advanced Distribution Management System (ADMS), which comprises three core elements: SCADA, OMS, and Historian.

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

SCADA allows us to monitor and manage the distribution network in real time. We upgrade and update this application as required to deliver new functionality required to manage the system efficiently.

OUTAGE MANAGEMENT SYSTEM (OMS)

By modelling the topology of the network and integrating with our other consumer management tools, the OMS enables us to plan and communicate outage restorations predictably, efficiently, and safely. As a component of our operational technology, this system is critical to the safe and reliable management of outages throughout the network and must achieve exceptionally high reliability for regulatory and consumer purposes.

HISTORIAN

Historian is a time series data repository that enables detailed analysis and investigation of network performance, operational trends, and incidents.

During the CPP period, our efforts have been focused on upgrading SCADA and completing the implementation of an OMS. This work has enabled better management and communication of all outage incidents on the network, managing outages more efficiently and providing up-to-date information to consumers by feeding data directly to the website and call centre.

In DPP4, these foundations will be used to progress our network understanding and make provision for distributed energy resources, including bidirectional and dynamic power flows. Future SCADA upgrades and additional solutions enabling increased flexibility management will give network controllers improved visibility and the ability to manage devices at the edge of the network, ensuring that power quality and reliability are maintained for all consumers.

The OMS will automate the restoration of supply after unplanned outages, allowing faster power restoration and providing consumers with more accurate notifications about outage durations. The operational management of the low voltage (LV) network necessitates further investment in SCADA systems and the introduction of a scalable flexibility management system, which is most likely to be a SaaS solution.

This will enable understanding and near real-time management of low voltage power flows to address load constraints and accommodate the increasing presence of electric vehicles (EV) and photovoltaic (PV) systems within these networks. There are a number of associated dependencies with advancing the management of the LV network, including upgrading the electricity model in GIS and integrating that to SCADA to make visible the LV assets and their electrical power flows.

Table 12-4: Operational technology investment focus

Horizon	Investment focus
CPP	• Upgrading the capability of our ADMS – particularly its Outage Management module – to fully supported versions that allow improved cyber security and external support, for improved management, consumer communication, and reporting of planned and unplanned outages on the network • Review of the digital mobile radio operational voice network lease
DPP4	• Extending distribution management capability further into the LV network • Implementation of real-time distribution power flow into our ADMS • Increasing capability for management of flexibility traders and large-scale distributed energy resources • Improving consumer case management and consumer services • Potentially moving parts of these technologies to SaaS solutions – which may drive a major lifecycle replacement

CONSUMER AND COMMERCIAL

Our portfolio includes billing, case management, and regulatory compliance services. During the CPP period, we have focused on making our billing and pricing solution future-ready and exploring enhanced customer relationship options.

In RY25 we added a risk management solution to our technology stack, allowing us to improve the reporting, monitoring of our enterprise risks and their associated critical risk controls.

Building on this, in DPP4 we plan to develop new capabilities to support consumers as they increase their use of distributed energy resources, while controlling the cost of doing so.

Table 12-5: Consumer & Commercial investment focus

Horizon	Investment focus
CPP	• Maintaining billing systems, planning increased consumer care and service capability
DPP4	• Improving consumer case management and consumer services • Increasing distributed systems capability • Raising our ability to deploy new pricing methodologies for consumers • Improving operational efficiency

CORPORATE

Our corporate services cover all non-network or consumer-related activities including finance, HR, risk management, legal, and property. Our current financial management and HR technology services are relatively mature.

Our main focus during the CPP period has been on consolidating our legacy financial management system as it nears the end of vendor support and exploring upgrade or replacement options for that finance/payroll system. In DPP4, we will prioritize migrating to the most efficient solution or solutions that will meet our future needs, including considering software as a service solutions.

Table 12-6: Corporate investment focus

Horizon	Investment focus
CPP	• Implementing a business system integration platform to enable systems to support end-to-end business processes and ensure one source of data • Completing separation of Aurora Energy infrastructure and services from Delta • Optimising our communications network by improving redundancy and ensuring a higher level of resilience
DPP4	• Reviewing and upgrading or replacing core financial systems and payroll systems • Reviewing and upgrading or replacing billing system and future customer relationship management (CRM) requirements • Enhancing new financial tools

ENTERPRISE TECHNOLOGY & INFRASTRUCTURE

This covers the enabling technology and generic technology frameworks and platforms that enable us to provide mobile access to business services, integrate standalone data sources, and analyse information. This technology also allows us to support the processing, storage, and exchange of digital information around the company.

During the CPP period we have completed the overhaul of our voice and digital communications to support operational technologies. Through DPP4 we will explore opportunities to continue to standardise infrastructure and deploy enterprise capabilities and leverage advanced analytics, supported by artificial intelligence and machine learning, across the business.

Table 12-7: Enterprise Technology & Infrastructure investment focus

Horizon	Investment focus
CPP	• Continued support of existing systems while improving operational efficiency • Data preparation and support for the development of business information dashboards
DPP4	• Standardising our communications network • Exploring opportunities for sensors, machine learning, and use of AI to drive enhanced analytics

12.2. EXPENDITURE OVERVIEW

Consistent with inflationary pressures in the wider economy, current actual costs continue to exceed our CPP allowances. For example:

- **Labour:** Market salaries for ICT staff in Dunedin and Cromwell have increased at a faster rate than inherent within the CPP Determination.
- **Licensing:** Our two largest suppliers, Microsoft and SAP, and their support partners, have increased their annual licence and support fees by more than 5% in 2024.

We have also had to implement new and enhanced ICT capability that we did not anticipate at the time of preparing our CPP application:

- **Cyber security:** As a lifeline utility, Aurora has been and continues to be exposed to more and more varied threats and attacks by malicious actors, all of which could threaten our ability to conduct our core business operations and provide network services to our consumers. Throughout the CPP period, cyber costs have increased from levels envisaged prior to making the CPP application. We expect these costs to continue to increase throughout the DPP4 period beyond levels currently being incurred, consistent with global security trends targeting critical infrastructure.
- **LV visibility:** Our consumers are replacing fossil fuels with renewable electricity as a core strategy for decarbonisation. We have seen and are anticipating exponential increases in new electrical appliances (particularly EVs) and embedded (particularly solar) generation and battery storage. This trend of ‘prosumerism’ requires us to monitor and manage our LV networks more actively and dynamically than we have ever had to in the past. We have recently agreed commercial terms for the procurement, storage, management and analysis of LV meter data to help us do

this. The associated operational costs are included in our forecasts.

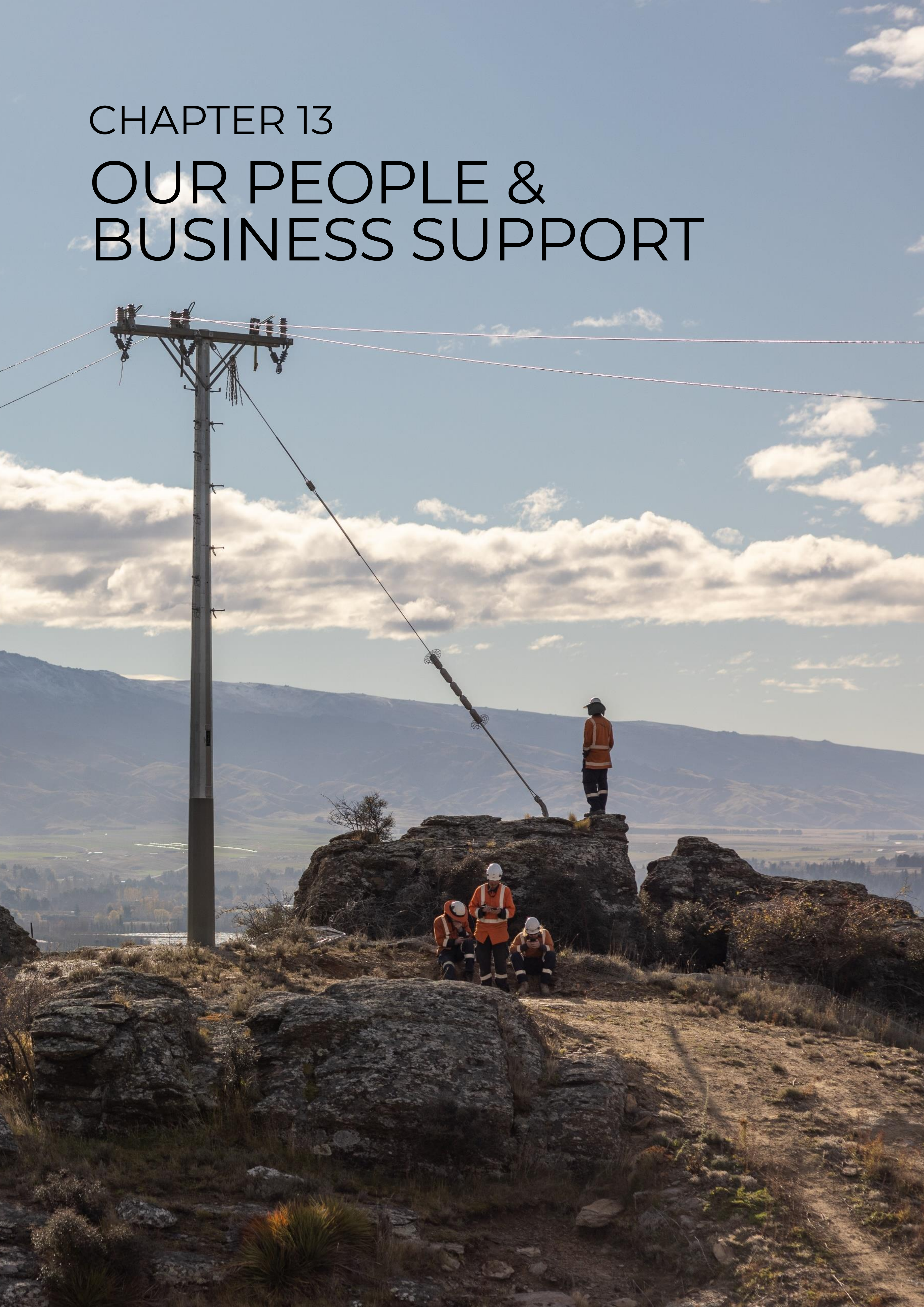
We have updated our forecasts for RY26 onward to reflect these new costs and used them with current vendor quotes to develop our projections for the remainder of the CPP period, DPP4, and beyond.

We have observed that an increasing number of solutions are now available only as platform or SaaS solutions. Consequently, we have adjusted our forecasts from capex to opex to reflect this change.

Our CPP proposal aimed at consolidating our ICT capabilities to ensure we can provide timely and reliable information from a consistent single source. Our plans for DPP4 build on that foundation by incorporating new digital capabilities necessary to support our business in an increasingly complex and dynamic environment.

CHAPTER 13

OUR PEOPLE & BUSINESS SUPPORT



Our Asset Management Plan is predominantly focused on physical distribution assets. But meeting the future demands on our network and business requires broader support. Our non-network business support, system operations, and network support functions play a vital role in our strategy and necessary transformation.

13.1. OUR PEOPLE

The energy sector in New Zealand is undergoing significant transformation. The pace of electrification and decarbonisation is driving higher-than-expected expenditure and changing the way we operate our network and the types of skills our people need to keep pace. Rapid technological advancements are reshaping the sector. For example, data management, cybersecurity and automation demands are requiring organisations with digital capabilities to deliver new or enhanced processes and services to enable systems integration and efficiency gains.

Consumer expectations of the energy sector are also evolving. On top of the traditional requirement to balance the energy trilemma of security of supply (reliability), sustainability and affordability, the uptake of distributed energy resources is driving growing demand for personalised services, energy efficiency and sustainable practices.

These changes require Aurora Energy to balance the people skills needed to maintain existing operations and consider the efficiencies that might be achieved through the deployment of digital technology to transform our business operations. Our non-network expenditure forecasts reflect our intention to balance resource levels prudently through carefully considered skills transition and acquisition plans that take into account the efficiencies we expect to gain from greater expenditure on digitisation and improved systems and processes.

To deliver on our key strategic initiatives and drive the digital transformation of our systems and processes, we need to invest in the skills of our teams. Developing our capability and investing in our people is essential to making the most of new systems. We continue to accelerate our capability through the implementation of automated people management systems and continued investment in our people via the Aurora Energy Leadership Programme.

We are also undertaking workforce planning to ensure we can transition our people into new roles where required and upskill them to meet the needs of the future. Growing local and available talent pools forms part of our strategy in a competitive market where we expect specific skills may be difficult to secure.

The Commerce Commission defines two categories of non-network operating expenditure: System Operations and Network Support (SONS) and Business Support (BS). In this section we provide an overview of our organisational team structure, describe the work of our teams, and outline the manner in which our people resources, including contractors and external support, are responding to a changing future.

13.1.1. Systems Operations and Network Support

The Systems Operations and Network Support (SONS) teams are focused primarily on asset management planning; network and engineering design; network operations including outage management, consumer connections and notifications; and procurement of network maintenance and asset construction services.

13.1.2. Asset Management and Planning

The five teams involved in asset management and planning are responsible for the overall direction and planning of our network infrastructure as well as planning for the evolution of our network to support a new energy future. These teams, as listed below, are also charged with the preparation of asset management and planning work programmes and network engineering designs.

- Strategic Capability
- Reliability Performance
- Asset Lifecycle
- Network Planning
- Engineering

13.1.3. Operations & Network Performance

The operations and network performance function covers the daily operation of the network. This encompasses control room functions, network access permissions, switching, public safety management, and operational planning for new and emerging technologies.

Three teams contribute to this function:

- Network Operations Management
- Operational Information and Fault Follow-up
- Network Performance and Operational Technology

13.1.4. Service Delivery

Service delivery encompasses the programming and issuing of work to contractors, overseeing contractor performance, procurement of network maintenance and asset construction services, and the project management and delivery of our many network projects in partnership with field services providers. This area is predominantly capital funded.

Five teams contribute to this function:

- Works Delivery
- Contractor Management
- Network Procurement
- Programme Delivery Performance
- Contractor Health and Safety

13.1.5. Customer & Connections

The teams providing our customer and connections function are responsible for the delivery of digitisation and process improvements to better position Aurora Energy for the changing future. These teams also oversee new connections to the network and work with key large connection consumers across our sub-networks, as well as managing stakeholder and consumer interfaces and reflecting these in stakeholder engagement and communications plans. They ensure stakeholders, including the community and consumers, have opportunities to provide feedback and input into future network planned expenditure.

Three teams contribute to this function:

- Customer Initiated Works
- Customer and Engagement
- Business Process and Change

13.1.6. Quality Assurance

Appropriate quality assurance processes and resources are essential to ensure our escalated level of planned works for the CPP period and beyond are delivered to all applicable industry standards. These processes are embedded within our Service Delivery team.

Our approach to improving quality assurance is currently focused on two key areas: works management capability and construction works quality assurance.

Within works management, we are introducing robust frameworks to identify and monitor quality risks during key project stages. To drive efficient delivery of capital and maintenance projects, we have rolled out continuous staff development in alignment with the PRINCE2 methodology. We also aim to roll out improvements to processes and systems to enable better reporting, risk monitoring and visualisation of project health, leading to more efficient works delivery.

Our quality assurance standard outlines the process for identifying and completing constructed works for review, as well as recording the results. We monitor quality assurance records through a monthly non-conformance and escalation process. Feedback is provided directly to service providers and resolutions are managed through regular meetings. Currently, we are enhancing our non-conformance reporting system to include additional quality assurance metrics and reporting.

We have broadened our quality assurance review process to encompass vegetation management. Additionally, we plan to include further inspection and maintenance tasks, connection services, and zone substation works. We will assess the necessary resourcing and internal development to fulfil the requirements of our enhanced quality assurance process.

13.2. BUSINESS SUPPORT

Our Business Support teams deliver the corporate functions such as human resources, accounting and finance, and information and communications technology, which support the day-to-day management of Aurora Energy as an electricity distribution business.

13.2.1. Finance, Risk, and Assurance

The teams delivering our finance, risk, and assurance functions handle our financial management, regulatory reporting, and pricing. These functions include financial budgeting and forecasting, regulatory disclosures and financial reporting processes, internal and external audit arrangements, pricing methodologies, and commercial contracts. These teams also oversee our enterprise risk management framework and manage external relationships with our regulators.

Three teams contribute to this function:

- Financial Planning and Analysis
- Accounting and Finance
- Risk, Assurance and Compliance

13.2.2. People, Culture and Safety

Our People, Culture and Safety group is responsible for the development, design and implementation of people-related frameworks, policies and practices, the health, safety and wellbeing of Aurora Energy staff, as well as oversight of organisational safety strategies.

There are two teams in this group:

- People and Culture
- Health & Safety

13.2.3. Digital Transformation

Our Digital Transformation group manages ICT systems and data governance strategies on behalf of Aurora Energy, and also oversees our overall digital transformation roadmap, which links directly to optimising business processes and preparing for the future. This team also delivers ICT services and manages our operational response and mitigation strategies for cyber security threats.

There are three teams in this group:

- Information and Intelligence
- Digital Delivery
- ICT Services

13.2.4. Business support opex

Our business support functions all support our electricity asset management activities. Opex related to these activities is classified as non-network opex.

Some of the key drivers for this expenditure over the planning period are:

- **Staff numbers:** This directly impacts business support costs. As our activity levels grow, we will require increasing numbers of capable staff. Salary and indirect costs (e.g. consumables) are driven by overall staffing levels.
- **External labour market:** Staff salaries and other benefits are influenced by the general employment market. Demand for skilled staff, particularly regionally, will impact the level of competitive salaries.
- **Business support requirements:** As our network work programme expands, work volumes for areas of support functions will increase and we need to be prudent about how we manage this balance.
- **Regulatory and compliance requirements:** We incur a range of costs to meet statutory obligations. This includes regulatory obligations under the Commerce Act (for example, auditing of Information Disclosure statements and price-path compliance statements) and auditing of financial statements.
- **ICT capability requirements:** Our staff numbers will increase as we deliver increased work volumes. As a result, the number of people using our ICT systems will increase. Licence agreements and costs for third-party support and hardware are impacted by headcount.
- **Insurance:** The cost of material damages, business interruption, and liability insurance cover has increased significantly in recent years. We expect this trend to continue in the context of the recent rise in insurance-related events.

Chapter 14

NON-NETWORK ASSETS

14.1. NON-NETWORK ASSETS

Broadly speaking, our non-network assets comprise buildings and storage site facilities, technology assets, and motor vehicles, which we own or lease for the purpose of asset management and business operations.

14.1.1. Facilities

We own or lease property facilities including office buildings and storage sites in Dunedin, Christchurch, and Central Otago. Our facilities management programme aims to ensure our offices and stores are safe and secure for employees and contractors, are functional and fit for purpose, support improved productivity and efficiency, and are cost-effective to procure and operate. They should also be sized to support future staff growth and changing materials storage requirements.

Table 14-1 summarises the location of our offices and storage sites, whether they are owned or leased, and the current utilisation of each facility. The facilities are strategically located throughout our network footprint. This has many advantages, including having employees with local knowledge close to consumers and service providers. The Christchurch office enables us to collaborate with industry counterparts and assists with our recruitment and retention strategies.

Table 14-1: Facilities assets

Region	Building Location		
Dunedin	Halsey Street	Leased	Main office and storage
	Fryatt Street	Leased	Control room
Central Otago	Ellis Street (Alexandra)	Owned	Storage, part leased to third party
	Barry Avenue (Cromwell)	Owned	Storage
	McNulty Road (Cromwell)	Leased	Main office and control room
	Success Street (Alexandra)	Leased	Storage
Christchurch	Sir Gill Simpson Drive	Leased	Christchurch office

Our network operations team is required to provide essential network access and operation services on a 24-hour, 7-day basis. The COVID-19 pandemic highlighted the benefit of being able to isolate our control rooms and the network operations team from other staff to minimise any spread of the virus. To ensure this team can work with minimal disruption in future, we have leased a separate office space for our Dunedin control room staff.

14.1.2.Technology assets

The office facilities we operate are fitted with furniture and workstations to accommodate our employees. The standard setup of a workstation includes a desk, chair, storage, laptop, computer screens, and mobile phones. Our offices also host meeting spaces and relevant office equipment required to operate effectively, such as printers, storage, and meeting room technology. These assets include:

- Desktop hardware
- Laptop hardware
- Monitors
- Video conferencing equipment
- Other peripherals (scanners, digital cameras)

The key driver of expenditure on these assets is the number of employees, which determines the volumes of desktop computers/laptops and related peripherals required to service their ICT needs.

14.1.3.Motor vehicles

We have a fully maintained fleet of vehicles that are leased over a range of terms. We lease all of our vehicles, apart from one or two speciality vehicles and trailers, which cannot be leased cost-effectively.

Our fleet comprises vehicles that fit defined criteria, including that they must have a five-star ANCAP safety rating, low emissions, and be fit for purpose (i.e., all-wheel-drive and with suitable ground clearance). Our approach to managing our vehicles fleet is documented in a company standard that sets out how we procure and permit the utilisation of company motor vehicles.

We periodically undertake lease versus ownership analysis for our vehicle fleet, including comparing the relative cost-effectiveness of fully maintained or company-maintained leases. Lease costs for selected vehicle types were sought from a range of leading fleet providers in New Zealand, with selection of a provider based on best fit, considering pricing, servicing, and location of support.

14.2. LIFECYCLE MANAGEMENT FOR NON-NETWORK ASSETS

14.2.1. Facilities

The maintenance of, renewal of, or variations to office buildings and storage facility arrangements are generally undertaken with reference to the terms of the relevant property lease.

Building maintenance is generally budgeted annually as a cost of Aurora Energy (as tenant), whereas structural repairs, extensions, improvements, etc. are generally managed as specific projects at the cost of the Landlord.

Existing lease arrangements are monitored via a centrally managed software solution, which supports the review of future facilities requirements in advance of lease renewal or expiry dates.

14.2.2. Technology assets

The maintenance and renewal of technology hardware and software is managed with reference to the expected useful life of the assets – generally three to five years for computer hardware, phones, and software assets.

Assets that are considered less than secure from a cyber risk perspective or unable to consistently perform their required function in an economic manner are replaced.

14.2.3. Motor vehicles

Our Company Motor Vehicle policy requires us to source, maintain, and manage the vehicles in our fleet taking safety, environmental, and economic considerations into account.

Vehicles that are considered unsafe (generally defined as less than a five-star ANCAP rating) or unable to consistently perform their required function in an economic manner are replaced. Our sustainability strategy is also such that we are committed to reducing carbon emissions and running costs by converting our light passenger vehicle fleet to electric or hybrid vehicles where economically and operationally feasible as leases expire. If conversion to electric or hybrid is not feasible, then a fuel-efficient model will be used.

The performance assessments we undertake consider the expected range, terrain, and cargo/towage requirements of the intended vehicle use. Economic assessments are based on the total cost of ownership, rather than purchase price alone, to account for the higher running costs of combustion engines as compared with electric vehicles.

Day-to-day fleet management services are currently outsourced to an external supplier.

F

COST & DELIVERY

CHAPTER 15

OUR NETWORK INVESTMENT

We forecast our expenditure for the electricity distribution network assets for the next 10 years to show how we are going to invest in our network and deliver services to consumers.

15.1. NETWORK EXPENDITURE OVERVIEW

Our capital expenditure and operational expenditure programmes are integral to the operation of our business throughout the 10-year forecast period. We have continued to focus on the delivery of these programmes in RY25.

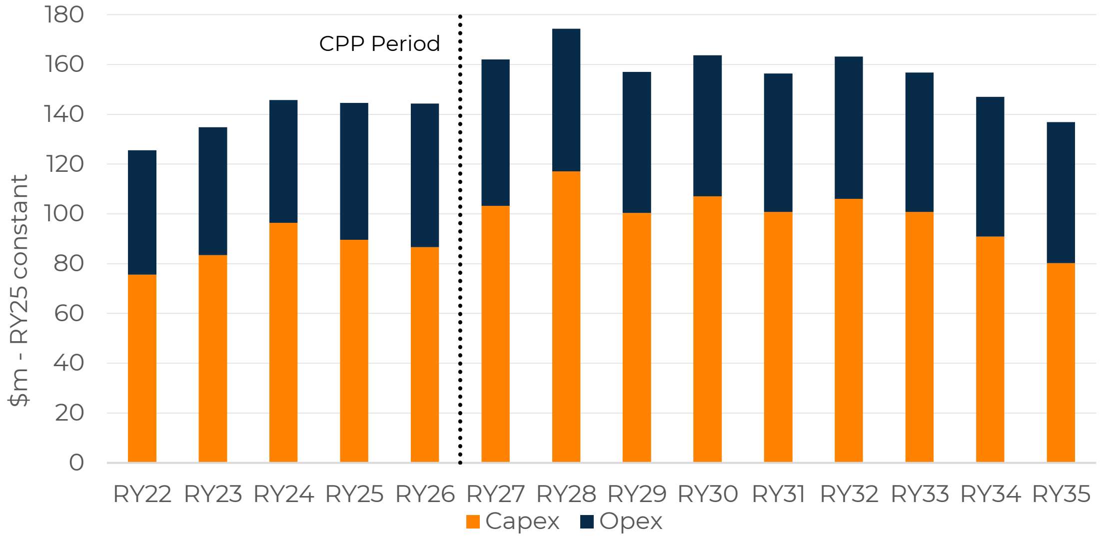
This chapter sets out our expenditure forecasts for the AMP period. It provides further commentary and context for our forecasts, including key assumptions, and discusses our cost estimation methodology and how this has been used to develop our forecasts.

The expenditure forecast categories presented here align with our internal expenditure categories and those used in our CPP proposal. The information presented here summarises the expenditure discussed in earlier chapters.

Our AMP includes our current best forecasts based on our asset management strategies and using available network information. As described in **Chapter 6**, we have improved the quality of our data through further development of our fleet strategies. Below, we summarise our capex and opex forecasts for the AMP planning period, together with cross-references to chapters where more detailed information is provided.

Figure 15-1 provides a summary of forecast expenditure for the period RY26 to RY35. Total expenditure for the 10-year period is $1.56 billion. All financial values are expressed in $RY25 constant price New Zealand dollars, except where specified otherwise.

Figure 15-1: Total capex and opex forecast



15.1.1. Future efficiencies

In line with our strategic objectives, Aurora Energy emphasises investment optimisation and deferral through intelligent partnerships and leveraging non-network solutions, enhancing asset management and delivering value to consumers.

COLLABORATIVE EFFORTS

Service Efficiency: Key service providers such as Delta, Electronet and Unison Contracting underpin our operational excellence. Their contributions are crucial for maintaining, renewing, and operating our distribution network efficiently, offering transparency and commercial prudence.

Distributed Generation: Our network incorporates distributed generation, such as hydro, solar and wind, as discussed in Section 3.1.5. This integration helps in reducing peak demand, thus deferring network expenditure and supporting New Zealand's decarbonisation goals.

Transpower Coordination: We maintain a relationship with Transpower for expenditure planning and operational integrity, ensuring the smooth functioning of the grid exit points that are pivotal to our distribution network.

NON-NETWORK SOLUTIONS

Third-Party Engagements: We deploy third-party Distributed Energy Resources (DER) to manage peak loads and defer costly network upgrades, as evidenced by our initiatives in the Upper Clutha region. Our partnership with a flexibility supplier has exemplified our commitment to smoothing demand peaks and deferring large capital expenditure.

DECISION-MAKING AND INVESTMENT OPTIMISATION

Strategic Framework: Our asset management strategy and framework, aligned with the ISO 55001 standard, guide all spending and operational decisions, ensuring continuous improvement and effective risk management.

ICT Investments: We harness ICT advancements for asset management, such as our enterprise asset management system (Maximo), to drive efficiencies in our renewals process and decision-making capabilities.

OUTCOME-FOCUSED INITIATIVES

Customer-centric Approach: We strive to drive efficiency into our design, procurement, and delivery, maximising value for consumers by putting them at the centre of decision-making.

Regulatory Compliance: Our operations and innovations comply with regulatory requirements, industry best practices, and a commitment to sustainable management.

15.2. CAPEX FORECAST

When developing our 10-year plan we were mindful of cost escalation and affordability for consumers and our shareholders. We have used the latest available asset condition inspection information to reduce expenditure on asset renewals, to make way for high priority growth related projects. In some cases, we have also applied engineering judgement where we believe future inspections are likely to indicate more favourable asset condition than the current data suggests.

We review and flex our plan as new information becomes available. Thus, while the capex graphs in this AMP reflect RY25 forecasts as at November 2024, Schedule 11a gives an updated view created in February 2025, taking into account higher than anticipated levels of capital expenditure.

Possible/probable growth-related major projects have been excluded from our plan and we will rely on capacity event reopener mechanisms when these projects become certain.

Our CPP period (RY22 to RY26) plan prioritises safety for the public, contractors, and staff. We have included modest levels of expenditure on reliability and resiliency as part of our reliability hotspot programme and seismic reinforcement of zone substation buildings.

As we progress through the forecasting period we will continue to focus on safety and meeting strong growth, including decarbonisation through electrification. However, we also propose to introduce reliability and resiliency programmes to:

- Enable reliability performance commensurate with the expectations of consumers and communities in areas of suboptimal performance; and
- Respond to stakeholder expectations for improved network resilience to climate change risks, storms, and other natural disasters.

Our reliability programme will include a continuation of the reliability hotspot programme, additional reclosers, remotely operable switches, and new fault passage indicators. In some locations, we will make network configuration changes (for example, splitting feeders) to improve reliability. We propose a targeted programme, with $11 million across the 10-year planning period.

Our resiliency programme will include the provision of additional spares and associated storage facilities, backup generation, and possible hardening of storm exposed assets.

We propose a modest but targeted programme, with $20 million across the 10-year planning period.

In addition, our asset renewals and growth programmes will continue to make integrated improvements to reliability and resiliency.

As outlined in our Annual Delivery Plan, we have made significant progress across the network in improving the health of safety-sensitive fleets, with the health of some fleets progressing ahead of our forecast. For some fleets, however, we have reprioritised our plan to ensure we meet our objective of reducing safety-related network risks as soon as practical. While our asset renewals programme continues to prioritise fleets with the highest inherent and/or residual risk on the network, we also continue to replace a modest level of assets in most lower safety risk fleets where asset health indicates an end-of-life asset, thereby addressing other risk types such as reliability and resiliency.

15.2.1. 10-year capex forecast

Figure 15-2 shows our capital expenditure forecast for the AMP planning period, as well as our forecast variance to our previous AMP.

Figure 15-2: 10-year capex forecast by sub-network, Total ($m RY25 constant)

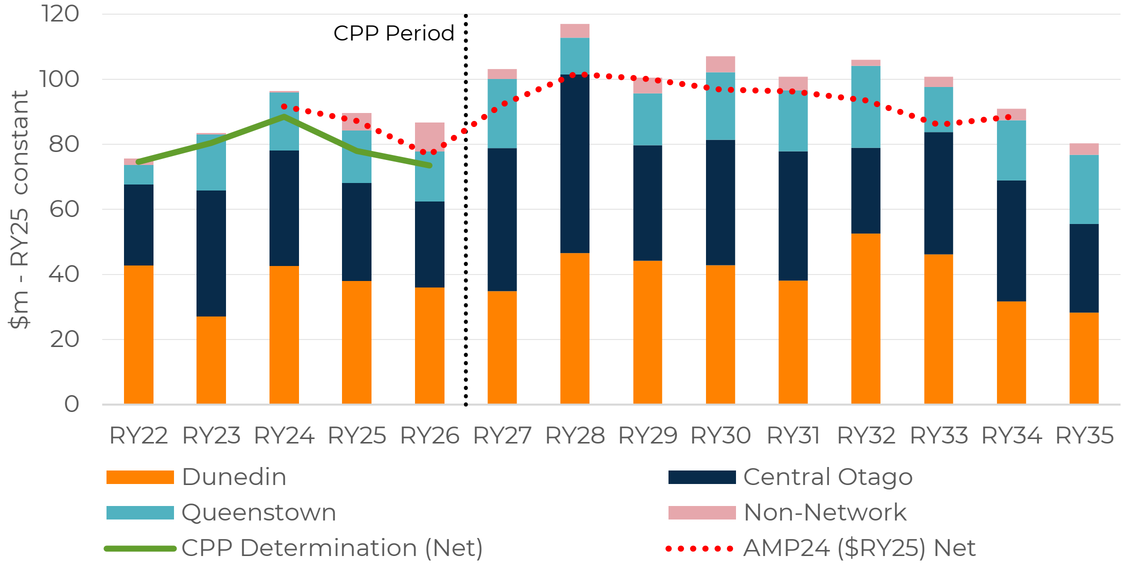


Table 15-1 shows our total forecast capital expenditure during the AMP planning period.

Table 15-1: 10-year capex forecast, Total ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Asset Replacement and Renewals	53.8	57.8	61.1	59.1	54.3	50.8	63.9	58.0	47.9	44.0
System Growth	11.0	28.1	36.6	21.9	33.5	30.9	25.8	25.8	25.6	18.9
Reliability, Safety and Environment	1.8	3.1	4.0	3.5	3.2	3.8	3.3	2.8	2.8	2.8
Customer Connections and Asset Relocations	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1
Non-network capex	8.9	3.1	4.2	4.8	4.9	4.2	1.9	3.1	3.5	3.5
Totals	**86.7**	**103.2**	**117.0**	**100.4**	**107.1**	**100.8**	**106.0**	**100.8**	**90.9**	**80.3**

DUNEDIN SUB-NETWORK

Table 15-2 shows our capital expenditure forecast for the Dunedin sub-network during the AMP planning period.

Table 15-2: 10-year capex forecast Dunedin ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Asset Replacement and Renewals	32.0	31.3	42.9	38.5	37.9	30.4	41.0	35.9	24.6	21.6
System Growth	0.3	0.3	0.3	0.7	1.2	3.7	7.6	6.4	3.3	2.8
Reliability, Safety and Environment	0.0	0.2	0.2	2.0	0.7	1.0	0.9	0.8	0.8	0.8
Customer Connections and Asset Relocations	3.8	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Non-network capex	5.3	1.8	2.5	2.9	2.9	2.5	1.1	1.9	2.1	2.1
Totals	**41.4**	**36.7**	**49.0**	**47.1**	**45.8**	**40.7**	**53.7**	**48.0**	**33.8**	**30.3**

CENTRAL OTAGO & WĀNAKA SUB-NETWORK

Table 15-3 shows our capital expenditure forecast for the Central Otago & Wānaka sub-network during the AMP planning period.

Table 15-3: 10-year capex forecast Central Otago & Wānaka ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Asset Replacement and Renewals	15.8	20.0	15.5	14.5	10.5	16.6	12.4	19.0	16.3	11.3
System Growth	5.7	17.6	31.5	15.2	21.7	16.7	7.6	12.5	14.8	9.8
Reliability, Safety and Environment	1.5	1.1	2.7	0.6	1.1	1.2	1.1	0.9	0.9	0.9
Customer Connections and Asset Relocations	3.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Non-network capex	2.2	0.8	1.0	1.2	1.2	1.0	0.5	0.8	0.9	0.9
Totals	**28.5**	**44.7**	**56.0**	**36.7**	**39.7**	**40.8**	**26.8**	**38.4**	**38.0**	**28.1**

QUEENSTOWN SUB-NETWORK

Table 15-4 shows our capital expenditure forecast for the Queenstown sub-network during the AMP planning period.

Table 15-4: 10-year capex forecast Queenstown ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Asset Replacement and Renewals	6.0	6.5	2.6	6.2	5.9	3.8	10.5	3.0	7.0	11.1
System Growth	5.0	10.2	4.8	6.0	10.6	10.5	10.5	6.9	7.5	6.3
Reliability, Safety and Environment	0.3	1.8	1.1	0.9	1.4	1.6	1.4	1.1	1.1	1.1
Customer Connections and Asset Relocations	4.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Non-network capex	1.4	0.5	0.7	0.8	0.8	0.7	0.3	0.5	0.5	0.5
Totals	**16.8**	**21.8**	**12.0**	**16.7**	**21.5**	**19.3**	**25.5**	**14.3**	**19.0**	**21.9**

CAPEX FORECAST VARIANCE FROM PREVIOUS AMP

The primary factor contributing to the increase in our forecasts is the cost escalation between AMP 2024 and AMP 2025. As mentioned in Section 15.2.1, our capex graphs and Table 15-5 reflect RY25 forecasts as at November 2024. We have since updated our schedules to reflect higher than expected capex expenditure. Our analysis of the CPP annual delivery report unit rates, along with insights from the recent major field service agreement (FSA) tender round, indicates that a 10–15% increase accurately reflects the current as-built costs.

Furthermore, as part of our CPP improvement plan we continue to improve our cost estimation model, to better estimate the cost of our major zone substation projects for both renewals and growth expenditure drivers. We are monitoring the cost of major projects, and the new process better captures the scope of projects and utilises an updated unit rate schedule. The second largest driver of an increase in our forecasts is a small number of large projects to support strong growth. For example, the Upper Clutha Capacity Upgrade project has increased system growth forecasts over the forecast period. Strong consumer connection growth is forecast to continue with recent connection activity supporting our forecast. Decarbonisation across all of our network further compounds strong growth in Central Otago.

Additional system growth expenditure is required to strengthen the subtransmission and 11 kV networks to meet strong consumer connection activity. Note that the upper Clutha Capacity Upgrade project is the driver for more than half of this increase.

We have increased the forecast levels of renewal expenditure over the next 10 years to address the risk posed by safety sensitive fleets.

For AMP 2025, we have considered the need for further investment in network renewals and network growth, as well as the need for increased non-network investment over the next 10 years.

Overall, these variances result in an increase in capital expenditure of approximately 13% over the reporting period.

Figure 15-3: AMP25 capex forecast variance from AMP24 forecast

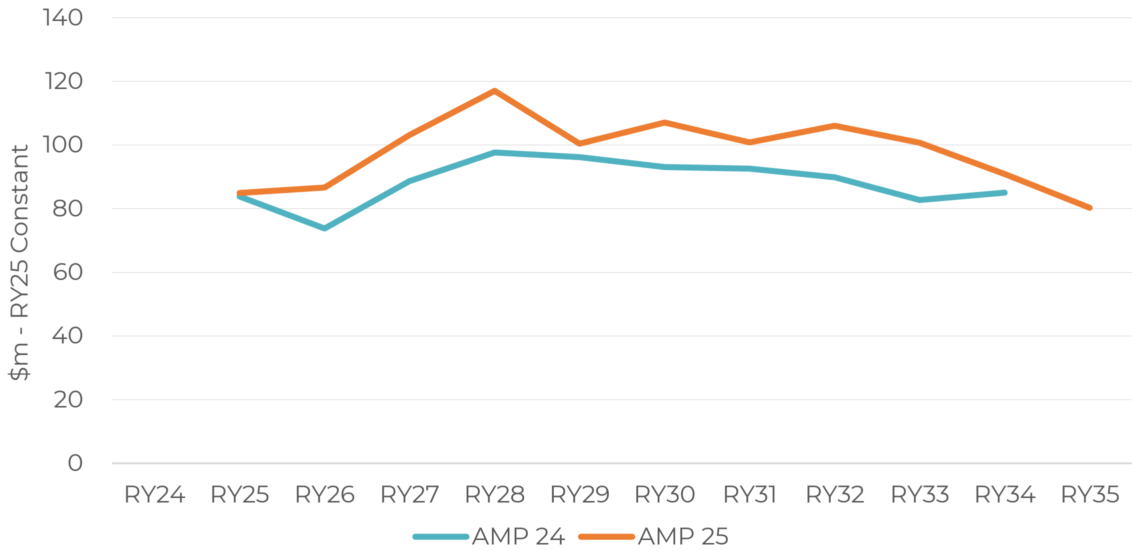


Table 15-5: AMP25 capex forecast variance from AMP24 forecast ($m RY25 constant)

AMP24-AMP25	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	Total
Consumer Connection	0.81	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	**4.41**
System Growth	0.95	-7.79	2.76	6.12	-3.86	16.67	7.19	1.30	3.63	1.67	**28.64**
Asset Replacement and Renewal	-1.54	12.98	11.72	9.36	5.46	-2.11	-1.25	14.96	13.82	4.21	**67.60**
Asset Relocations	5.87	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	**28.19**
Reliability, Safety and Environment	-0.06	1.21	1.08	0.88	-0.82	-2.02	-0.92	-0.92	-0.92	-0.92	**-3.41**
Non-network Assets	-0.21	5.95	-2.25	1.03	1.47	-0.64	1.19	-1.17	-0.50	-1.13	**3.74**
Totals	**5.81**	**15.23**	**16.20**	**20.26**	**5.13**	**14.79**	**9.09**	**17.05**	**18.91**	**6.70**	**129.17**

15.3. OPEX FORECAST

As detailed in Chapter 11, our network maintenance operational expenditure (opex) is defined in the four categories of *Preventive Maintenance*, *Corrective Maintenance*, and *Vegetation Management*. We use a base-step-trend model to inform expenditure forecast by category.

The summary of inputs for each model is captured in Chapter 11. The model outputs are detailed in this section, including an explanation of the variance in opex forecasts from AMP 2024 to AMP 2025. Non-network expenditure forms a significant part of our opex expenditure over the next 10 years as we keep pace with growth and technological advancements. Non-network opex has increased by approximately 13% from our previous AMP.

15.3.1. 10-year opex forecast

The figure and tables that follow are expressed in $RY25 Constant. While the opex graphs in this AMP reflect RY25 forecasts as at November 2024, Schedule 11b provides an updated view prepared in February 2025. This view reflects lower levels of RY25 opex, largely resulting from the deferral of new network and technology based initiatives pending negotiation and execution of commercial arrangements.

Figure 15-4: 10-year opex forecast by sub-network, Total ($m RY25 constant)

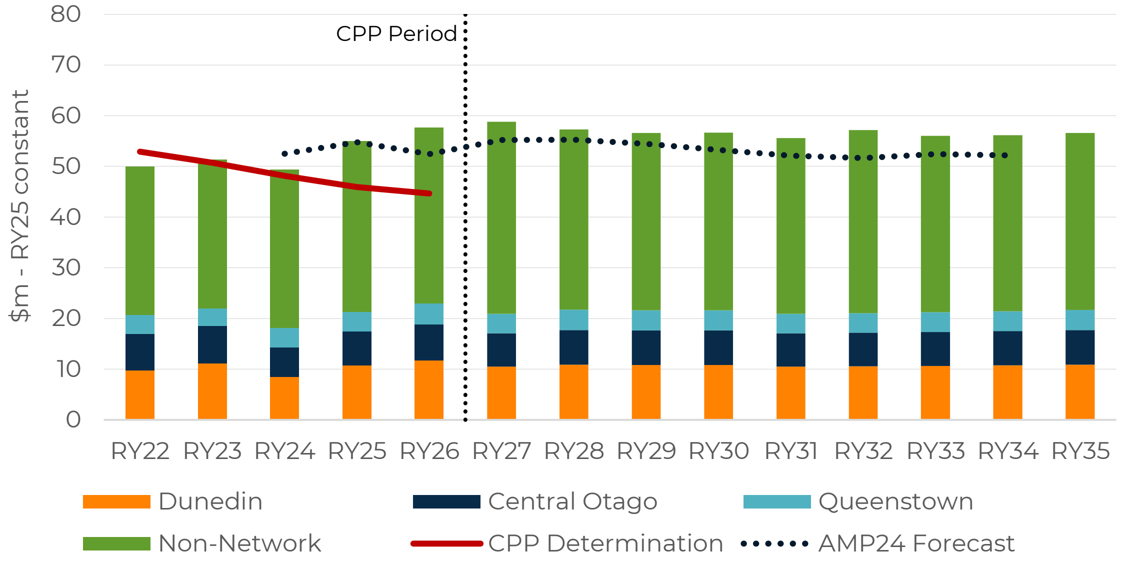


Table 15-6 shows our total network maintenance opex forecast during the AMP planning period.

Table 15-6: 10-year network maintenance opex forecast, Total ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Preventive Maintenance	6.5	7.2	7.8	7.8	8.0	7.4	7.5	7.5	7.6	7.7
Corrective Maintenance	7.5	4.0	4.2	4.2	4.2	4.0	4.0	4.0	4.1	4.1
Reactive Maintenance	4.6	4.5	4.5	4.5	4.5	4.6	4.6	4.7	4.7	4.8
Vegetation Management	4.4	5.2	5.2	5.1	4.9	5.0	5.0	5.0	5.1	5.1
SONS	19.2	19.8	19.7	19.8	19.8	19.7	21.0	19.8	19.7	19.8
Business Support	15.4	18.1	15.9	15.2	15.2	15.0	15.1	15.1	15.0	15.1
Totals	**57.7**	**58.8**	**57.3**	**56.6**	**56.7**	**55.6**	**57.2**	**56.1**	**56.1**	**56.6**

DUNEDIN SUB-NETWORK

Table 15-7 shows our network maintenance opex forecast for the Dunedin sub-network during the AMP planning period.

Table 15-7: 10-Year network maintenance opex forecast Dunedin ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Preventive Maintenance	2.9	3.2	3.4	3.4	3.5	3.3	3.3	3.3	3.4	3.4
Corrective Maintenance	4.1	2.2	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2
Reactive Maintenance	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7
Vegetation Management	2.2	2.5	2.6	2.5	2.4	2.4	2.4	2.4	2.5	2.5
Totals	**11.7**	**10.5**	**10.9**	**10.8**	**10.8**	**10.5**	**10.6**	**10.6**	**10.8**	**10.9**

CENTRAL OTAGO & WĀNAKA SUB-NETWORK

Table 15-8 shows our network maintenance opex forecast for the Central Otago & Wānaka sub-network during the AMP planning period.

Table 15-8: 10-year network maintenance opex forecast Central Otago & Wānaka ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Preventive Maintenance	2.4	2.7	2.9	2.9	2.9	2.7	2.8	2.8	2.8	2.8
Corrective Maintenance	2.3	1.2	1.3	1.3	1.3	1.2	1.2	1.2	1.3	1.3
Reactive Maintenance	1.2	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2
Vegetation Management	1.3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Totals	**7.2**	**6.6**	**6.8**	**6.8**	**6.8**	**6.6**	**6.6**	**6.7**	**6.7**	**6.8**

QUEENSTOWN SUB-NETWORK

Table 15-9 shows our network maintenance opex forecast for the Queenstown sub-network during the AMP planning period.

Table 15-9: 10-year network maintenance opex forecast Queenstown ($m RY25 constant)

AMP25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35
Preventive Maintenance	1.2	1.4	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.5
Corrective Maintenance	1.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Reactive Maintenance	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Vegetation Management	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Totals	**4.1**	**3.9**	**4.0**	**4.0**	**4.0**	**3.9**	**3.9**	**3.9**	**3.9**	**4.0**

OPEX FORECAST VARIANCE FROM PREVIOUS AMP

As shown in **Figure 15-5**, our overall opex forecast has increased over the period, from our previous AMP, by approximately 19%.

The model inputs, detailed by opex category, are described in **Chapter 11**. The following is a summary of the key factors contributing to the overall uplift in forecast:

- Efficiency gains from the introduction of new inspection programmes and enhancement of existing inspection programmes
- Increased defect find rate due to new and enhanced inspection programmes
- Reduction in our forecast for consumer pole inspection and remediation based on our latest information
- Core technology upgrades and intelligent network support
- Trend assumption of enhancement of network condition and performance
- Application of the Commerce Commission 2019 trend factor for change in network scale of 0.97% per annum to our forecast

As mentioned in **Section 15.3.1**, our opex graphs and **Table 15-10** below reflect RY25 forecasts as at November 2024. However, in February 2025 we updated our schedules to reflect opex which has been lower than anticipated due to deferral of new network and technology based initiatives.

Figure 15-5 and **Table 15-10** are provided to quantify the costs associated with the adjustments.

Figure 15-5: AMP25 opex forecast variance from AMP24 forecast

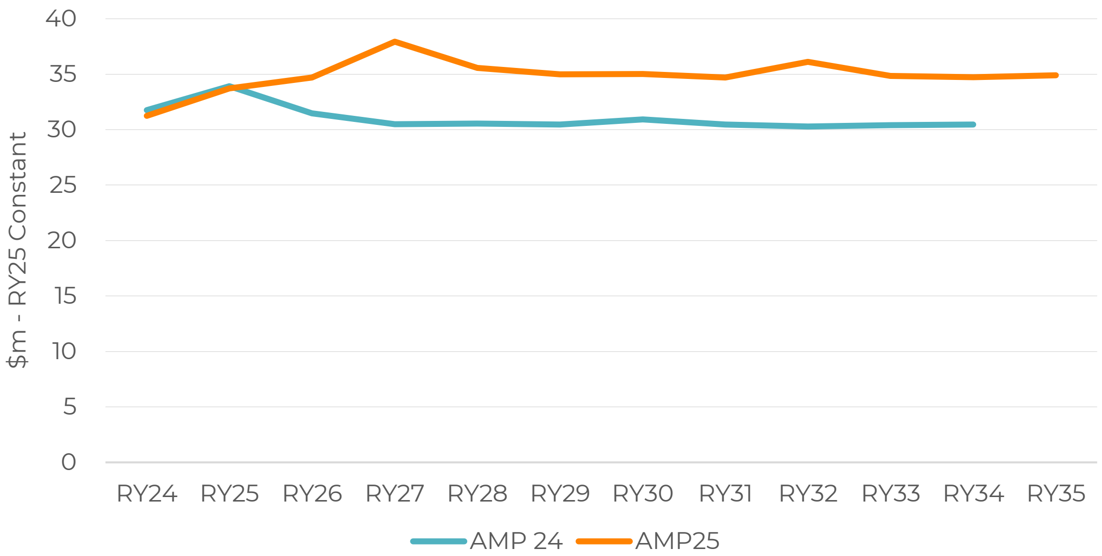


Table 15-10: AMP25 opex forecast variance from AMP24 forecast ($m RY25 constant)

AMP25	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	Total
Service Interruptions and Emergencies	0.59	1.00	0.95	0.94	0.94	0.89	0.90	0.90	0.90	0.91	**8.92**
Vegetation Management	0.26	0.51	1.34	1.35	1.18	1.07	1.08	1.06	1.16	1.17	**10.17**
Routine and Corrective Maintenance and Inspection	-0.49	0.47	-6.12	-5.29	-4.51	-2.65	-2.76	-2.26	-2.86	-2.37	**-28.85**
SONS											
SONS	1.18	2.81	3.15	3.11	3.11	3.00	3.01	4.78	3.23	3.22	**30.59**
Network Evolution	-0.55	-0.49	-0.08	-0.21	-0.09	-0.17	0.12	-0.21	-0.01	-0.11	**-1.80**
CPP Application Costs	-0.80	-0.39	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	**-1.24**
Upper Clutha DER Solutions	-0.05	-0.04	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	**0.03**
Business Support											
People	0.59	1.34	1.41	1.43	1.15	1.03	0.87	1.05	0.97	0.95	**10.78**
CPP Application Costs	-0.80	-0.39	-0.06		0.00	0.00	0.00	0.00	0.00	0.00	**-1.24**
ICT opex	0.48	0.53	3.08	0.74	0.40	0.36	0.38	0.34	0.39	0.35	**7.04**
Premises and Plant	0.16	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	**1.54**
Administration and Governance	-0.40	-0.29	-0.19	-0.23	-0.23	-0.29	-0.29	-0.28	-0.29	-0.29	**-2.79**
Total	**-0.19**	**3.24**	**7.43**	**5.02**	**4.52**	**4.10**	**4.23**	**5.83**	**4.44**	**4.27**	**42.90**

15.4. ANNUAL WORK PLAN

The annual works plan aligns with our approach when developing forecasts in the DPP4 period (and AMP period) to create a minimum viable plan to meet known growth-related deficiencies/gaps.

The drivers can differ between sub-networks. We continue to see significant growth in Wānaka and Queenstown, while growth in the Dunedin subnetwork remains modest.

Our revised forecasts indicate an urgent need for additional capacity if we are to avoid the risk of winter shutdowns in cold environments.

Meanwhile, key stakeholders such as the Queenstown Lakes District Council have clearly articulated their expectation for Aurora Energy to keep pace with growth in the region, as well as the importance of electricity as an enabler to achieving their zero carbon tourism goals.

In addition to the Upper Clutha regional development plan, we have a number of projects related to meeting capacity requirements or compliance with our security of supply guideline.

Table 15-11 highlights major projects in the sub-networks for the next regulatory year.

Table 15-11: Annual work plan RY26 ($m RY25 constant)

Major projects	Dunedin	Central Otago & Wānaka	Queenstown	Total
Dunedin Projects				
Smith Street 11 kV Switchboard Replacement	1.418	—	—	1.418
Green Island Substation Rebuild	2.153	—	—	2.153
Halfway Bush 11 kV Switchboard Replacement	1.445			1.445
Central Otago & Wānaka Projects				
Upper Clutha Engagement	—	0.600	—	0.600
New Queensberry zone substation	—	3.075	—	3.075

Major projects	Dunedin	Central Otago & Wānaka	Queenstown	Total
Dunstan Stage 2	—	0.657	—	0.657
Alexandra 33 kV and 11 kV Outdoor-Indoor Conversion	—	2.684	—	2.684
CM838 Feeder Stages 2 and 3		0.879		0.879
Queenstown Projects				
Malaghans (New Dalefield) zone substation	—	—	3.034	3.034
Queenstown – 33 kV & 11 kV Protection and Bus Upgrade	—	—	0.709	0.709
Fernhill Feeder Reconfiguration			1.234	1.234
Frankton Ripple Plant Upgrade			0.599	0.599
All Sub-networks				
LV Reinforcement	0.167	0.167	0.167	0.500
Totals	**5.183**	**8.062**	**5.743**	**18.988**

15.5. LIMITATIONS AND ASSUMPTIONS

In our AMP, we acknowledge that various factors of uncertainty can lead to material differences between the prospective information disclosed and the actual information recorded in future disclosures. While we recognise these factors, evaluating them with accuracy remains a challenge, as there is no specific method to quantify their impact (refer to Chapter 8).

Our planning and forecasting processes have inherent limitations, including variations in project scopes and uncertainties in risk assessments.

We acknowledge that although we are actively working on a more robust, systematic, and standardised approach to planning and forecasting, this is a process of continuous improvement as our systems develop and improve.

15.5.1. Approach to escalation

There are a number of inputs and assumptions underpinning our forecasts for the planning period. These include our approach to escalating our forecasts to nominal dollars. In developing our forecasts for the planning period, we address both major projects and volumetric programmes. Several processes, each requiring consideration of a range of factors, are involved in the creation of these forecasts.

We expect that the input price increases we face over the planning period will be greater than CPI due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets. This cost escalation between AMP24 and AMP25 is the predominant driver of our increased forecasts. We will continue to prioritise our renewals to best manage the impact of cost escalation on our planned risk reduction targets.

Our new escalators have been developed using forecasts of input price indices that reflect the various costs that we face, including material, labour, and overhead components sourced from an economic consultancy firm. These are applied using weighting factors for cost categories, such as conductor, that are impacted by the inputs. These were applied to our constant (RY25) forecasts to produce the nominal dollar forecasts for the Information Disclosure schedules in Appendix B.

Consultancy advice we have received included commentary outlining that whilst there is some level of uncertainty in the escalation forecasts, price pressures in the near term should return to their long-term paths. The most recent price increases from our suppliers have been incorporated into our RY25 constant dollar assumptions, where finalised information is available.

15.5.2. Volumetric estimates

Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. For volumetric programmes, we conduct a detailed analysis, separating unit rates into primary driving assets and coincidental works where possible. We re-evaluate calculated quantities and pricing for individual works components. The use of revised unit rates is integrated into the development of the 10-year forecast, enhancing accuracy and alignment with changing project dynamics.

Using this approach, we consider that our volumetric works will have appropriate estimates, given the following assumptions:

- Project scope is reasonably consistent and well defined.
- Unit rates based on historical outturns effectively capture the impact of past risks, and the aggregate impact of these risks across portfolios is unlikely to vary materially over time.
- A large number of future projects are likely to be undertaken, so the net impact of variances will tend to diminish given the greater number of projects.
- The volume of historical works is sufficiently large to provide a representative average cost.

For expenditure on non-network assets and systems (for example, IT hardware), we have used expected volumes and unit rates informed by a number of factors including discussions with vendors and historical outturns.

15.5.3. Tailored estimates

We have completed a cost estimation improvement initiative to better estimate the cost of our major growth projects and zone substation renewals. These are projects that we consider to be complex or high risk, or to have significant reputational impact or financial value.

For these projects, a thorough analysis is conducted to determine the appropriate sequencing and staging, ensuring optimal project execution. We carefully examine the required scope, breaking it down into manageable segments for accurate estimation. Drawing insights from similar past projects, we assess cost fluctuations, comparing planned versus actual expenses. We apply standardised methodologies for re-estimating major project components and develop and implement recommendations for continuous improvement.

15.5.4. Trending

We have used a trend-based approach to forecast part of our expenditure. This approach is used by many utilities for forecasting recurring expenditure. It is mainly used for forecasting reactive maintenance and certain trend-based capex forecasts, such as asset relocations.

The approach starts with selecting a representative year. The aim is to identify a recent year in which recurring expenditure is typical of what we expect in future years. If the year includes a significant event (for example, a major storm) an adjustment is made to remove its impact.

Expenditure in this typical year is then projected forward. To produce our forecasts, we adjust the resulting series for anticipated significant, non-recurring expenditure, permanent step changes, trends due to ongoing drivers, and any expected cost efficiencies.

15.5.5. Other forecasting inputs and assumptions

DEMAND FORECASTS

Historical relationships between proxy drivers (such as GDP) and demand growth continue to apply in the short term. We expect our demand forecasting approach (discussed in Chapter 9) to evolve over the next few years. In the medium term, the increasing adoption of new technologies may alter these underlying relationships, and we will monitor these trends carefully. Our expenditure planning approach is designed to ensure we do not invest in new capacity until we are sure it is required, which moderates the risk of over-investment. We will refine our approach to demand forecasting as part of our AMDP and will adapt our approach as our understanding evolves.

EMBEDDED GENERATION

Embedded generation will not have a material impact on network expenditure in the planning period. We have assumed that the installation of PV and energy storage will not materially affect peak load growth or related investment requirements over the planning period. The requirement for network reinforcement, which is largely driven by peak load, is therefore not anticipated to increase noticeably as a result of embedded generation.

HISTORICAL UNIT RATES

Historical unit rates for volumetric works reflect likely future scopes and risks at an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery, our experience has shown that increased efficiency tends to be offset by enhanced safety-related costs (such as traffic management) and increased costs associated with accessing the road corridor and private land.

15.5.6. Our approach to future efficiency adjustments

We plan to make material capability and capacity improvements over the AMP planning period. We anticipate potential efficiencies as we pursue planned business improvements, aligned with our commitment to continuous improvement and adaptability in response to evolving market conditions. The efficiencies are based on a combination of the following potential factors:

- **Contractor productivity:** Reflecting increased competitive tension and scale efficiencies that could be realised by the uplift in work, noting that these are offset by rising procurement costs associated with recent and ongoing global events
- **Works coordination:** Medium-term as we move from addressing spot risks to fleet-wide risks
- **Improved decision-making:** Driven by improved asset management, including expanded network analytics using better data; investment optimisation; and condition-based risk management
- **Improving capability:** Improvements as we mature our systems and processes, aligned with our ISO 55001 initiative. ICT expenditure (for example, implementation of our AMSS, IBM Maximo) is part of our strategic approach to enhance operational effectiveness, with the aim of achieving efficiencies where possible within the context of our asset management objective of affordability.

CHAPTER 16

HOW WE WILL DELIVER OUR PROGRAMME

We need to make sure we have the resources and capability to deliver our proposed programme of work efficiently and effectively

16.1. BUILDING OUR CAPACITY

16.1.1. Competency and training development plan

Aurora Energy is committed to aligning our competency growth plans with our forward-looking development strategies and asset management outlook. Our competency and training development plan is designed to support the business by targeting key areas identified in our AMMAT assessment. For more detailed information, refer to Section 6.7.

Focusing on the future, we recognise that the retention and attraction of critical skills, along with the investment in and development of our people, are pivotal to our strategic focus. Aurora Energy's RY25 Business Plan emphasises creating a positive work environment that fosters innovation and supports our people. Our People and Culture Plan is a key initiative under this strategy, aimed at enhancing staff training and development to ensure we remain an employer of choice and continue to attract and retain top talent.

16.1.2. Delivery requirements

This section describes the different approaches that we take to deliver projects and how these are managed.

OUTSOURCED DELIVERY

Aurora Energy operates an external contracting model. This means all work performed in the field, including both capital expenditure and operational expenditure, is delivered entirely by external field service providers. The external contracting model is underpinned by agreements that set agreed terms for the performance of work, including rates for labour, plant, and unit rated tasks. These agreements are referred to as *Field Service Agreements* (FSAs) and *Vegetation Service Agreements* (VSAs) and they deliver planned maintenance, reactive maintenance, vegetation management, and capital projects. Large capital projects are also sourced via our tendering process, which is open to a wider set of contractors.

Following extensive competitive tender processes to establish new contracting agreements for both field services and vegetations services, the following key Field Service Providers began operating on the Aurora Energy network from 1 April 2024:

- Delta Utility Services (Delta)
- ElectroNet Services (ElectroNet)
- Unison Contracting Services (Unison)

In addition to this, Delta and Asplundh are the Vegetation Service Providers performing vegetation maintenance on the Aurora Energy network.

The procurement methodology for field and vegetation services utilized external legal and procurement resources to ensure a fair and transparent process that met regulatory requirements. This approach ensured the selected contractors have the necessary capability and capacity to safely operate and maintain the network both in the short and long term.

In addition to field capability, our Engineering Services Panel provides us with access to design resource as required via agreements with three engineering consultancy services providers.

These arrangements ensure access to the skilled resources required to deliver our CPP programme, while providing a framework for improved service delivery and efficiency. The arrangements also allow for the increased use of competitive tendering and will lower the risk of under-delivery and help ensure we receive efficient and market-tested pricing.

Our Service Delivery team manages service provider contracts and the delivery of all network capital expenditure and operational expenditure. The delivery process relies upon technical standards to help ensure safety, quality, and cost-effectiveness. We have developed an extensive set of specific technical standards for design, procurement, installation, and maintenance. These standards are subject to ongoing review and improvement.

We have developed a plan that we know we can deliver. Throughout the CPP period we have successfully scaled up our internal and external works delivery capability. We have direct access to three tier-1 contractors within our field service contacts, with additional support from other approved contractors for major projects and volumetric work packages. We do not see deliverability as a reason to deliberately constrain our forecasts and plans, which are linked to safety and consumer outcomes. Cost escalation exacerbates the step up in expenditure, but the underlying quantities of work have not increased to the same extent, and therefore we have confidence in our ability to deliver our DPP4 and 10-year period plan.

WORKS PIPELINE

With the nature of Aurora's external contracting model, it is vitally important that Aurora provides a sustainable level work to its external field service providers with sufficient visibility of future changes in the level, and type, of work. It is also important that field service providers react to this information by ensuring they have sufficient resources to deliver the different types of work. One way we are communicating with our service providers is through the development of this asset management plan, we have shared with them information on the level and mix of work, with particular emphasis on the first three years of the period.

To further help ensure that sufficient resources are available, recognising that changes in service provider resources are often long-term initiatives, we have sought to structure an asset management plan that, where possible, has small consistent changes in work types and/or volumes over time, as opposed to large changes on a year-to-year basis. Feedback from our service providers is consistent that large sudden changes in work types and/or volumes can be difficult at times to resource, and whilst Aurora has options to engage other approved contractors to deliver work, most field capability will be met from our service providers.

DELIVERY OF NEW OR ALTERED CONNECTIONS

Aurora Energy's new way of planning and managing communication with consumers about new or altered connections is the Aurora Energy Customer Initiated Works (CIW) Contractor Portal, whereby an Authorised Network Contractor or Inspector requiring a new or altered connection submits a connection application to Aurora Energy. With this system, the contractor enters application data into the portal, which is then used by Aurora Energy to approve the applications and create ICPs where necessary. Upon submission of the application, all relevant parties are notified that the application has been submitted, via an email notification. Once an application is approved, again, approval is communicated to all parties via an email notification. Once the customer, network contractor (electrician), inspector, and retailer (new connections only) receive their approval notification, the job can be arranged to go ahead.

Once a job is complete and the inspector has filled out the livening report embedded in the portal application, Aurora Energy's database is updated, along with the Electricity Authority Registry (where applicable) and a final email notification is sent out to all relevant parties.

We acknowledge that customers sometimes experience delays with the delivery of network connections, which is often beyond Aurora Energy's control, as the timeframes are usually defined by the contractor. Information about the potential timeframes for new or altered connections is on our website.

To alleviate delays in network projects, growth and maintenance, Aurora Energy introduced the contractor model. This enables more network contractors to be authorised and available, so there are more options for consumers to engage contractors to do CIW work. We anticipate this approach will also help improve costs for consumers and Aurora Energy as a result of competition between contractors. Some of the delays that consumers commonly encounter despite this new process relate to material or contractor availability, or delays associated with obtaining resource or planning consents from local authorities or other landowners.

DELIVERY CONSIDERATIONS

DESIGN & CONSTRUCTION

To meet our targets for network safety as expressed in our CPP, we recognise a need to increase both the capacity and rate of delivery of our internal resources and field service providers. An additional consideration with current supply chain limitations is that improved productivity can be constrained by availability of trained personnel, plant, and materials. Good planning practices are essential to limit these potential hold-ups.

WORKS DELIVERY

Also used for other services (for example, detailed design as required), our external contracting model is set to maximise efficiency in cost and delivery, allowing our teams to focus more closely on our core areas of competency. This approach strikes an appropriate balance by allowing us to develop productive relationships with service providers, fostering innovation and incentive and control mechanisms, while also ensuring broader competitive tension through tendering in the wider market.

WORKS COST MANAGEMENT

For capital works we have developed a 'price-book' that considers works pricing across the NZ electricity distribution sector and recent pricing on our network. Prices (or unit rates) include design, project management and construction but exclude contingencies.

For volumetric work such as poles, we apply modified unit rates that consider the percentage of associated works that would be undertaken at the same time as a pole replacement. These are applied to our long-term forecasting and short-term budgets, knowing that the risk of variances in actual volumes and construction costs will generally average out across a large number of assets over time.

For low volume, major project work such as zone substation rebuilds, we go for competitive tender with contractors with suitable competency. As outlined earlier, the selected contractors for tender work are generally greater in number than the Field Service Providers, providing competitive tension in the pricing of major projects.

Our 10-year plan is reviewed every year, taking into account changes in demand, consumer preferences, and works coordination (see below). Typically, this results in a reprioritisation of projects and does not lead to significant changes in forecast costs. Customer-driven works can be dynamic and can lead to under or overspend of budgets in consumer connections and network reinforcement. These exceptions are managed as necessary through Delegated Financial Authority (DFA) and our Board.

We continue to improve our approach to cost-estimation. See Chapter 9 for our Cost Estimations Practices plan, as well as other key initiatives that we are undertaking. Our service delivery model seeks to ensure:

- A works delivery approach with clear accountability for core business functions
- Integrated works programming, scheduling, and governance capability to ensure a smooth and well-coordinated flow of work to the field
- An appropriate end-to-end expenditure planning and capital works process to enhance delivery efficiency, including taking a multi-year approach
- Appropriate end-to-end maintenance processes to enhance delivery efficiency
- Appropriate fault and emergency processes
- Effective procurement, safety management, and information architecture.

MAJOR PROJECTS DELIVERY

Our approach to managing works delivery is outlined below. This process focuses on major projects, but a similar process is followed for volumetric work.

DESIGN & CONSTRUCT

This stage includes detailed design, tendering, construction, project management, commissioning, and handover of new assets to operational teams.

To meet our targets for network safety as expressed in our CPP, we recognise a need to increase both the capacity and rate of delivery of our internal resources and field service providers. An additional consideration with current supply chain limitations is that improved productivity can be constrained by availability of trained personnel, plant, and materials. Good planning practices are essential to limit these potential hold-ups.

Work that is approved in the network development stage flows into the design and construct stage. At this point, the handover of capital projects from our network planning team to our delivery teams takes place. This phase covers detailed design, tendering, construction and project management, commissioning, and handover of new assets to the operational teams. The main activities in this phase (discussed below) include:

- Detailed design
- Procurement
- Construction
- Project close-out

These activities are managed by a dedicated project manager, who is responsible for ensuring the work is delivered on time, per specification, and within budget.

DETAILED DESIGN

Depending on the type and complexity of the work, detailed designs are undertaken by either our in-house design team, approved contractors, or design consultants.

When undertaking larger projects, detailed design is essential to maintain control over cost, quality, and timelines. The detailed design identifies construction methods to help minimise risks to safety and reliability. The Design/Engineering team is available for the duration of the project and will provide inputs such as design variations, should the need be identified during construction.

Design reviews take place at various stages of the project depending on project scale and complexity. Reviews cover safety, adherence to standards, technical requirements, and completeness. Design reviews are an opportunity for all departments to collectively appraise the robustness of a project, allowing for the consideration of input from a more diverse team.

Our design approach aims to standardise our network assets as much as reasonably practicable by following a suite of design standards and standard designs. Our standardised approach works well for typical installations and smaller defect jobs (business as usual), allowing for efficiencies in design, construction, maintenance, operations, and spares management.

Since 2017, we have continued to expand upon our existing document library (Controlled Document System) to include all requisite design, construction and maintenance standards, procedures, and forms. As these documents are developed and approved, they are made available online to our approved service providers. This has been a key development focus, as these standards help to simplify delivery and achieve long-term consistency across our network. Safety-in-design is a key driver for our design standards. We have also signed period supply agreements for 6.6/11 kV indoor switchgear and zone substation power transformers. These agreements will provide consistency in pricing, designs, and equipment spares, making both projects and lifecycle management of these assets more efficient.

PROCUREMENT

The procurement phase of projects includes tendering and other related processes. We have four Field Service Agreements (FSAs) with three service providers for undertaking capital and maintenance work (including fault and emergency response). Each FSA sets out the scope of services and the terms and conditions that apply, and is reviewed to ensure it maintains alignment with company policies and goals.

Large capital works are individually tendered on a case-by-case basis according to the requirements of the specific project or programme. We are monitoring the level of competition evident in our tender markets and will develop initiatives to increase competition where appropriate.

CONSTRUCTION

This process includes all commissioning, planning, construction, testing, livening, and handover of the asset to our operations and maintenance teams. Where appropriate, we prepare a commissioning plan to ensure all required activities are completed. We specify construction requirements that our service providers must follow and which may be included as part of the tendering documents.

Quality control over construction and commissioning works is critical to ensure our assets operate effectively and safely over their intended lives. Quality control ensures projects are constructed in a way that enables the design intentions, thereby limiting premature reactive maintenance in accordance with least whole-of-life cost principles.

While the primary responsibility for quality control over construction work lies with our service providers, we carry out regular quality checks and inspections on construction projects. These allow us to enforce high standards of work in compliance with our standards, ensure the required scope of work is being delivered, and verify that safe working practices are followed. The process is managed by the project managers using a mix of internal quality assurance officers and external technical resources.

PROJECT CLOSE-OUT

We undertake project close-out activities when the construction works are complete. These include:

- Confirmation that our asset information systems have been updated with as-built information
- Capitalisation of assets within the financial systems
- Archiving of relevant documentation
- Analysis of final costs to update our unit rates and costing assumptions (this function is currently being implemented and will be formally adopted following implementation of our asset management software solution)
- A review of lessons learned during the project, particularly regarding health and safety performance, with these lessons fed back into our planning and design processes

At project close, we report back to our planning team so they can review the performance of the design solution and its cost against our initial estimation and assess the overall success of the project. This is an essential step to ensure the ongoing improvement of our planning and design processes.

ASSET INFORMATION

We retain all specifications and asset information records in-house to ensure core asset knowledge is retained within the business. Further details on our Asset Information management are provided in Section 6.4.

APPENDICES

Appendix A: Glossary

Acronym	Meaning
AAC	All aluminium conductor
AAAC	All aluminium alloy conductor
ABC	Aerial bundled cable
ABS	Air break switch
ACSR	Aluminium conductor steel reinforced (cable)
ADMD	After diversity maximum demand
ADMS	Advanced distribution management system
ADR	Annual Delivery Report
AHI	Asset health indices
AI	Artificial intelligence
ALARP	As low as reasonably practicable
AMDP	Asset management development plan
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
AM&P	Asset Management & Planning
AMSS	Asset management software solution
ANCAP	Australasian New Car Assessment Program (car safety rating system)
BAU	Business as usual
BCP	Business continuity plan
BS	Business support
CAIDI	Consumer average interruption duration index
CAPEX	Capital expenditure
CB	Circuit breaker
CDS	Controlled documentation system
CIMS	Coordinated incident management system
CIW	Customer initiated works
CODC	Central Otago District Council
CoF	Consequence of failure
CPI	Consumer price index
CPP	Customised price-quality path
CT	Current transformer
DC	Direct current
DCC	Dunedin City Council
DCHL	Dunedin City Holdings Limited
DER	Distributed energy resource
DFA	Delegated financial authority
DGA	Dissolved gas analysis
DNO	Do not operate
DPP	Default price-quality path
DSM	Demand side management

DTM	Distribution transformer monitoring
EDB	Electricity distribution business
ENA	Electricity Networks Association
EOL	End of life (of an asset)
ERT	Emergency response team
EV	Electric vehicle
FME	Feature Manipulation Engine (data interpretation software)
FMECA	Failure Mode, Effects, and Criticality Analysis
FSA	Field service agreement
FTPP	Fast-tracked pole programme
GIS	Geospatial information system
GWh	Gigawatt hour
GXP	Grid exit point
HD	High definition (imaging)
HILP	High impact low probability (events)
HR	Human resources
HRC	High rupture current fuse
HV	High voltage
HWB	Halfway Bush
ICAM	Incident cause analysis method
ICP	Installation control point
ICT	Information communication technology
IEDs	Intelligent electronic devices
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Organization for Standardization
PRINCE2	Projects In Controlled Environments (management methodology)
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LiDAR	Light detection and ranging
LV	Low voltage
LVAC	Low voltage alternate current
MDI	Maximum demand indicator
MPL	Maximum practical life
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
N-1	Indication of power supply security. In the event of a failure, a backup supply will ensure that power is uninterrupted
NBS	New building standard
NEMA	New equipment or material assessment
NOC	Network Operations Centre

NZECP34	The New Zealand Electrical Code of Practice for Electrical Safe Distances
NZTA	New Zealand Transport Agency (Waka Kotahi)
ODAN	Oil-directed air-natural (power transformer cooling system)
OLTC	On-load tap changer
OMS	Outage management system
OPEX	Operational expenditure
ORC	Otago Regional Council
PILC	Paper insulated lead covered (cable)
PoF	Probability of failure
PSMP	Public safety management plan
PV	Photo voltaic (solar)
QLDC	Queenstown Lakes District Council
RC	Replacement cost
RCA	Root cause analysis
RMA	Resource Management Act 1991
RMP	Reliability management plan
RMU	Ring main unit (distribution switchgear)
RSE	Reliability, safety and environment (Capex)
RTU	Remote terminal unit
RY	Regulatory year (starting 1 April)
SAIDI	System average interruption duration index (minutes)
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition system
SF_6	Sulphur hexafluoride
SOI	Statement of intent
SOS	Security of supply
SONS	System Operations and Network Support
SWER	Single wire earth return
TDM	Time division multiplexing (digital communications technique)
TOA	
TRIFR	Total recordable injury frequency rate
VoLL	Value of lost load
VT	Voltage transformer
XLPE	Cross linked polyethylene (cable)

Appendix B: Disclosure Schedules

This appendix includes the following Information Disclosure Schedules:

11a	REPORT ON FORECAST CAPITAL EXPENDITURE
11b	REPORT ON FORECAST OPERATIONAL EXPENDITURE
12a	REPORT ON ASSET CONDITION
12b	REPORT ON FORECAST CAPACITY
12c	REPORT ON FORECAST NETWORK DEMAND
12d	REPORT ON FORECAST INTERRUPTIONS AND DURATION
13	REPORT ON ASSET MANAGEMENT MATURITY
14a	MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

Schedule 11a: Report on forecast capital expenditure

Company Name	Aurora Energy Limited
AMP Planning Period	

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	20,717	20,759	21,158	21,638	22,119	22,599	23,079	23,560	24,040	24,521	25,001
11		System growth	11,903	11,257	29,389	39,023	23,767	37,105	34,928	29,791	30,357	30,756	23,144
12		Asset replacement and renewal	59,698	54,951	60,359	65,039	64,240	60,301	57,545	73,949	68,407	57,603	53,981
13		Asset relocations	8,000	4,714	4,804	4,913	5,022	5,132	5,241	5,350	5,459	5,568	5,677
14		Reliability, safety and environment:											
15		Quality of supply	465	1,851	3,229	4,261	3,812	3,560	4,318	3,828	3,314	3,380	3,447
16		Legislative and regulatory											
17		Other reliability, safety and environment											
18		**Total reliability, safety and environment**	465	1,851	3,229	4,261	3,812	3,560	4,318	3,828	3,314	3,380	3,447
19		**Expenditure on network assets**	100,784	93,532	118,940	134,875	118,959	128,697	125,111	136,477	131,577	121,827	111,249
20		**Expenditure on non-network assets**	5,320	9,102	3,209	4,505	5,235	5,505	4,812	2,185	3,696	4,218	4,258
21		**Expenditure on assets**	106,104	102,635	122,149	139,379	124,195	134,201	129,923	138,662	135,273	126,045	115,508
22													
23	*plus*	Cost of financing	970	1,011	1,230	1,423	1,246	1,357	1,304	1,400	1,358	1,249	1,125
24	*less*	Value of capital contributions	17,755	14,119	14,390	14,717	15,043	15,370	15,697	16,024	16,350	16,677	17,004
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	89,319	89,526	108,989	126,085	110,397	120,188	115,530	124,039	120,280	110,617	99,629
28													
29		Assets commissioned	72,830	110,974	101,100	141,215	99,833	129,828	113,228	103,729	133,089	95,042	109,839
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31													
32			**$000 (in constant prices)**										
33		Consumer connection	20,717	20,311	20,311	20,311	20,311	20,311	20,311	20,311	20,311	20,311	20,311
34		System growth	11,903	11,030	28,135	36,627	21,898	33,476	30,868	25,800	25,764	25,593	18,897
35		Asset replacement and renewal	59,698	53,796	57,751	61,056	59,130	54,337	50,790	63,933	57,969	47,901	44,005
36		Asset relocations	8,000	4,612	4,612	4,612	4,612	4,612	4,612	4,612	4,612	4,612	4,612
37		Reliability, safety and environment:											
38		Quality of supply	465	1,811	3,100	4,000	3,500	3,200	3,800	3,300	2,800	2,800	2,800
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	-	-	-	-	-	-					
41		**Total reliability, safety and environment**	465	1,811	3,100	4,000	3,500	3,200	3,800	3,300	2,800	2,800	2,800
42		**Expenditure on network assets**	100,784	91,560	113,910	126,606	109,451	115,936	110,381	117,956	111,456	101,217	90,624
43		Expenditure on non-network assets	5,320	8,906	3,081	4,228	4,807	4,947	4,235	1,884	3,122	3,494	3,460
44		**Expenditure on assets**	106,104	100,466	116,991	130,835	114,259	120,884	114,616	119,839	114,579	104,710	94,084
45													

Difference between nominal and constant price forecasts

$000	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	-	448	847	1,327	1,808	2,288	2,768	3,249	3,729	4,210	4,690
System growth	-	227	1,253	2,396	1,868	3,629	4,060	3,991	4,592	5,164	4,247
Asset replacement and renewal	-	1,156	2,608	3,982	5,110	5,963	6,755	10,016	10,438	9,702	9,977
Asset relocations	-	102	192	301	410	520	629	738	847	956	1,065
Reliability, safety and environment:											
Quality of supply	-	40	129	261	312	360	518	528	514	580	647
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	40	129	261	312	360	518	528	514	580	647
Expenditure on network assets	-	1,972	5,030	8,268	9,508	12,760	14,730	18,522	20,121	20,611	20,625
Expenditure on non-network assets	-	196	128	276	428	557	577	301	573	724	799
Expenditure on assets	-	2,169	5,158	8,545	9,936	13,317	15,307	18,823	20,694	21,335	21,424

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

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

*Consumer types defined by EDB**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
Consumer Connection	20,717	20,311	20,311	20,311	20,311	20,311
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	20,717	20,311	20,311	20,311	20,311	20,311
less Capital contributions funding consumer connection	12,265	10,650	10,649	10,649	10,649	10,649
Consumer connection less capital contributions	8,452	9,661	9,662	9,662	9,662	9,662

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	2,827	610	7,846	21,575	9,807	17,583
Zone substations	7,850	7,365	12,514	6,117	2,937	9,487
Distribution and LV lines	945	500	3,711	7,118	7,914	5,033
Distribution and LV cables	84	2,506	4,065	1,817	1,239	1,373
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	198	48	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	11,903	11,030	28,135	36,627	21,898	33,476
less Capital contributions funding system growth						
System growth less capital contributions	11,903	11,030	28,135	36,627	21,898	33,476

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	439	7,343	8,008	12,390	15,510	9,505
Zone substations	15,789	9,379	8,058	11,786	6,724	7,192
Distribution and LV lines	30,470	18,894	24,591	20,199	19,351	21,569
Distribution and LV cables	2,759	2,636	2,555	2,555	2,555	2,555
Distribution substations and transformers	707	2,063	1,147	1,721	1,648	1,990
Distribution switchgear	8,597	9,312	9,023	9,023	9,023	8,948
Other network assets	937	4,168	4,369	3,381	4,319	2,577
Asset replacement and renewal expenditure	59,698	53,796	57,751	61,056	59,130	54,337
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	59,698	53,796	57,751	61,056	59,130	54,337

11a(v): Asset Relocations

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
Asset Relocations	8,000	4,612	4,612	4,612	4,612	4,612
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	8,000	4,612	4,612	4,612	4,612	4,612
less Capital contributions funding asset relocations	5,490	3,165	3,165	3,165	3,165	3,165
Asset relocations less capital contributions	2,510	1,447	1,447	1,447	1,447	1,447

11a(vi): Quality of Supply

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
RSE	465	1,811	3,100	4,000	3,500	3,200
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	465	1,811	3,100	4,000	3,500	3,200
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	465	1,811	3,100	4,000	3,500	3,200

11a(vii): Legislative and Regulatory

Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

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

Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Non-Network Assets	5,320	8,906	3,081	4,228	4,807	4,947
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - routine expenditure						
Routine expenditure	5,320	8,906	3,081	4,228	4,807	4,947
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	5,320	8,906	3,081	4,228	4,807	4,947

Schedule 11b: Report on forecast operational expenditure

Company Name	**Aurora Energy Limited**
AMP Planning Period	

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		3,738	4,689	4,743	4,848	4,954	5,060	5,217	5,376	5,539	5,703	5,871
11	Vegetation management		4,323	4,512	5,433	5,596	5,553	5,498	5,667	5,777	5,949	6,123	6,299
12	Routine and corrective maintenance and inspection		12,839	14,295	11,697	12,800	13,137	13,621	12,969	13,408	13,739	14,171	14,669
13	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
14	**Network Opex**		20,900	23,496	21,873	23,245	23,643	24,178	23,853	24,561	25,226	25,997	26,839
15	System operations and network support		17,378	19,581	20,666	21,008	21,547	22,076	22,387	24,358	23,337	23,670	24,258
16	Business support		14,877	15,807	18,974	16,965	16,608	16,923	17,072	17,528	17,892	18,209	18,627
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	145	114	32	32	33	33	-	-	-	-	-
18	**Non-network opex**		32,400	35,502	39,672	38,005	38,187	39,032	39,459	41,886	41,229	41,880	42,885
19	**Operational expenditure**		53,300	58,998	61,545	61,250	61,831	63,211	63,311	66,448	66,455	67,876	69,724
20			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
21													
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		3,738	4,583	4,536	4,534	4,533	4,532	4,576	4,620	4,665	4,710	4,756
24	Vegetation management		4,323	4,410	5,196	5,233	5,081	4,924	4,971	4,964	5,010	5,056	5,102
25	Routine and corrective maintenance and inspection		12,839	13,974	11,192	11,970	12,013	12,186	11,357	11,498	11,542	11,667	11,842
26	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
27	**Network Opex**		20,900	22,967	20,924	21,738	21,627	21,642	20,903	21,082	21,217	21,434	21,700
28	System operations and network support		17,378	19,132	19,742	19,648	19,738	19,816	19,699	21,019	19,756	19,665	19,786
29	Business support		14,877	15,448	18,140	15,866	15,199	15,162	14,980	15,071	15,080	15,050	15,103
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	145	112	31	30	30	30	-	-	-	-	-
31	**Non-network opex**		32,400	34,692	37,913	35,544	34,967	35,008	34,679	36,090	34,836	34,715	34,889
32	**Operational expenditure**		53,300	57,659	58,837	57,283	56,594	56,650	55,583	57,172	56,053	56,149	56,588
33	**Subcomponents of operational expenditure (where known)**												
35													
36	Energy efficiency and demand side management, reduction of energy losses												
37	Direct billing*												
38	Research and Development												
39	Insurance												
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
42													
43			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
44													
44													
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	106	207	314	421	528	641	756	874	993	1,115
47	Vegetation management		-	102	237	363	472	574	696	813	938	1,066	1,197
48	Routine and corrective maintenance and inspection		-	321	505	830	1,123	1,435	1,612	1,910	2,197	2,503	2,827
49	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
50	**Network Opex**		-	529	949	1,506	2,016	2,536	2,949	3,479	4,009	4,563	5,139
51	System operations and network support		-	449	924	1,360	1,808	2,260	2,688	3,339	3,581	4,005	4,473
52	Business support		-	358	834	1,099	1,409	1,761	2,092	2,458	2,812	3,160	3,524
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	3	1	2	3	3	-	-	-	-	-
54	**Non-network opex**		-	810	1,759	2,461	3,220	4,024	4,780	5,796	6,393	7,164	7,997
55	**Operational expenditure**		-	1,339	2,708	3,967	5,237	6,560	7,729	9,275	10,402	11,727	13,136
56													
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*												

Schedule 12a: Report on asset condition

Company Name	**Aurora Energy Limited**
AMP Planning Period	

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

sch ref	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
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.	0.29%	0.68%	1.08%	47.61%	50.34%		3	0.50%
11	All	Overhead Line	Wood poles	No.	1.33%	2.34%	28.08%	50.51%	17.74%		3	3.90%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-		N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	12.77%	1.67%	2.93%	6.12%	76.51%		2	6.14%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-		N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	0.11%	2.79%	97.10%		2	0.09%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	42.42%	15.45%	42.13%		2	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	100.00%	-	-		2	48.47%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	57.11%	27.79%	15.10%		2	53.60%
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.	37.83%	2.70%	8.11%	16.22%	35.14%		2	10.81%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-		N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	66.67%	33.33%		2	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	10.34%	4.60%	8.05%	25.29%	51.72%		2	19.54%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-		N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	25.91%	-	16.06%	6.22%	51.81%		2	16.58%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.00%		2	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-		N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	18.75%	81.25%		2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	14.33%	-	20.56%	20.25%	44.86%		3	18.38%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5.26%	2.63%	28.95%	36.84%	26.32%		2	57.89%
35												

					Asset condition at start of planning period (percentage of units by grade)							
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.	3.13%	14.06%	12.50%	21.87%	48.44%		3	14.10%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.87%	2.03%	5.81%	15.84%	72.45%		2	4.92%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-		N/A	-
42	HV	Distribution Line	SWER conductor	km	-	100.00%	-	-	-		2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.03%	0.64%	-	0.23%	99.10%		2	0.67%
44	HV	Distribution Cable	Distribution UG PILC	km	-	0.04%	0.21%	8.92%	90.83%		2	0.17%
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.	-	-	6.89%	3.45%	89.66%		2	17.24%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.26%	2.63%	28.95%	36.84%	26.32%		2	57.89%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11.00%	2.70%	5.30%	11.27%	69.73%		2	8.38%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	12.66%	14.67%	23.67%	16.67%	32.33%		2	48.33%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.49%	9.14%	22.22%	3.94%	64.21%		3	13.37%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	4.07%	1.72%	8.69%	12.88%	72.64%		3	7.26%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.18%	0.21%	1.92%	6.81%	90.88%		3	1.15%
53	HV	Distribution Transformer	Voltage regulators	No.	12.50%	-	-	43.75%	43.75%		3	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	8.26%	0.95%	6.25%	14.14%	70.40%		2	2.39%
56	LV	LV Cable	LV UG Cable	km	2.65%	1.30%	0.68%	6.13%	89.24%		2	
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.77%	0.73%	2.19%	12.88%	82.43%		1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	-	N/A	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	42.98%	4.21%	14.80%	13.01%	25.00%		3	53.06%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-		N/A	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%	-	4	-
62	All	Load Control	Centralised plant	Lot	25.00%	-	-	75.00%	-	-	2	-
63	All	Load Control	Relays	No.	25.00%	-	62.50%	12.50%	-		3	75.00%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Schedule 12b: Report on forecast capacity

Company Name	Aurora Energy Limited
AMP Planning Period	

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	supply classification +5 yrs (type)	Peak load period +10 yrs	available capacity +10 yrs (MVA)	available capacity +10 yrs (MVA)	supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	constraint solution remaining lifespan	Explanation
8			*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Required before*	*Required before*	*Required before*	*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*before DY2025*	*before DY2025*	*before DY2025*	*Not Required before DY2025*	*before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
9	Alexandra	11	Winter	15	N-1 switched	No constraint	3.7	Winter	1.7	N-1	Winter	0.2	0.2	N-1	Capacity	10+	Not applicable	Not applicable	Not applicable	Not applicable	
10	Clyde/Earnscleugh	4	Summer	4	N	Capacity	-0.4									1		Divert load to alternative substation	Implementation stage	1 - 3 years	Due to aging assets, Clyde/Earnscleugh (CE) substation will be replaced by new Dunstan substation (aimed to be completed by RY27). We will transfer all CE load in RY28 and decommission CE by RY28. We have reinforced the CE distribution network to provide better back-up from Alexandra substation. We currently divert load to Alexandra substation during summer peak period.
11	Earnscleugh	-	[Select one]	2	N	No constraint	2		0			0	0				Not applicable	Not applicable	Not applicable	Not applicable	Earnscleugh substation provides short term partial back up to CE substation. We plan to decommission Earnscleugh substation when the distribution feeders of CE have been transferred to the new Dunstan substation by RY28.
12	Ettrick	2	Autumn	4	N	No constraint	1.8	Autumn	1.7	N	Autumn	1.7	1.7	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	The substation is scheduled to be renewed in RY33. This provides an oppurtunity to install a standard transformer size and 11kV switchgear to reconfigure the distribution network to uplift reliability. This work would also increase transfer capacity to Roxburgh substation.
13	Lauder Flat	1	Summer	3	N	No constraint	2	Summer	1.7	N	Summer	-0.3	1.4	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	security) supplies Omakau and Lauder Flat substations. The said subtransmission is limited by the squirrel conductors in the circuit. We plan to replace the said conductors of Alexandra-Omakau subtransmission line by RY28 -30. The Lauder Flat zone transformer is planned to be replaced in RY31. There is an oppurtunity to supply Lauder Flat load with two feeders from the new Omakau substation and decommission Lauder Flat substation instead of replacing the transformer.
14	Omakau	3	Summer	8	N	No constraint	4.6	Summer	3.2	N	Summer	-7.1	1.8	N	Capacity	5	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	Omakau and Lauder Flat substations. The said subtransmission is limited by the squirrel conductors in the circuit. We plan to replace the said conductors of Alexandra-Omakau subtransmission line by RY28 -30. We are rebuilding a new Omakau substation with a higher transformer capacity in a different location which is planned to be completed in RY25.
15	Roxburgh	2	Spring	5	N	constraint	2.7	Spring	2.2	N	Spring	1.5	1.5	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
16	Camp Hill	6	Summer	8	N	No constraint	1.3	Summer	-0.3	N	Summer	-2.1	1.2	N	Capacity	10+	Not applicable	Not applicable	Not applicable	Not applicable	There is strong growth in the Camp Hill (CH) substation network area. We plan to install fans to increase transformer capacity to 10MVA in RY27. Further, we plan to build a new substation (Luggate) in RY29-31 and transfer some load of CH.
17	Cardrona	5	Winter	24	N	No constraint	19.2	Winter	14.6	N	Winter	7.9	12.9	N	Security	5	Subtransmission circuit	Not applicable	Not applicable	Not applicable	a higher capacity transformer at Cardrona substation. The said substation is currently an N security substation. We plan to build another 66kV line to increase security of supply in RY33-35.
18	Cromwell	15	Winter	24	N-1	constraint	9.1	Winter	4.6	N-1	Winter	1.4	1.4	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
19	Lindis Crossing	8	Summer	10	N	No constraint	1.6	Summer	0.8	N	Summer	0.5	0.6	N	Capacity	10+	Zone substation transformer	Divert load to alternative substation	Solution confirmed	Not applicable	(QB) substations is growing. We plan to transfer some load of Lindis Crossing substation to the new substation that would replace QB substation. Further, we plan to upgrade portion of the feeders that links the two N security substations to increase transfer capacity.
20	Queensberry	3	Summer	4	N	No constraint	1.1	Summer	0.7	N	Summer	0.1	1.8	N	Capacity	5	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	The demand on both LC and QB substations is growing. We plan to build a new substation with higher capacity from RY25 to RY28 to replace the existing QB substation and decommision the old substation.. Upon completion, some LC load will be transferred to the new substation. Further, we plan to upgrade portion of the feeders that links the two N security substations to increase transfer capacity.
21	Wanaka	27	Winter	24	N-1	Security	-3.1	Winter	-9.5	N-1	Winter	-7.1	-2.5	N-1	Capacity	1	Zone substation transformer	Divert load to alternative substation	Solution confirmed	1 - 3 years	We plan to install a 24MVA transformer in RY27 at the Riverbank switching station and transfer some Wanaka substation load on the same year. Operationally, we have the capabiity to move >1.5MVA load to Cam Hill substation.
22	Arrowtown	11	Winter	10	N-1 switched	Security	-0.5	Winter	0.4	N-1 switched	Winter				Capacity	2	Zone substation transformer	Divert load to alternative substation	Solution confirmed	1 - 3 years	The substation is planned to be renewed at the later part of the 10-year plan. The demand in the network area of Arrowtown substation (AT) will be above its firm capacity by RY26. We plan to build a new substation (Malaghans) and transfer some load of AT to the new Malaghans substation in RY30. A new substation (Whitechapel) is planned to be built by RY31-33 and AT load will be transferred by RY33-35 .

23	Commonage	12	Winter	17	N-1 switched	constraint	4.7	Winter	3.6	N-1 switched	Winter	1.7	2.5	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
24	Coronet Peak	6	Winter	6	N	No constraint	0.5								Capacity	5	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	The substation load is projected to increase. We plan to build a new substation (Malaghans) and transfer Coronet Peak substation load to the new substation in RY30. After the load transfer, Coronet Peak substation will be decommissioned.
25	Dalefield	2	Winter	4	N	No constraint	1.6								Capacity	5	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	The Dalefield substation network area demand is growing and projected to be above its capacity. We plan to build a new substation (Malaghans) in RY25-28 with higher capacity and N-1 security level. Further, we will rationalise the distribution network in the Dalefield, Arthurs Point, and Speargrass area which is currently fed by substations - Dalefield, Frankton and Arrowtown. We plan to transfer the loads in these areas to the new Malaghans substation in RY28-30. After the load transfer, Dalefield substation will be decommissioned.
26	Fernhill	7	Winter	10	N-1 switched	No constraint	3.2	Winter	0.3	N-1 switched	Winter	-1.9	-0.8	N-1	Security	None	Zone substation transformer	Network upgrade	Planning stage	Not applicable	The demand of the Queenstown subtransmission which supplies substations - Queenstown, Fernhill and Commonage is forecast to be above its firm capacity in RY31. We plan to upgrade the limiting sections of the subtransmission to increase its capacity and security by RY30-31.
27	Frankton	20	Winter	24	N-1	No constraint	4.5	Winter	-0.6	N-1	Winter	-11.5	-4.5	N-1	Security	4	Zone substation transformer	Network upgrade	Planning stage	Not applicable	The demand in the Frankton network area is growing and the Frankton substation demand forecast indicates that the load will be above the firm capacity. We plan to build two substations (Whakatipu and Jacks Point) to cater for localised growth areas in Frankton, Kelvin Heights and Jacks Point.
28	Queenstown	13	Winter	20	N-1 switched	No constraint	7.4	Winter	3.4	N-1	Winter	-3.3	1.9	N-1	Capacity	10+	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	The demand of the Queenstown subtransmission which supplies substations - Queenstown, Fernhill and Commonage is forecast to be above its firm capacity in RY31. We plan to upgrade the limiting sections of the subtransmission to increase its capacity and security by RY30-31.
	Remarkables	2	Winter	4	N	constraint	1.3	Winter	1.3	N	Winter	-0.5	1.3	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Berwick	2	Spring	3	N	constraint	1.2	Spring	1.2	N	Spring	1.1	1.1	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	East Taieri	18	Winter	23	N-1 switched	constraint	4.5	Winter	3	N-1 switched	Winter	0.8	2	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Green Island	14	Winter	18	N-1	constraint	4.5	Winter	9.6	N-1	Winter	5.2	9	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Halfway Bush	14	Winter	18	N-1	constraint	4.1	Winter	9.4	N-1	Winter	7.5	8.1	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Kaikorai Valley	11	Winter	23	N-1	constraint	12.3	Winter	11.8	N-1	Winter	11	11.5	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Mosgiel	7	Winter	12	N-1 switched	constraint	5	Winter	0.5	N-1	Winter	10.3	12.9	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	North East Valley	11	Winter	18	N-1	constraint	7.4	Winter	6.8	N-1	Winter	5.6	6.4	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Outram	3	Winter	8	N	constraint	4.6	Winter	4.4	N	Winter	4	4.2	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Port Chalmers	8	Winter	8	N-1	Security	-0.1	Winter	6.9	N-1	Winter	-1.5	-0.9	N-1	Security	1	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	The zone transformers are planned to be replaced with higher capacity in RY27-28.
	Smith Street	13	Winter	18	N-1	No constraint	5.4	Winter	2.5	N-1	Winter	1	1.8	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	The zone transformers are planned to be replaced with higher capacity in RY29-30.
	Ward Street	10	Winter	23	N-1	constraint	13.4	Winter	7.2	N-1	Winter	5.7	6.9	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Willowbank	13	Winter	18	N-1	constraint	5.1	Winter	4.7	N-1	Winter	3.9	4.3	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Andersons Bay	14	Winter	24	N-1	constraint	10.5	Winter	9.1	N-1	Winter	7.5	8.5	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Carisbrook	11	Winter	23	N-1	constraint	12.4	Winter	11.1	N-1	Winter	9	10.2	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Corstorphine	12	Winter	19	N-1	constraint	7.5	Winter	6.6	N-1	Winter	5.1	6.1	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	North City	15	Winter	28	N-1	constraint	13.2	Winter	11.8	N-1	Winter	11.2	11.7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	South City	15	Winter	18	N-1	constraint	3.5	Winter	5	N-1	Winter	1	1.7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	St Kilda	14	Winter	23	N-1	constraint	9	Winter	8.2	N-1	Winter	6.9	7.7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	

29 ¹ *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

Schedule 12c: Report on forecast network demand

Company Name	**Aurora Energy Limited**
AMP Planning Period	

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected during year by consumer type*	**Number of connections**					
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
11	*Consumer types defined by EDB**						
12	Residential	1,261	1,159	1,175	1,192	1,209	1,226
13	Load Group 0	3	5	6	6	6	6
14	Load Group 0A	(10)	3	9	12	14	15
	Load Group 1A	(14)	1	9	13	15	16
	Load Group 1	4	48	70	81	87	90
	Load Group 2	151	143	139	137	136	135
	Load Group 3	8	6	5	5	5	5
	Load Group 3A	3	3	3	3	3	3
	Load Group 4	6	5	4	4	4	4
15	Load Group 5	-	-	-	-	-	-
16	Street Lighting & DUML	-	-	-	-	-	-
17	**Connections total**	1,412	1,373	1,420	1,453	1,479	1,500
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	857	857	857	857	857	857
24	Capacity of distributed generation installed in year (MVA)	6	6	6	6	6	6
25	**12c(ii): System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**						
28	GXP demand	252	260	275	296	309	321
29	*plus* Distributed generation output at HV and above	60	60	60	60	60	60
30	**Maximum coincident system demand**	312	320	335	356	369	381
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	312	320	335	356	369	381
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	1,220	1,282	1,347	1,415	1,486	1,560
35	*less* Electricity exports to GXPs	43	43	43	43	43	43
36	*plus* Electricity supplied from distributed generation	379	385	391	398	404	410
37	*less* Net electricity supplied to (from) other EDBs	4	4	4	4	4	4
38	**Electricity entering system for supply to ICPs**	1,552	1,620	1,691	1,765	1,842	1,923
39	*less* Total energy delivered to ICPs	1,486	1,551	1,619	1,690	1,764	1,842
40	**Losses**	66	68	71	75	78	81
41							
42	**Load factor**	57%	58%	58%	57%	57%	58%
43	**Loss ratio**	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%

Schedule 12d: Report on forecast interruptions and duration

Company Name	**Aurora Energy Limited**
AMP Planning Period	
Network / Sub-network Name	**Total Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	210.0	155.0	158.2	148.0	145.0	153.6
12	Class C (unplanned interruptions on the network)	117.7	139.7	138.6	137.4	136.2	134.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.58	0.59	0.56	0.55	0.58
15	Class C (unplanned interruptions on the network)	1.64	1.93	1.91	1.90	1.88	1.86

Company Name	**Aurora Energy Limited**
AMP Planning Period	
Network / Sub-network Name	**Dunedin**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	128.2	116.1	87.5	100.6	92.2	120.7
12	Class C (unplanned interruptions on the network)	39.4	63.5	63.4	63.3	63.2	63.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.51	0.54	0.41	0.47	0.43	0.57
15	Class C (unplanned interruptions on the network)	0.58	0.94	0.93	0.93	0.93	0.93

Company Name	**Aurora Energy Limited**
AMP Planning Period	
Network / Sub-network Name	**Central Otago & Wanaka**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	279.8	221.4	279.2	250.0	213.2	187.6
12	Class C (unplanned interruptions on the network)	197.2	295.9	291.8	287.7	283.6	277.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.79	0.70	0.88	0.79	0.67	0.59
15	Class C (unplanned interruptions on the network)	3.59	3.95	3.90	3.84	3.79	3.71

Company Name	**Aurora Energy Limited**
AMP Planning Period	
Network / Sub-network Name	**Queenstown**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	184.6	177.9	279.0	148.4	273.8	213.5
12	Class C (unplanned interruptions on the network)	108.9	202.9	199.5	196.1	192.8	187.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.62	0.53	0.84	0.45	0.82	0.64
15	Class C (unplanned interruptions on the network)	2.35	2.91	2.86	2.81	2.76	2.69

Schedule 13: Report on asset management maturity

Company Name	**Aurora Energy Limited**
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Our Asset Management Policy is authorised by the Chair and CEO and published within our Controlled Document System. Our Asset Management Policy was reviewed, updated and Board approved in January 2024. It has an active role in informing the development of our SAMP and lower level asset management strategies. Greater communication of the AM Policy would further enhance understanding and line of sight in Asset Management		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	There are good linkages between the asset management strategy and other appropriate organisational policies and strategies such as the Business strategic priorities and our Risk Management framework but this is not yet comprehensive. Completion of our SAMP would further enhance the linkages (demonstrated in our AMP) between our Business Plan and our AM strategic objectives.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Lifecycle have produced our first Fleet Strategies (for critical fleets) in the past 12months. We have developed these documents to enable a decision making process at fleet/lifecycle level, that is guided by AM strategy, AM objectives and Organisational strategic priorities. We will build on the work done, make the strategies living documents - enable continuous improvement of lifecycle decision making and create Fleet Strategies for non-critical fleets.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Fleet Strategies have been documented for critical fleets. For asset systems (groups of assets) we are progressing towards optimising Opex and Capex activities at that system level, but are somewhat constrained and will be until we have enhanced Systems (IT) for managing data.		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).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	A significant amount of communication is undertaken digitally and in person during team meetings, one on one discussions and governance groups - AMCL October 2019. Additional governance practices, management processes, and external communication channels have been put in place since 2019.		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?	3	Processes documented within Promapp include roles and responsibilities. Internal position descriptions for our staff, and our contracts for outsourcing designate responsibilities for the delivery of our actions set out in our AMP		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	We have made significant improvement to our capability to deliver our asset management plan efficiently and effectively including a retenderof our field service agreements. Completing the implementation of our AMS software (Maximo) and our improved cost estimation practices will further lift our maturity.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Incident management and business continuity plan documents have been updated and revised since the last assessment. Emergency management and communication plans are regularly tested and any improvement opportunities are identified and addressed.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Management roles are in place to deliver the asset management strategy and policies. All roles have up to date position descriptions aligned to the delivery of asset management objectives.		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	Our resource planning process is informed by regular ELT review of business priorities and by processes to monitor and track our progress against agreed asset management improvement plans (e.g. CPP improvemnt plan) and the delivery of our annual work plan. We are largely meeting our asset management deadlines and we flex resources as required to stay on track. Staff departures from time to time require a continuous focus on recruitment. Further improvement requires a proactive (forward looking) planning approach.		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?	3	GM of Asset Management and Planning emphasises the need to meet asset management requirements, including the commitment to seek alignment with ISO 55000. There are regular team briefings and communication from top management to all relevant staff that refer to Asset Management Objectives and progress against them.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Process for Contract Management inplace and operational. Contractor selection process documented. Field Service Agreements are actively reviewed and ammended where appropriate. Alignment with asset management objectives and policies in development.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	Aurora Energy has an established organisational chart and roles to support the delivery of asset management. Critical roles in this area have been identified with succession planning underway. Aurora Energy has conducted a functional review to identify potential future roles which may be required to support asset management processes as part of strategic workforce planning processes.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	All Aurora Energy staff have development plans in place as well as regular training to ensure they are skilled and equipped in their respective roles.		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?	2	Competency registers are held for staff undertaking construction and Maintenance work. Training requirements for Asset Management staff are recorded in a Company register but a review system against competencies has 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	3	Regular engagemnt and information sharing occurs across the region through a multi-channel approach including publications, digital and in-person meetings and events. Asset management major projects are reported in the Annual Delivery Plan summary as well through the Aurora Energy Annual Report and comunity newsletter.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	We have a final draft of our Asset Management System Framework ready for final review and publication. We also have a considerable number of AMS documents in place and the main processes and the interactions between them have been documented in Promapp. A review of processes is required given the changes associated with Maximo etc.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Asset classifications have been developed for 12 Asset Fleet Categories as part of the asset managment system implementation. The high level design for asset data migration has been developed to migrate asset condition data from external sources to Maximo.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	The existing controls have been further enhanced by further quality reports in the last 12 months. The new controls ensure completeness and accuracy of the GIS matches that provided the enlivenings as effected when commisioning new assets by the Network Operations team. Ensuring the enlivened assets are updated and the ADMS and the GIS data sets are aligned.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The Asset managment system implementation is governed by a Steering Group made up of Executives representing all impacted stakeholders inside the business. This group meets regularly and ensures the implementation project delivers to plan.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	We have made progress - documenting failure modes for critical fleets, we are still using Safety Criticality Zones to prioritise work from a public safety perspective. Where this is not relevant (buried services) we have started to develop and apply reliability criticality. Within the Fleet Strategies, we have developed a framework, aligned with Corporate Risk Framework to assess other categories of risk, against each failure mode. Developing a tool that enables us to quantify risk across fleets is a priority.		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	New risks identified as part of incident investigations (ICAM) are added to the Corporate Risk Register. Regular reassessment of of the existing risk register occurs.		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	Aurora subscribes to ComplyWith and its companion tool ComplyWatch. ComplyWith enables Aurora to identify, understand, and report on legislative obligations that are relevant to the business. An annual survey is undertaken using the software to track compliance and identify necessary corrective actions. ComplyWatch enables Aurora to remain aware of legislative changes before they become enacted so that the business can proactively prepare for changing requirements.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	3	We have design and procurment processes and procedures in place for the delivery of our annual work plan. We are continuously improving these processes and procedures as we learn from incident reviews and implement our improvement initiatives such as Maximo, enhanced cost estimation and work quality assurance.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	We have completed a review of the Pole inspection programme and extended it to capture OH assets, including Conductors. We have also written a set of guidance docs and provided training to end users. We have more work to do across other Fleets Strategies to capture Maint activities required to manage known or emerging Failure Modes - each inspection plan will be reviewed against documented failure modes.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	We have established a Reliability Forum, and a process of reviewing asset failures, establishing Root Cause and taking the learnings to enhance and inform Maintenance activities. Fleet Strategies document failure modes, maint strategies are defined and assessed for gaps against failure modes - Inspection plan/questions will be reviewed against documented failure modes		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	Dedicated roles monitor network performance and carry out root cause analysis of outages. Asset failures are investigated by ICAM trained staff and the results reported to the wider business. The safety function has been decentralised, specific responsibilities are aligned based on critical risks and dedicated control owners.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformitie s	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	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	A number a major external reviews of our asset management systems and practises have been carried out including AMCL assessing against ISO55001. WSP-Opus, Sapere and Cosman Parkes have also reviewed safety aspects of our asset management practices. A routine internal audit system of our AMS is yet to be established. External audits of our Public Safety Management System occur on a periodic basis.		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?	2	Triggers set and understood for implementation of formal investigations of failures. Systematic instigation of actions stemming from ICAM is still immature and requires documenting to ensure consistency		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Our AMP includes an asset management development/improvement plan commensurate with our CPP reporting obligations. We are documenting change, and opportunities for improvements at a fleet level, in our Fleet Strategy documents. We have introduced a new Cost Estimation/Scoping Improvement project for Major Projects and we have developed templates for enhanced business case assessment of our network investments.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	We engage with industry/other EDBs re NEMA and introduction of new tech, we attend ENA/EEA workshops and global conferences (Distributech) and we work with suppliers and labs re RCA. We utilese the above and review EEA asset management guidelines and capture insights and learnings in our Future Network planning and our Fleet Strategy Documents. We engage consultants on specialised areas (e.g. pole lean/footing design). We are working to create an opportunity to learn more from our field crews. We are associated with Professional Organisations such as IAM, ENZ, EEA & ENA.		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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
Differences between constant and nominal forecasts are a direct output of our escalation approach. Our expenditure forecasts were determined in constant 2025 dollars and escalated to nominal dollars using forecast price indices. Each expenditure category is escalated separately using price indices specific to that category. Price indices for each expenditure category reflect a combination of labour and materials prices. Forecast labour and materials prices are obtained from a variety of sources.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

Appendix C: CPP Development Plan

As part of our CPP information disclosure requirements,[10] we have prepared a publicly available standalone Development Plan, which contains several business improvement initiatives. These initiatives are directed toward key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe improvements will bring genuine benefit to consumers.

The plan has been made publicly available to all consumers and other interested parties.

Aurora Energy's CPP Development Plan outlines our processes to improve our performance capability and includes the following key areas.

Asset Data Collection and Asset Data Quality

Accurate and reliable asset data is a prerequisite for effective asset management decision-making. Good quality data enables us to improve our budgeting, risk assessment, and forecasting abilities. To ensure we are meeting our business objectives and to optimise our future expenditure, Aurora Energy has an increasing need for reliable and comprehensive information. In particular, we require good-quality asset condition data to support timely spending decisions relating to asset renewals.

We have identified the following improvement initiatives that will enable us to develop and improve our asset data collection and data quality practices:

- Define and document key requirements for asset data to support decision-making, including master data and condition data
- Implement the systems and processes to facilitate the collection of asset data in a timely manner
- Implement the systems required to ensure robust storage and integration of our asset data
- Improve our internal data management practices by clarifying the roles of data owners and stewards
- Implement reporting tools and enhance our reporting practices

Asset Management Practices

Asset management capability forms a key area of improvement to ensure long-term efficient care of network assets. Further asset management development is required to continually meet consumers' expectations, manage network risks, and address changes in network demand and technology.

Public safety is a paramount objective for Aurora Energy, and it plays a fundamental role in our asset management decision-making. Many of our assets have an elevated safety risk in the event of failure, and many of our assets are also in close proximity to public areas.

Part of our asset management improvement involves refining our risk framework to better understand the likelihood of particular assets failing and to identify the potential outcomes of such failures. Our key initiatives include further development of our modelling to understand asset health and criticality. Refined health modelling will help us better identify the likelihood of asset failure and implement appropriate preventive measures.

Criticality helps us understand the potential consequences of asset failure so we can introduce appropriate controls. With regard to consequence of failures, we have already established Safety Criticality Zones in our GIS. We have used these safety zones to guide our pole replacement programme, wherein we prioritised replacements in areas of high traffic or public density such as main roads, schools, and tertiary institutions.

During the CPP Period, we will develop failure modes, effects and criticality analysis (FMECA) across all asset fleets to support a standardised approach to managing asset risks across different areas, including Safety,

[10] See Electricity Distribution Information Disclosure (Aurora Energy Limited) Amendment Determination 2021, available here.

Reliability, Environment, and High Impact Low Probability (HILP) events.

As part of our CPP disclosure requirements we have produced a publicly-available Safety Delivery Plan, which demonstrates how we have used our improved safety risk assessment to report and track our safety risk reduction over the CPP Period. We aim to refine our risk management framework further so that we can optimise our investment in renewals to replace assets with the greatest impact on safety. Further, we will continue to develop alternative methods of control such as design standards and maintenance programmes as cost-effective alternatives to replacement.

We also plan to introduce fleet strategies/plans which define our decision-making processes for each asset type based on their risk profiles. The individual fleet strategies will be guided by an overall Strategic Asset Management Plan (SAMP), which will govern asset management activity to align with our overall business objectives.

Cost Estimation Practices

Improved cost estimation practices can help the business identify and deliver upon cost-effective solutions for network improvement. The plan will cover both capital and operational expenditure projects and programmes.

Areas of development include the following initiatives:

Enhanced unit rate estimation: We will enhance our processes for capturing as-built costs. We will also establish an annual unit rate review process to ensure our budgets and forecasts are informed by the most up-to-date market rates.

Enhanced project cost estimation tool: For zone substation growth and renewal projects and other large projects we will enhance our cost estimation tool.

Improvements to our network opex models: We will improve the data that informs our 'Base-Step-Trend' forecasting models.

Review the vegetation forecasting model: Improved vegetation status data and input costs for vegetation-related works (e.g. customer liaison and second-cut costs) will enable us to develop a more comprehensive model for forecasting vegetation management costs.

Quality Assurance Processes

The purpose of Aurora Energy's quality assurance processes is to ensure capital expenditure and operational expenditure programmes are effectively delivered to meet applicable industry standards. Appropriate quality assurance processes and resources must be in place to ensure the escalated level of planned works during the CPP Period are delivered to all applicable standards.

In our approach to improving quality assurance, we plan to implement two separate focus areas: works management capability and construction works quality assurance. Within works management, we are introducing robust frameworks to identify and monitor quality risks during key project stages. We have rolled out continuous staff development in alignment with the PRINCE2 methodology to drive efficient delivery of capital and maintenance projects. We also aim to roll out improvements to processes and systems to enable better reporting, risk monitoring, and visualisation of project health, leading to more successful delivery.

We aim to improve our works quality assurance by introducing internal standards and quality assurance metrics that guide the review of constructed works. We also plan to extend the scope of our quality assurance review process to include inspection and maintenance tasks, connection services, and zone substation works. We will review the required resourcing and internal development to meet the requirements of our upgraded quality assurance process.

Appendix D: Development Initiatives Tracker

Note: Line items with a light blue background are initiatives planned for RY26.

Voltage Quality

Phase/Initiatives	Progress update for AMP25
Reacting to Monitoring	
Monitoring to Anticipating	
DTM Program and Field Work	72 DTM installations progressing and will be completed before RY26.
Hosting capacity study	
Network scenarios	
Hotspot modelling	HV Powerflow modelling to identify hotspots is complete. The DG hosting capacity of the whole low voltage network was completed by ANSA last December, completing the overall initiative using meter consumption data. This provides information on which locations in the LV network are, or will be, constrained, and where investment will be needed to resolve constraints. Given the unexpected high cost and long contract duration associated in the procurement of smart meter network operating data (NOD), we decided to conduct business cases for procurement, including an LV visibility platform, to better understand and inform our investment decision to move forward.
Anticipating to Predicting	
Refine scenarios	
Predictive modelling	HV Powerflow modelling to identify current hotspots is complete and the same model can be used to model the impact of growth scenarios on the HV network. The DG hosting capacity of the whole low voltage network was completed by ANSA last December. This provides information on which locations in the LV network are, or will be, constrained, and where investment will be needed to resolve constraints. The LV visibility platform will provide proactive and additional PQ use cases. As mentioned above, the investment is higher than expected (especially the smart meter NOD data), hence the need for a business case for both the platform and NOD to ensure that progress of forward benefits will be captured.
Standards and strategies	A measurable plan needs to be developed as standards; Strategies and material lists are ongoing.
Preventive solutions	Work will start on this once we have completed the updated DG hosting and LV Visibility project.

Customer Engagement

Phase/Initiatives	Progress update for AMP25
Initial review, consultation and launch of revised customer charter and compensation arrangement	The new Customer Charter was launched on 20 August 2024. Reporting processes are in place and will involve regular internal reporting and annual public reporting.
Increase knowledge of, and commitment to, our customer charter and compensation arrangement	The new Customer Charter was launched on 20 August 2024 and is now being promoted regularly to the public via our print and online channels, in direct mail to customers as part of Aurora Energy's community relations programme, and at events. It is promoted internally via posters in all offices and in our reception area at our head office in Dunedin. A video is currently being produced, which will be used both externally and during staff inductions. There is a question in the annual customer satisfaction survey about awareness of the Customer Charter so we will be able to measure changes year on year. Annual reporting will be both public and internal.
Promote and celebrate Aurora Energy's commitment to customer experience	This project was delayed due to workload but is now progressing and it is expected to be rolled out within the next year.
Conduct a further review of the customer charter and compensation arrangement to ensure it remains fit for purpose and is well understood	

Quality Assurance

Phase/Initiatives	Progress update for AMP25
Develop and implement process improvements	Recently completed Leva report will help us refine and fine tune our current processes. Need to refresh some current documentation and information.
Continuous staff development	Continuing to train and upskill staff in Prince2; performed training for traffic management. Safety observations being performed by the team, extending their health & safety and construction knowledge. Non-electrical people do ES2 as well.
Develop construction works review standard	Completed
Extend scope of construction works reviews	Completed
Incorporate quality assurance metrics into wider contractor performance metrics	Completed
Review resourcing	Completed
Staff training and development improvements	Completed

Management of Planned Interruptions

Phase/Initiatives	Progress update for AMP25
Bundled works	
Increased use of bundled works	Completed
Develop reliability zones	Completed
Use reliability zones in high voltage outage planning	Completed
Use reliability zones in high and low voltage outage planning	Reliability zones do not currently include LV. The focus has changed, using an LV visibility platform as a better approach. Asset Management is progressing LV visibility platform to a closed RFP process.
Stage gate process	
Develop stage gate process	Completed
Implement stage gate process	Completed
Outage variations	
Adopt cancellation and deferral policy	Completed
Develop outage variation reporting framework	Completed
Implement outage variation corrective action process	Completed
Mitigating impact of planned interruptions	
Review outage planning guidelines	Completed
Implement outage planning guidelines	Completed
Outage management system	
Implement new outage management system	Completed
Provide real time planned interruption status via the website	Completed
Provide real time planned interruption status via subscriber SMS	Project planning is underway. This project has been delayed due to workload but will progress during RY25.

Asset Data Collection and Asset Data Quality

Phase/Initiatives	Progress update for AMP25
Asset data requirements	
Define and document key asset and network-related data requirements	Completed
Define and document business rules to support decision making	Completed
Asset data collection	
Automated systems for collecting data from contractors	Integration with our three FSPs (Field Service Providers) is progressing well. A detailed design for the FSP integration has been undertaken. The Core Systems Team, with external and internal support, is working directly with each of our three FSPs to work through the integration requirements and timelines for launch. We have exchanged testing messages through our integration pipe with ElectroNet and are working with them to test three simple work package scenarios (an inspection and two asset replacements). In August we also started to undertake these tests with Delta and Unison. Starting in October, Aurora Energy will start releasing capex Asset Replacement and Renewal (ARR) via the integration to ElectroNet, followed by Unison and Delta two months later. We have successfully sent work orders for Asset Replacement & Renewal and Admin to all five main contractors via the FSP integration, and also recently obtained the first completion activities in Maximo for data coming back. Next on the plan are the CIW portal integration, inspection and maintenance forms, and other opex activities.
Improve data storage	
Implementation of an Asset Management Software Solution	Integration of Maximo with SAP (our financial management system). SAP purchasing and goods receipting integration has been unit tested and system integration testing and user acceptance testing commenced mid-July. Once we have completed user acceptance testing for the SAP integration, we will look to run some training sessions with end users. Invitations will be sent once testing is complete. This integration is expected to be leveraged in the production system from September.
Development and implementation of a data integration hub	Completed
Build data management framework	
Bringing a range of policies, standards and processes in place to ensure availability and integrity	Completed
Improve the ways in which we clean up our data	Rollout has happened for two business units so far; two others have been scheduled. Focus is on regulatory data and personal data.
Implement data management controls	Completed
Implementing data audits	Completed

Asset Management Practices

Phase/Initiatives	Progress update for AMP25
Strategy and Planning	
Strategic Asset Management Plan (SAMP)	Asset Management Framework (AMF) initial draft completed for review. Our SAMP will be guided by our Asset Management Policy and will outline how our asset management objectives support the delivery of our business strategic objectives and initiatives. In 2024, we commenced work on our SAMP; however, this work has been paused in favour of other business priorities. Work has commenced on development of some supporting asset management strategies, including spares, reliability, and vegetation. These will be complete in 2025.
Fleet Strategies and Plans	These documents will be guided by our asset management objectives and define our decision-making and implementation frameworks for each asset fleet. We have fleet strategies/plans for all major fleets. We are currently in the process of working with a consultant on an independent review of the fleet strategies/plans.
Asset Information	As part of our asset data collection and quality development plan we defined the asset attributes needed to inform our maintenance and renewal strategies. We have completed a review and documented new inspection standards for all of our overhead assets, distribution transformers, distribution switchgear, and low voltage enclosures. This work ensure we have access to the asset information we need. As the maturity of our risk-based asset management decision-making improves, we will continue to refine the specification of requirements for asset data attributes, including installation and location information as well as condition data for lifecycle management, enabling data capture in our technology systems, GIS and Maximo (our AMSS).
Asset Failure Modes	We have documented plausible failure modes for all major fleets and are currently in the process of completing a plan for the remaining fleets. We have also introduced a feedback loop for our root cause analysis to capture new or emerging failure modes. When writing or reviewing our inspection standards, we ensure that we have addressed all detectable failure modes.
Define and Evaluate Risk	
Asset Health	As our asset information improves, we are incorporating asset condition into our assessment of overall asset health. Within our fleet strategies we have a model for each fleet that informs our overall assessment of asset health. These models are maturing with enhanced asset information and enhanced asset management practices, and are reviewed annually. Continuous improvement amendments are documented.
Asset Criticality	We will register criticality factors in our information systems and incorporate them in our calculation of an asset criticality index for each affected asset. We have a defined safety criticality zoning framework, which enables us to prioritise work on safety critical assets, across all fleets. We have progressed the application of reliability criticality indices for zone substation assets only. We are currently in the process of documenting our Reliability Strategy, which will inform our plan and will include formalising a general approach to reliability criticality framework.
Risk Evaluation	We are putting foundational blocks in place to enable fit-for-purpose risk evaluation. As part of documenting failure modes in our fleet strategies, we have assessed the impact of failure against all corporate risk categories. In the context of our safety-driven CPP plan, our focus has been on maturing data critical to informing safety risk, while applying public safety criticality zones to ensure effective prioritisation across fleets. As we prepare to transition from CPP to DPP4 we will bring reliability and resilience risk into focus, alongside a continued focus on safety. As stated above, the next key milestone is the Reliability Strategy, which is due for completion in 2025.
Asset Management Decision Making	
Align decision making with risk	Using improved asset condition data; well-defined fleet strategies; and documented plausible failure modes informing asset inspection and maintenance; and supported by a robust understanding of failures on the network through our newly established root cause analysis, we are aligning our investment plans to ensure they are risk-informed and prioritised. We are capturing in our fleet strategies what actions target specific failure modes and causes – including all new or emerging failure modes related to materials and workmanship causes.
Define and monitor risk control effectiveness	Over the past 18 months we have stood up a forum to track, investigate, and follow up on asset failures. The learnings from our investigations sometimes point to a need to address workmanship or materials shortcomings. By understanding the root causes of failures, we are able to assess the effectiveness of controls, such as inspections, and make the necessary enhancements when new information comes to light.

Phase/Initiatives	Progress update for AMP25
Define and document investment approval process	A new business case template and manual have been developed using the Better Business Case methodology. The new business case template can be used for both network and non-network projects, and will be tested for suitability using the current projects. We will document the process of evaluation and approval of major projects, programmes, and minor works within the described risk framework. Work in progress is the adoption of an economic analysis calculator with customer lens.
Risk Management and Review	
Review our critical business risks	Completed
Risk treatment plan and ownership	Completed
Governance Reporting	Completed

Cost Estimation Practices

Phase/Initiatives	Progress update for AMP25
Enhanced unit rate estimation	
Improved management of unit rates	To ensure units rates are reviewed and modified in a robust way we will introduce a more comprehensive system and process for managing/updating our unit rates and their application to our budgets and forecasts. Enhancements are expected to include change control management, historical tracking of rates, the addition of known future price increases and integration links with our project cost estimation tool.
Volumetric project scope breakdowns	Completed
Major project cost breakdowns	Tender documents contain the necessary detail breakdown but only a small number of reference projects involving cost variances, so it is difficult to draw unit rate conclusions at this stage. Ownership of spreadsheet and process to be determined.
Establish contract unit rates	Our new Field Services Agreements contain an enhanced set of unit rates agreed with our service providers (when compared to the previous agreements). Using our primary service provider as an example, there are over 50 unit rates for maintenance and defect activities. We are currently discussing the next tranche of unit rates with field service providers.
Improve project cost estimation tool	In 2023, we undertook an initiative to enhance our cost estimation processes and robustness. With a focus on major projects, the scope of this work included definition of detail required for project scoping at various stage gates as a project came into focus in the plan. Our master unit rate book was reviewed. Further enhancement has been identified to enable continual improvement in the alignment between estimating rates and those that represent a competitive market rate. We will extend the development of customised estimates to include additional programmes of work such as distribution reinforcement projects and conductor renewal projects.
Including a broader range of projects	We will extend the development of customised estimates to include additional programmes of work such as distribution reinforcement projects and conductor renewal projects.
Informed 'Base' expenditure	Completed
'Step' expenditure review	Completed
Review our 'Trend' assumptions	Completed
Capture vegetation programme information in our systems	We have made progress with developing mechanisms, including systems to ensure we have access to quality data on vegetation management. Greater transparency of our vegetation cost drivers will enable enhanced forecasting. We have also commenced follow-up investigations for vegetation-related faults, enabling us to check the effectiveness or otherwise of our investment priorities.
Develop a 'Base Step Trend' or 'bottom-up' forecast model	We propose to develop a new forecasting model for vegetation taking into account new data and information. This is currently based on a base step trend model, with work underway to enable a condition- or risk-based approach to vegetation management.

Note on initiatives and timeframes

Reprioritising in the context of changing business needs, maturing asset management practices and constrained resourcing has had an impact on our ability to meet some targeted milestones as defined in our CPP Asset Management Development Plan.

Appendix E: Reliability Management

Reliability management involves meeting the ongoing regulatory requirements set for us by the Commerce Commission. These requirements involve performance targets and limits set for both planned outages (scheduled repairs and replacements) and for unplanned outages (power cuts).

Our performance is measured against SAIDI and SAIFI, metrics that indicate the frequency and duration of outages for an average customer over a year. We are measured against an assessed version of SAIDI/SAIFI rather than the raw total for all events during the year. For planned outages we receive a discounted value for correctly notifying customers, while for unplanned outages the impacts of major event days are reduced.

During the CPP Period, Aurora Energy has been setting individual limits and targets to account for our deteriorating performance in previous years. Similar to other EDBs, we are set financial rewards/penalties based on our performance against these target values. If we exceed the limit values in any year, we potentially face further consequences.

Table 17-1 gives a description of all terms discussed with regard to reliability.

Table 17-1: Reliability management terms used

Term	Description
SAIDI	SAIDI (System Average Interruption Duration Index) represents the average number of minutes of power outages that an average consumer has experienced over a year.
SAIFI	SAIFI (System Average Interruption Frequency Index) represents the average number of power outages that an average consumer has experienced over a year.
Planned outage	These outages are for scheduled work on our network such as asset replacements, maintenance, new consumer installations, and tree felling.
Unplanned outage	These outages refer to unscheduled power cuts such as network faults or emergency repairs.
MED	MED (Major Event Day) events are events that have a significant impact on the network within a short timeframe. Because these events are typically driven by uncontrollable factors such as extreme weather, the SAIDI/SAIFI impact is assessed at a lower value.
Assessed SAIDI/SAIFI	This is the annual SAIDI/SAIFI minus any discounted values.
Regulatory limit	This is the maximum SAIDI/SAIFI value that an EDB is allowed. These values are assessed annually for unplanned outages and over five years for planned.
Regulatory target	This is the target SAIDI/SAIFI values that an EDB should achieve. We receive financial penalties for going above target and rewards for going below.

Planned performance

For all planned outages, we ensure that consumers are notified through their retailer and that information is available from our updated website.

While planned outages are inconvenient, we see them as an overall benefit to consumers. Unplanned outages generally have greater impact, and our current work programmes will reduce the frequency of this type of outage over the long term.

Over the planning period, we have forecast a slight reduction in planned SAIDI and SAIFI. We have undertaken extensive work in recent years to improve our network, and we expect fewer replacements will be required in the coming years.

Table 17-2: Planned vs unplanned outages

Planned Outages	Unplanned Outages
Customers are notified prior to the outage	Occur without any prior warning
Scheduled to avoid inconvenience for customers where possible	Can occur at any time of day
The network can be reconfigured ahead of time to limit the number of customers affected	Can affect wider areas before our crews are able to reach site and reconfigure the network
Scheduled at a specific location with all resources and crews prepared	Outage durations are often longer as crews need to locate the fault, identify the repairs required, and mobilise the required resources

Unplanned performance

For our unplanned performance, we have also forecast some improvement over the planning period, and we expect to remain safely within the current regulatory limits. Over the coming years, we aim to address performance issues in localised areas of our network. While this approach may have limited benefits in terms of overall SAIDI and SAIFI, we feel it is important to address the needs of our worst-served customers.

Reliability performance by sub-network

The figures below outline historical and forecast performance across our three sub-networks in terms of unplanned SAIDI and SAIFI.

Figure 17-1: Unplanned SAIDI - Dunedin

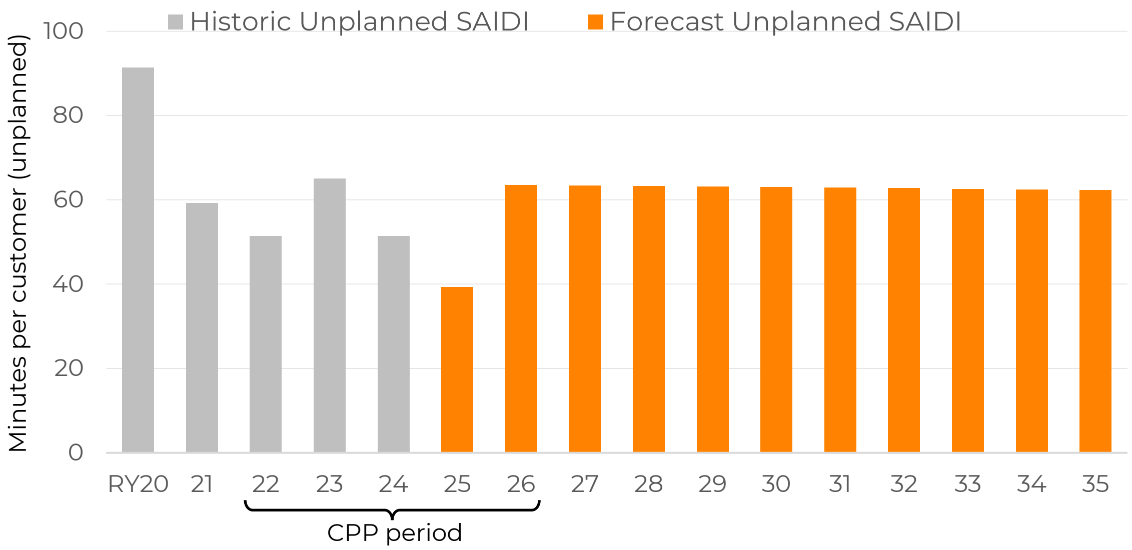


Figure 17-2: Unplanned SAIDI - Central Otago & Wānaka

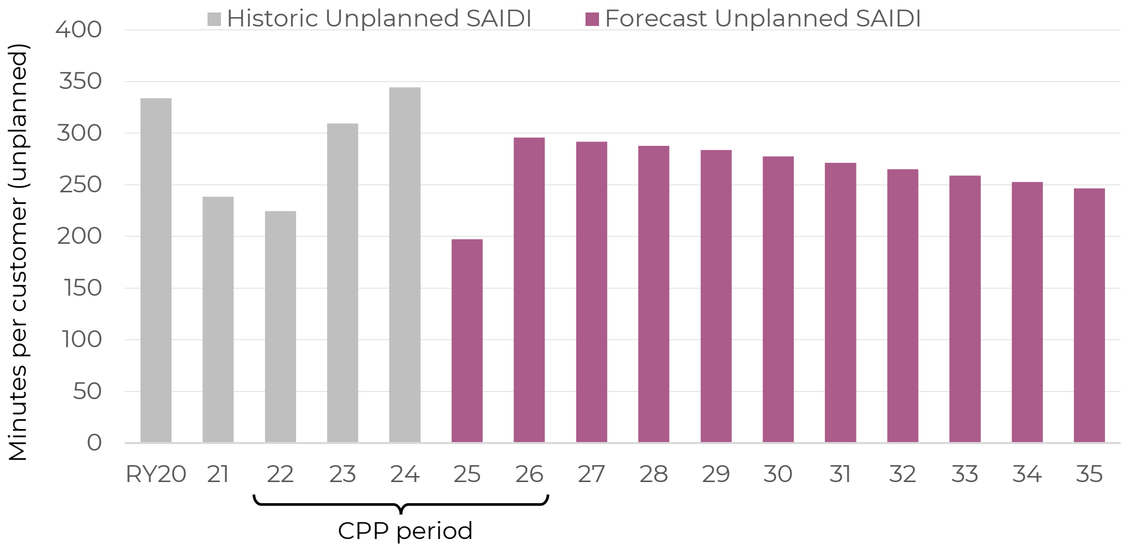
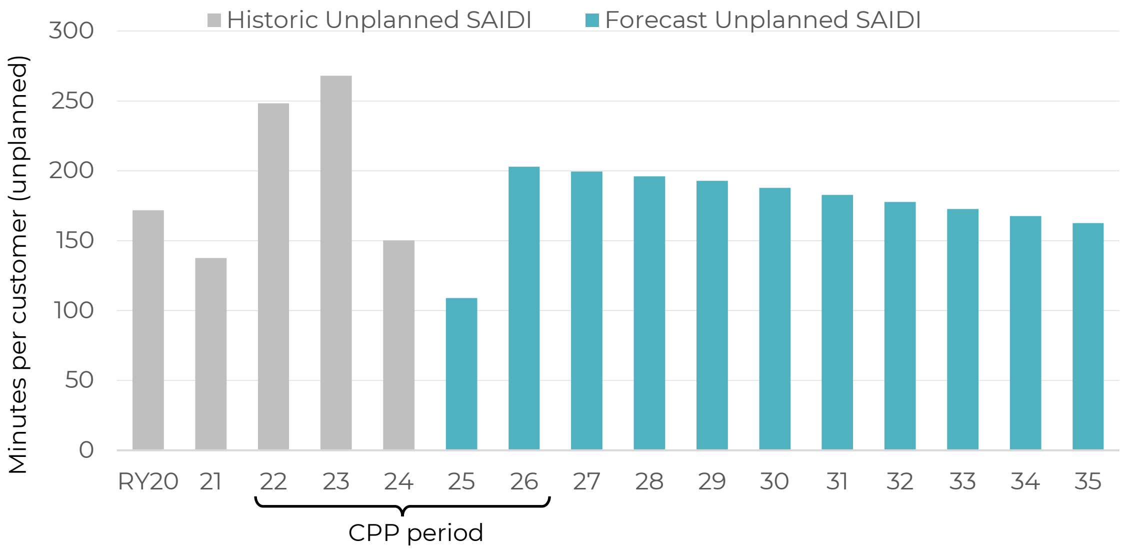


Figure 17-3: Unplanned SAIDI - Queenstown



Overall, the Dunedin sub-network performs at a high level of reliability, with the average consumer experiencing only a single unplanned outage on an annual basis.

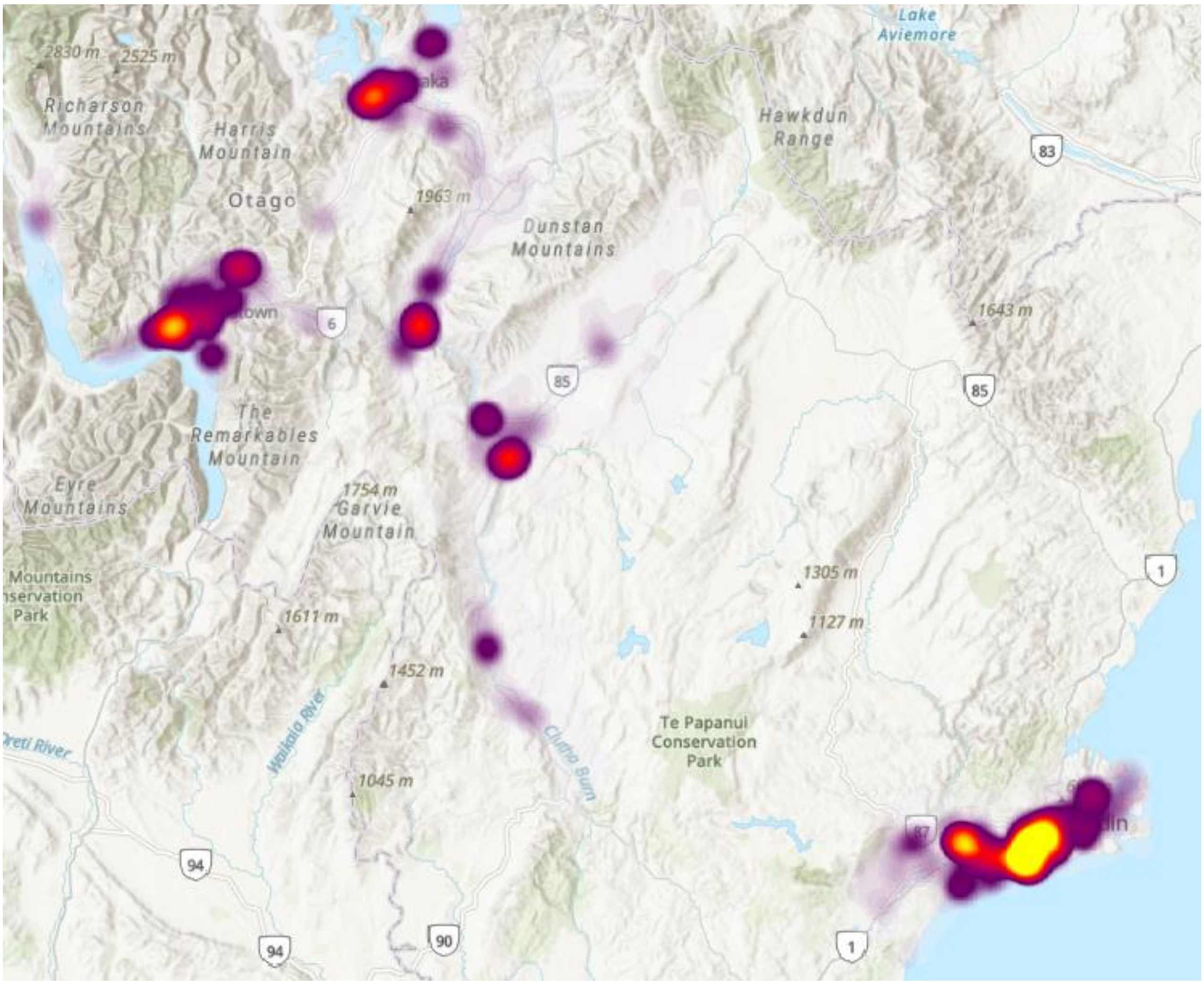
Consumers in our other sub-networks tend to experience a greater number of outages overall, particularly in recent years. Our forecast indicates that we expect to see some improvement in these areas over time. It is important to note that several factors influence reliability at a regional level, so it is not feasible for all consumers to expect the same level of performance.

The key regional differences are summarised in Table 17-3 and Figure 17-4.

Table 17-3: Regional factors influencing reliability

Reliability Factor	Urban vs. Rural
Customer density	Urban areas generally have high customer densities, often hundreds per network kilometre. In contrast, rural areas have as few as one to five customers per kilometre.
Circuit lengths	Rural circuits can often run tens of kilometres to connect customers to a supply point. In urban areas, customers tend to be within range of multiple supply points, so we typically install several shorter circuits in these areas.
Fault frequency	As circuit length increases, more assets are required to connect customers to a supply point, and there is greater exposure to other factors such as vegetation, wildlife, lightning strikes, and vehicle damage. In general, the longer the circuit, the more likely it is to experience faults.
Alternative supply options	In urban areas, circuits are connected in a grid-like pattern. In the event of a circuit failure, we can often restore supply to some customers from alternate circuits. In rural areas, supply areas are often too far apart to be interconnected.
Undergrounding	Underground networks are generally more reliable as they are not subject to external factors such as weather and vegetation. Undergrounding is also many times more expensive than overhead lines, so it is only cost-effective in cases where we can install a small amount of cable to supply many customers.

Figure 17-4: Heatmap indicating customer densities across our network



Although there are several challenges that affect reliability performance within rural areas, we still aim to deliver a certain level of performance for all our consumers. Our key focus over the coming years is to ensure consumers in our worst performing areas receive a better level of service. Given the focus on select network areas, a targeted approach will not necessarily translate into significant improvements in our overall unplanned SAIDI and SAIFI performance. However, overall, we believe that it is important to deliver a consumer-focused approach to reliability rather than prioritising our regulatory requirements.

Reliability hotspots

In 2022 we introduced our reliability hotspots initiative, in which we identified our worst-performing circuits across the network. We have since reviewed the performance of these circuits and developed tactical planned expenditure which will address known performance issues. We have communicated with affected customers to acknowledge the poor performance in their area and outline our upcoming planned expenditure.

During 2024, we have continued to improve upon our approach to the reliability hotspots, with key changes that are currently being implemented.

Table 17-4: Reliability hotspot improvement opportunities

Improvement Opportunity	Benefit to Hotspot Feeders
Ongoing review vs. annual review	Our initial approach was to identify 10 feeders each year for review and follow-up action. We have observed that feeder performance can deteriorate quickly over days and weeks, so we have transitioned toward weekly monitoring. We also noted that feeder performance issues were often resolved before the annual review was performed, with the result that no further action was needed. We see this change as an opportunity to proactively manage local performance issues. As part of our newly-established Customer and Reliability Leadership Group, we have monthly reporting around network performance, including quarterly and annual reviews. This group will help us identify and manage longer-term feeder performance issues.
Revised selection criteria	Our initial approach ranked poor performing feeders across a wide range of criteria to avoid favouring specific areas. Results were not often updated due to the additional work required to perform calculations. Our updated approach applies standard criteria to identify feeders that experience multiple faults in a set time period as 'circuits of interest'. Once flagged, each feeder then undergoes further review to determine whether to treat it as a hotspot.
Targeted actions	Our ability to differentiate hotpot feeders from circuits of interest will help us identify appropriate follow-up actions. **Circuit of Interest** – depending on the nature of the outages, follow-up inspections or other short-term solutions may be utilised. Ongoing monitoring is performed in case further issues occur. **Hotspot Feeder** – once a feeder is escalated to a hotspot, a targeted engineering solution is required. This approach will involve detailed review of feeder performance and engagement with the wider business to identify practical solutions.
Localised performance focus	Some of our rural feeders cover a wide area, such as OM656, which has a circuit length over 200 km. Typically, we have treated OM656 as a hotspot feeder, although the majority of issues may lie in a specific area. Going forward, we are monitoring feeder sections separately to identify circuits of interest.

Appendix F: Growth Project Details

The following tables set out our main planned major network development projects for the AMP planning period.

Table 17-5: Dunedin Subtransmission Ring Configuration

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Dunedin Subtransmission Ring Configuration	Replacement of ageing subtransmission cables feeding Dunedin CBD substations gives opportunity to review configuration	• Replace as-is with dual circuits to each substation • Change configuration to a ring network	**Change configuration to a ring network** This solution provides the following benefits: • Avoids the risk associated with dual cables in a shared trench • Significantly improves the transfer capacity between HWB and SDN GXPs		
			Smith Street to Willowbank	2024–25	5.6
			Smith Street to South City	2031–33	3.6
			South City to Ward Street	2031–33	2.8
			South City to Carisbrook	2031–33	6.5
			North City to Ward Street	2033–35	3.6

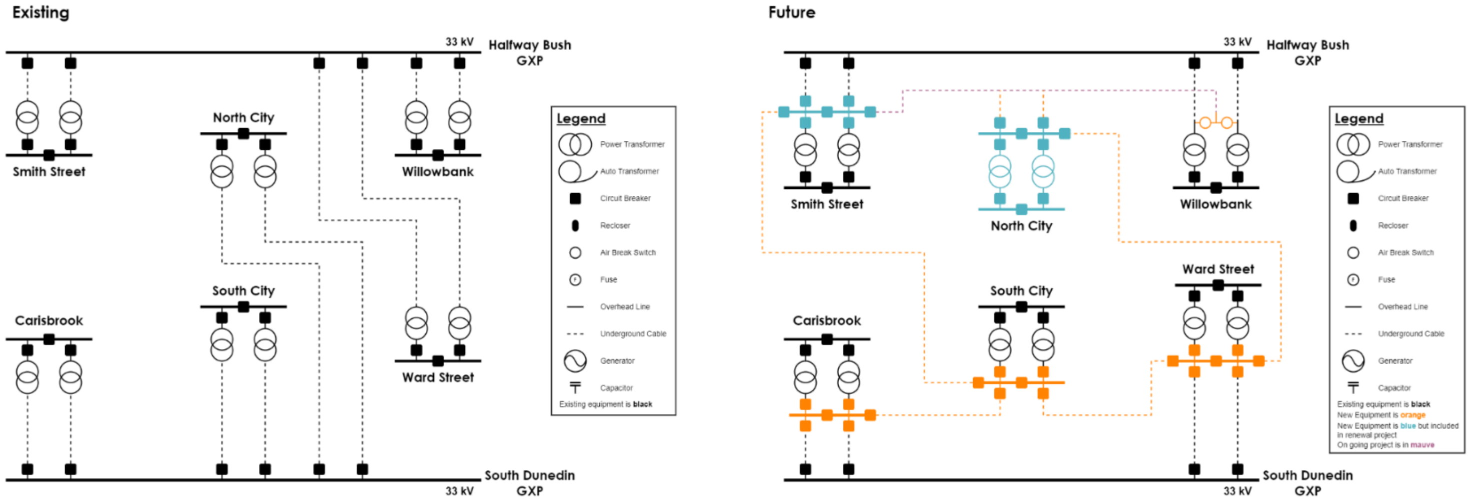
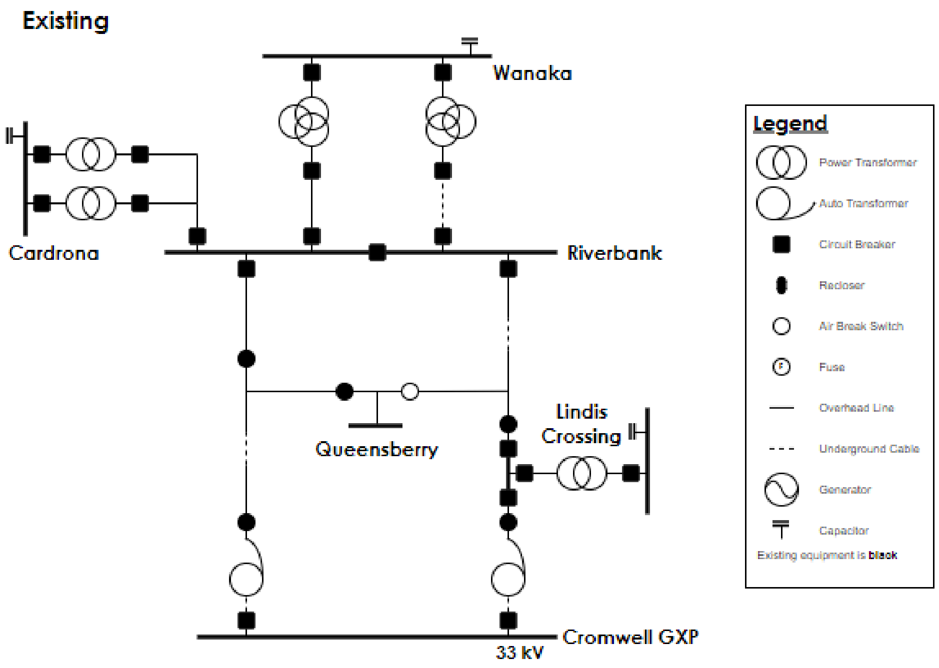


Table 17-6: Riverbank zone substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Riverbank New zone substation	Demand at Wānaka substation is above the N-1 firm capacity.	• Install new zone transformer with higher capacity • Install a third zone transformer at Wānaka substation • Build a new substation at a new location • Install a zone transformer at Riverbank Switching Station	**Install a 24 MVA transformer at Riverbank Switching Station** This solution provides the following benefits: • Offloads Wānaka substation • The switching station has adequate space for one or two zone transformer which reduces cost and delivery time. • Projected demand growth can be accommodated with additional capacity and increase in security. • Provides transfer capacity between substations.	2025–27	3.8



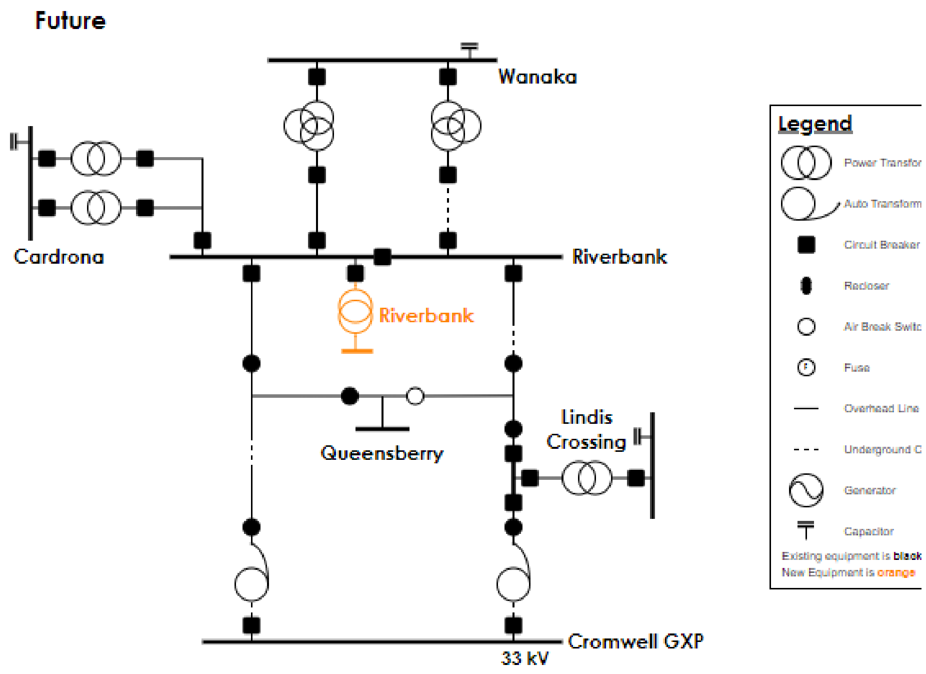
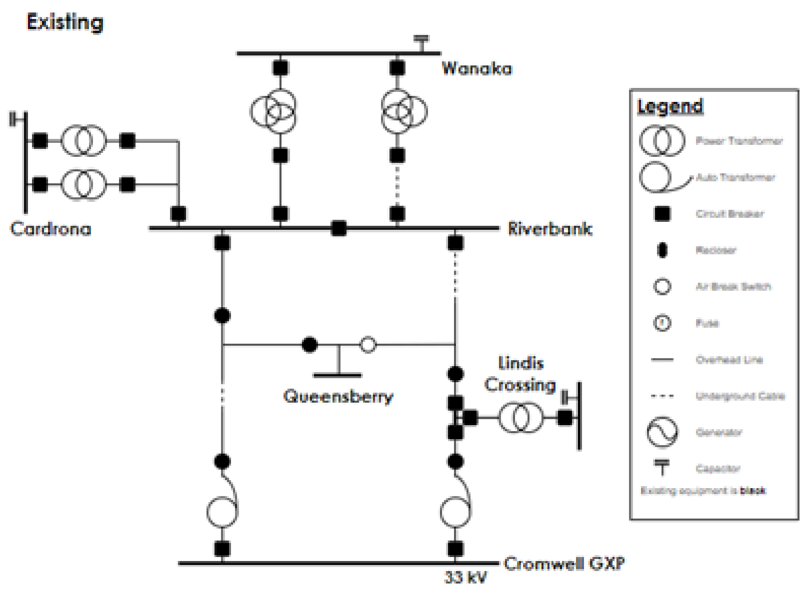


Table 17-7: New Queensberry Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
New Queensberry Substation	Queensberry substation is a single transformer substation. The demand is >70% and is forecast to exceed the transformer capacity. The adjacent Lindis Crossing substation (also a single transformer) does not have enough capacity to absorb additional demand from Queensberry substation.	• Install a larger size transformer • Rebuild Queensberry substation on new site with 66 kV bus, larger transformer and mobile substation bay	**Rebuild Queensberry substation on new site with 66 kV bus, larger transformer and mobile substation bay** This solution provides the following benefits: • Additional capacity with a larger size transformer. • The existing site has limited space, with continued growth, the new site with adequate footprint can house another transformer. • Opportunity to rationalise the 66 kV line connection with a close bus and that will improve voltage and minimise protection issues. • Increases transfer capacity to Lindis Crossing substation. • Build the new substation to the current standard.	2025–28	8.5



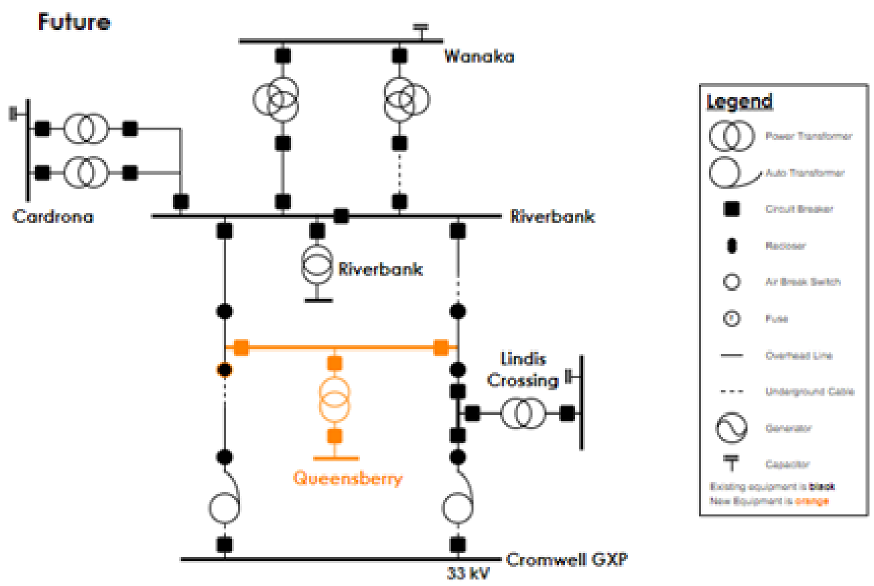


Table 17-8: Upper Clutha Capacity Upgrade

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Upper Clutha Capacity Upgrade	The Upper Clutha region is experiencing unprecedented growth. Forecast indicates that the growth will continue towards 2050.	• New 66 kV line from CML GXP to Upper Clutha route 1 • New 66 kV line from CML GXP to Upper Clutha route 2 • New Capacity injection	No solution has been identified at this stage. We are still undergoing cost benefit analysis of the shortlisted options. The cost indicated is an estimate from one of the options.	2027–31	65

Table 17-9: Luggate zone substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Luggate zone substation	Demand in the Luggate area is growing, and proposed large developments will require capacity injection in the area	• Construct a new substation at Luggate with mobile substation bay • Construct additional feeders from Riverbank substation • Construct additional feeders from Queensberry substation	**Construct a new substation at Luggate with mobile substation bay** This solution provides the following benefits: • Increases the substation capacity in the Queensberry - Luggate area • Provides some backup to the single transformer Queensberry substation • Improves distribution voltages by providing substation capacity at the Luggate load point	2029–31	7.5

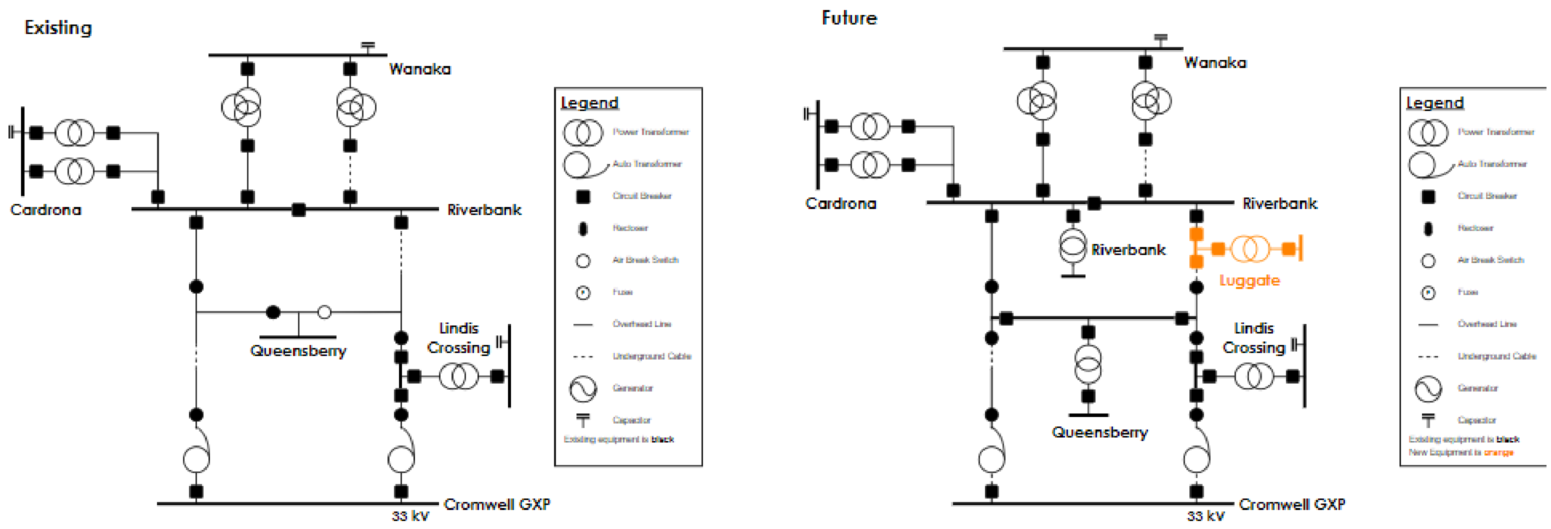


Table 17-10: Cardrona-Riverbank 66 kV New Line

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Cardrona-Riverbank 66 kV New Line	The demand growth of the Cardrona substation will require increase in security level.	• Construct new 66 kV line • Construct new 11 kV feeder from Wānaka	**Construct a new Cardrona-Riverbank 66 kV line** This solution provides the following benefits: • Increases the security and reliability of supply to the Cardrona Substation • Comply with Aurora Energy's Security of Supply Guidelines	2033–35	12

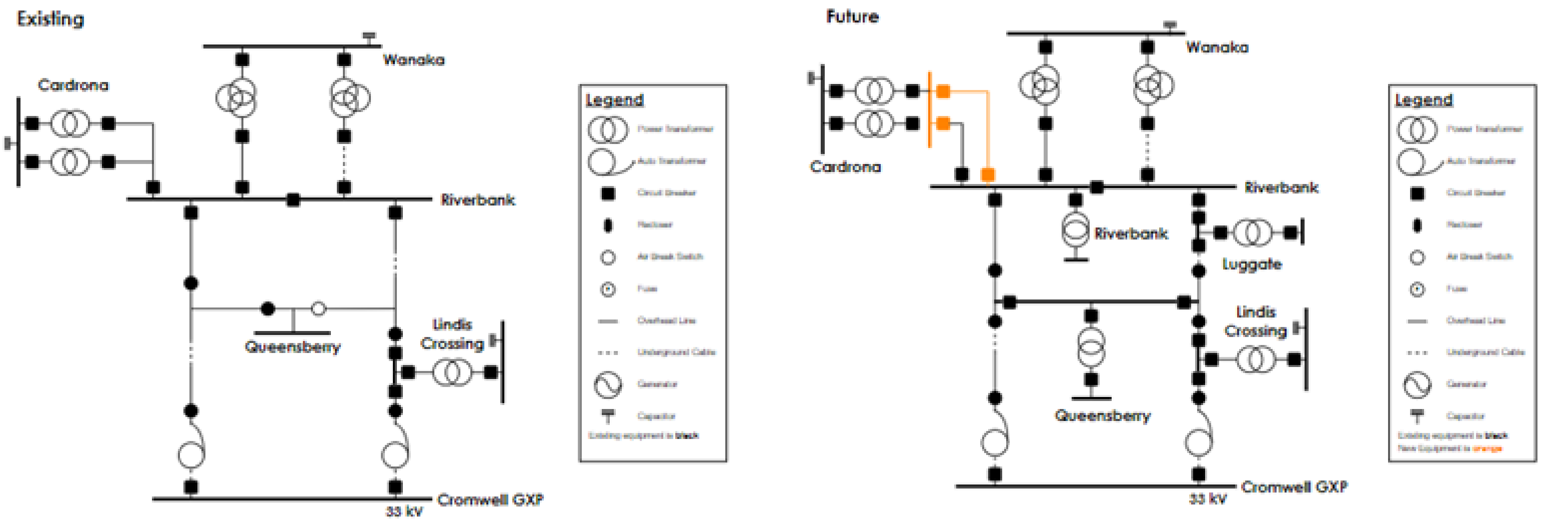


Table 17-11: Lindis Crossing Capacity Upgrade Stage 1

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Lindis Crossing Capacity Upgrade Stage 1	Lindis Crossing substation is a single transformer substation. The demand in RY25 is 84% of the transformer capacity and forecast to increase further to >90%. The adjacent substation has very limited transfer capacity.	• Do Nothing • Install a new 24 MVA transformer and extend 11 kV switchgear at Lindis Crossing zone substation • As above, with 6 MVA transformer (ex-Cardrona)	**Install new 24 MVA transformer and extend 11 kV switchgear at Lindis Crossing zone substation** This solution provides the following benefits: • Provides capacity to cater for load growth, particularly irrigation and fruit packhouses • Provides ability to backfeed Queensberry zone substation, which has only one transformer • Provides additional 11 kV feeders into Bendigo area, thereby reducing load on existing feeders and enabling better backfeed for planned and unplanned outages	2033–34	4.7

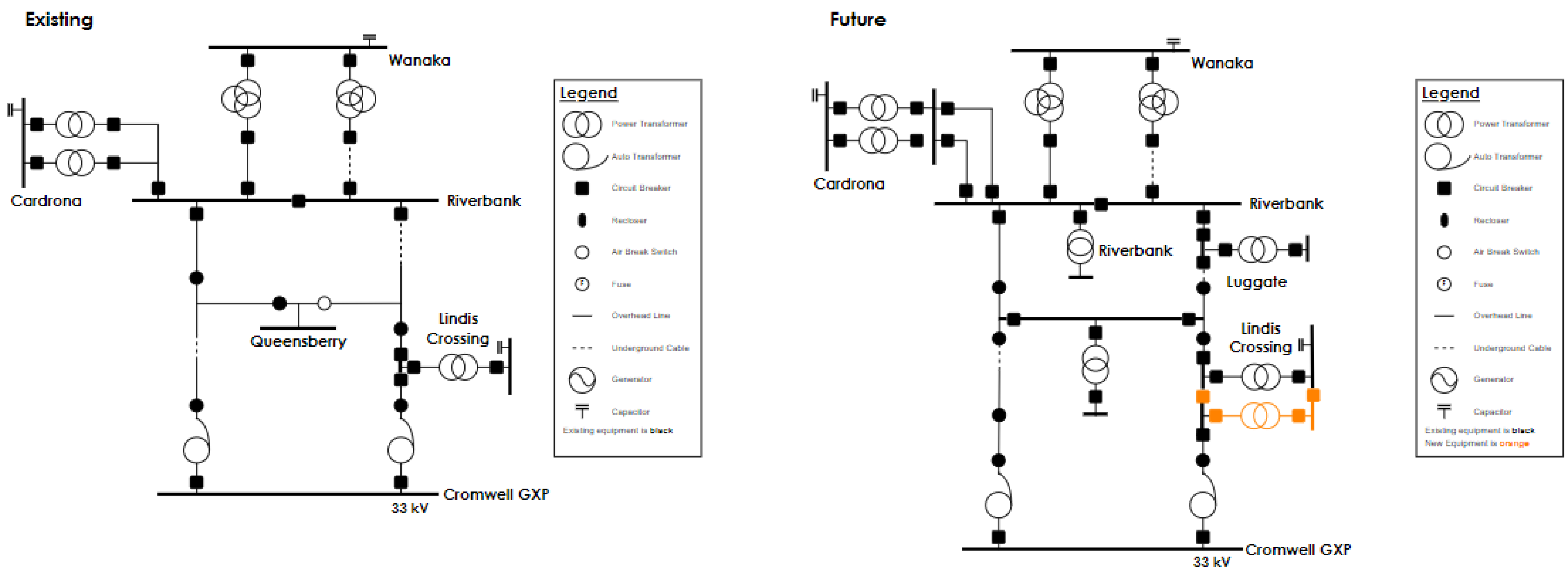
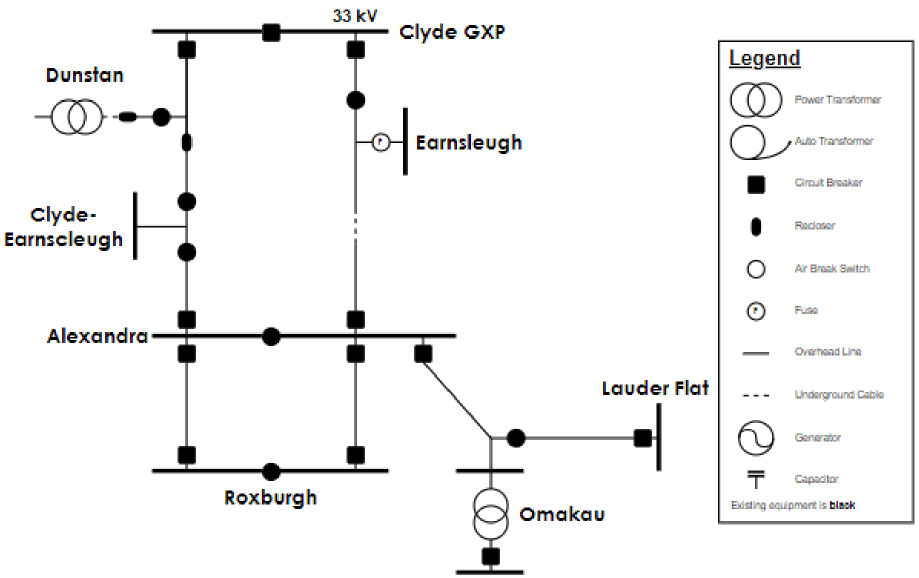


Table 17-12: New Omakau Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Omakau New zone substation	The load of the single power transformer substation has reached its capacity It has limited backfeed from adjacent substations and does not have a mobile substation bay. These limit the offload options during maintenance and unplanned outages The substation is located on a road reserve with no space to expand The substation has a flood risk being located very close to the river	• Offload to Lauder Flat zone substation with mobile substation bay • As above, without mobile substation parking bay • New zone substation with mobile substation parking bay • As above, includes strengthening 11 kV interties	**New zone substation with mobile substation bay** This solution provides the following benefits: • Improves the reliability of supply to Omakau zone substation • Significantly increases the capacity of Omakau zone substation enabling us to meet projected future growth in electricity load • Reduces the risk of equipment failure due to replacement of equipment that is at or close to end-of-life • Build the new substation to the current standard	2021–25	3.1

Existing



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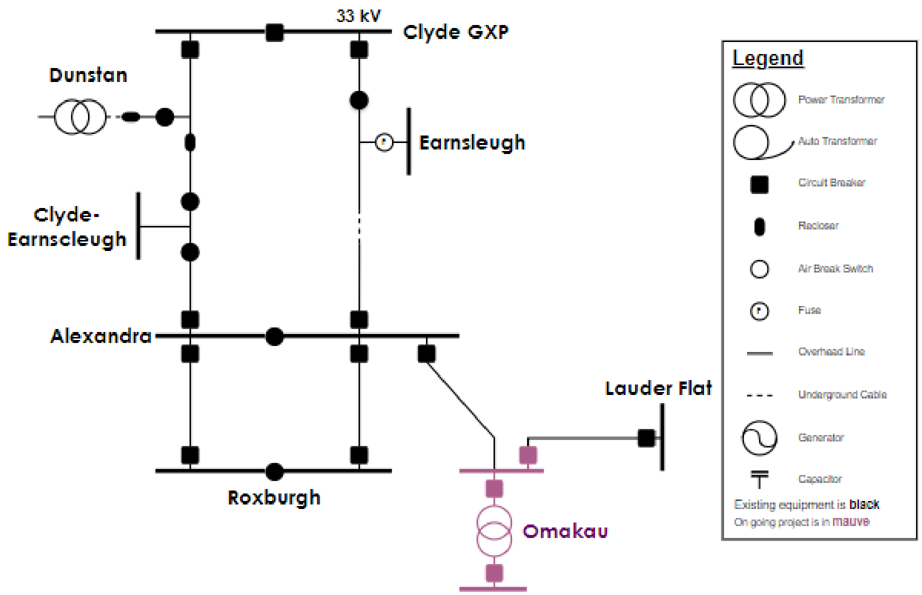
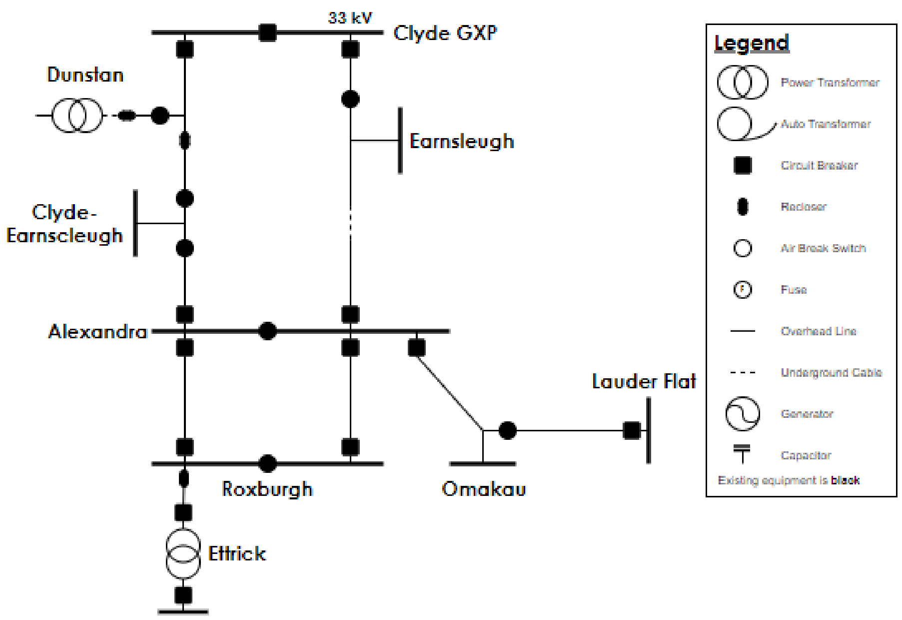


Table 17-13: Dunstan Stage 2

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Dunstan Stage 2	Due to the aging assets, Clyde/Earnscleugh substation (CE) will be replaced by Dunstan substation. Further, increasing irrigation load will exceed the capacity of this substation	• Rebuild substation on existing site • Rebuild substation on new site • Feed from existing new Dunstan Substation	**Feed from existing new Dunstan Substation** This solution provides the following benefits: • Provides significantly increased capacity. • Makes use of otherwise "stranded" asset	2026–27	2.2

Existing



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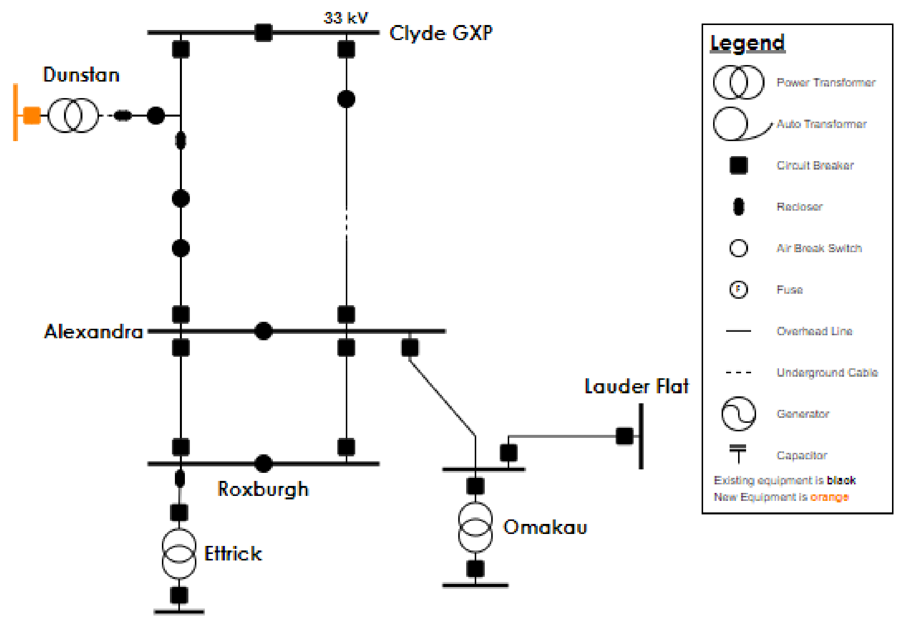
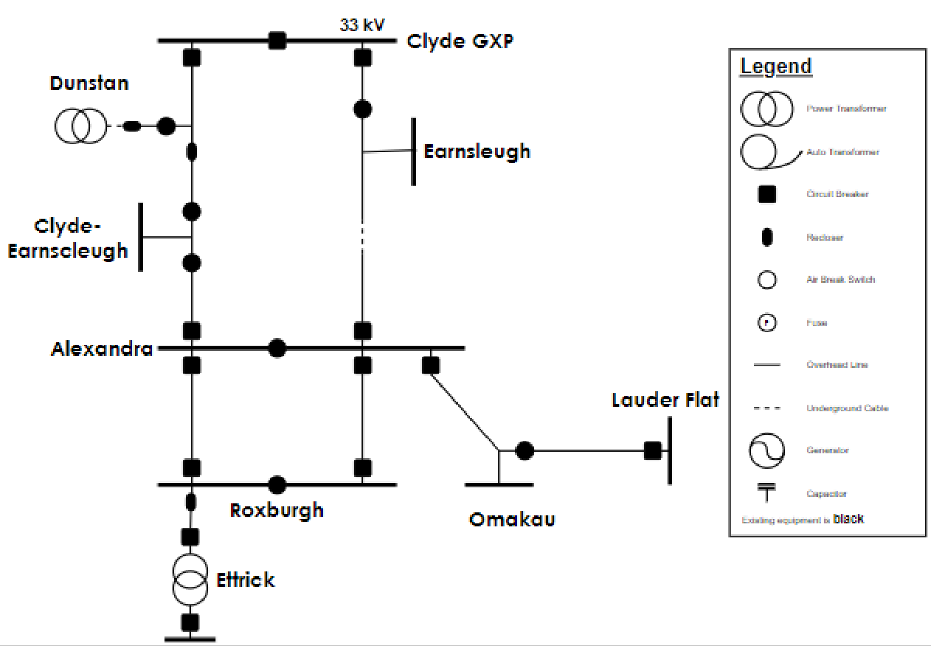


Table 17-14: Alexandra-Omakau New Subtransmission Line Stage 1

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Alexandra-Omakau Subtransmission Line Stage 1	The growing irrigation load in the Omakau-Lauder Flat area is exceeding the thermal capacity of the existing Alexandra-Omakau 33 kV line The first half of the existing line is mostly Squirrel, the second half is Ferret	• Upgrade all squirrel and ferret conductors on the existing line • Upgrade only squirrel conductors on the existing line • Construct a second Alexandra-Omakau 33 kV line	**Upgrade only squirrel conductors on the existing line** This solution provides the following benefits: • Resolves the immediate thermal constraint and Increases subtransmission capacity to meet growing load • Economical solution by replacing the squirrel conductors only • Allows for future upgrade of the remaining line when required	2028–30	3.3

Existing



Future

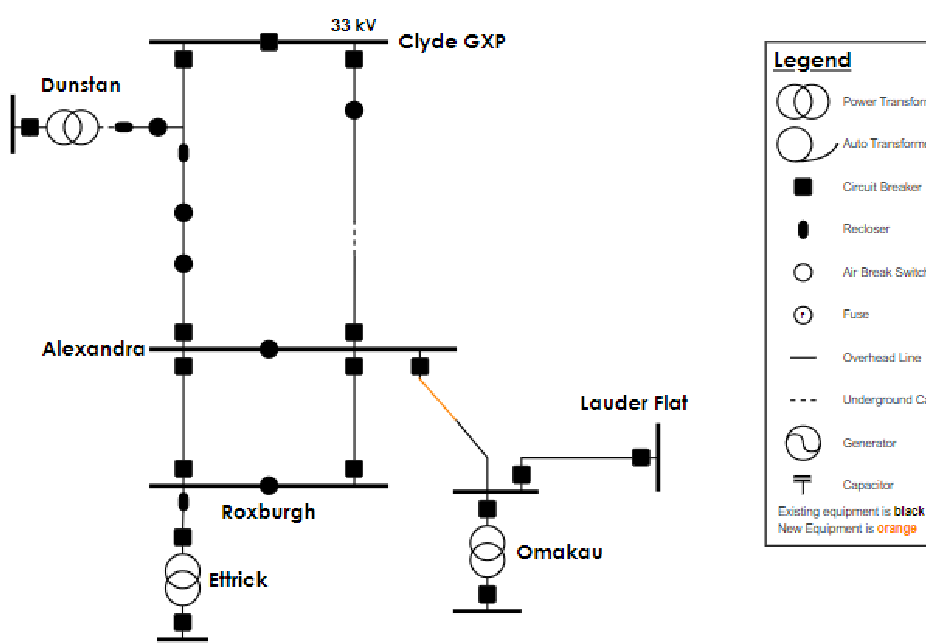
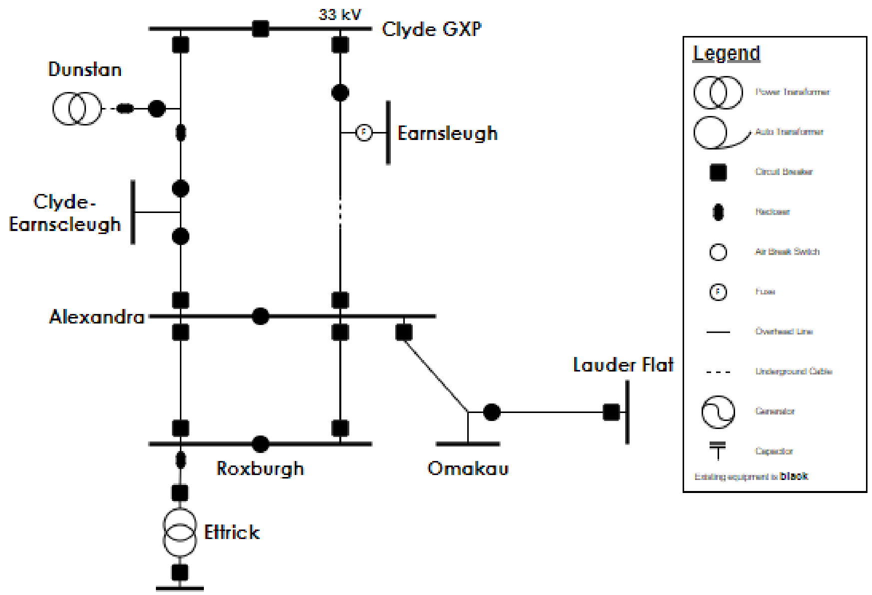


Table 17-15: Ettrick zone substation Upgrade

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Ettrick zone substation Upgrade	Ettrick Substation is too small to provide backup to Roxburgh	• Do nothing • Install larger transformer as part of rebuild project and increase distribution feeders	**Install larger transformer as part of rebuild project and increase distribution feeders** This solution provides the following benefits: • Allows Ettrick to back up Roxburgh Substation • Creates for larger number of feeders for Ettrick to allow improved distribution network performance • Build the new substation to the current standard	2031–33	6.1

Existing



Future

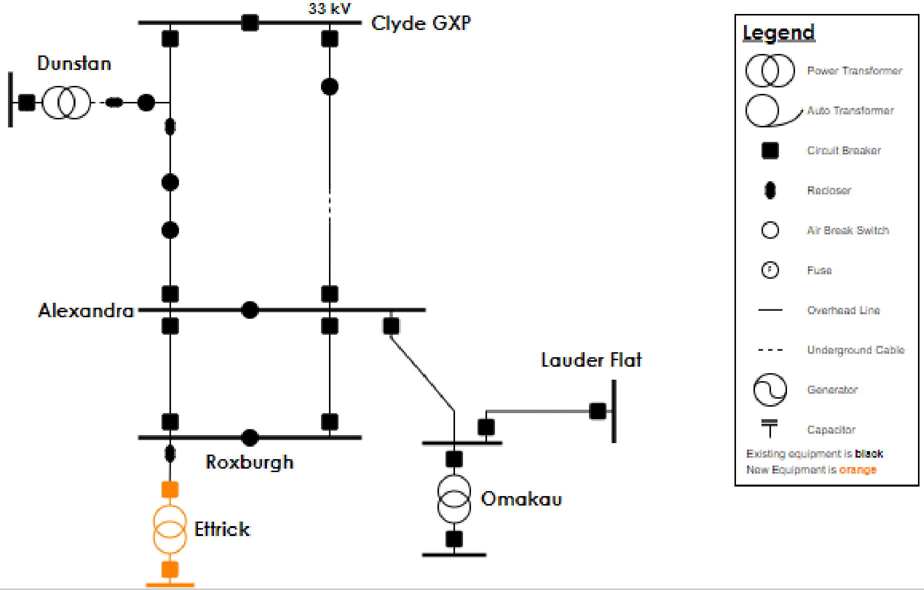


Table 17-16: Malaghans Substation (New Dalefield)

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Malaghans Substation (New Dalefield)	Dalefield, Arthurs Point, Speargrass Flat, Lake Hayes, and Arrowtown areas are experiencing significant demand growth. With the demand growth, there is a need to increase the security level and capacity of Dalefield zone substation.	• Renew Dalefield Zone substation on existing site and renew Arrowtown, and Coronet Peak substations • Renew Dalefield zone substation on new site to pick up load of Dalefield, Coronet Peak and part of Arrowtown and Frankton load.	**New zone substation to replace Dalefield and Coronet Peak and transfer some Arrowtown and Frankton load** This solution provides the following benefits: • Provides increased security and capacity • Removes two small "N" substations for which it was difficult to provide backup • Reduces the load on Arrowtown substation and hence allows the Arrowtown rebuild to be delayed • Provides a 33 kV bus to allow the new 33 kV cable to be run closed with the overhead line	2025–28	11.2

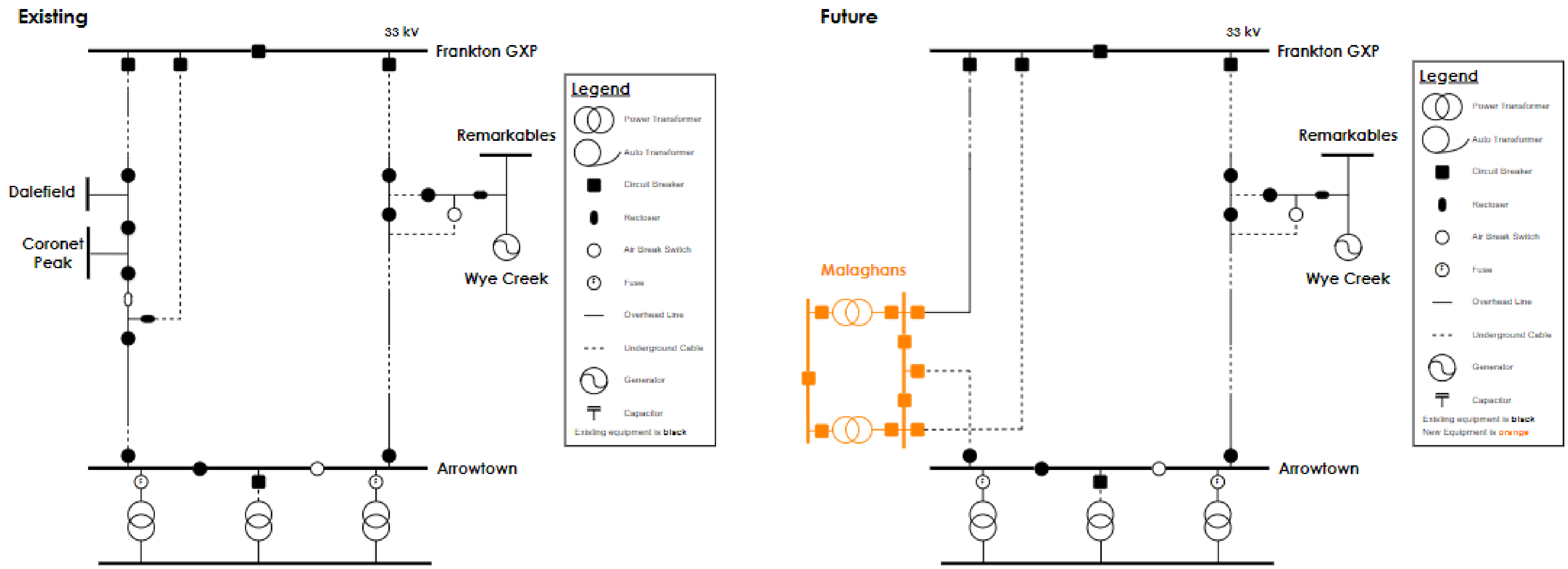
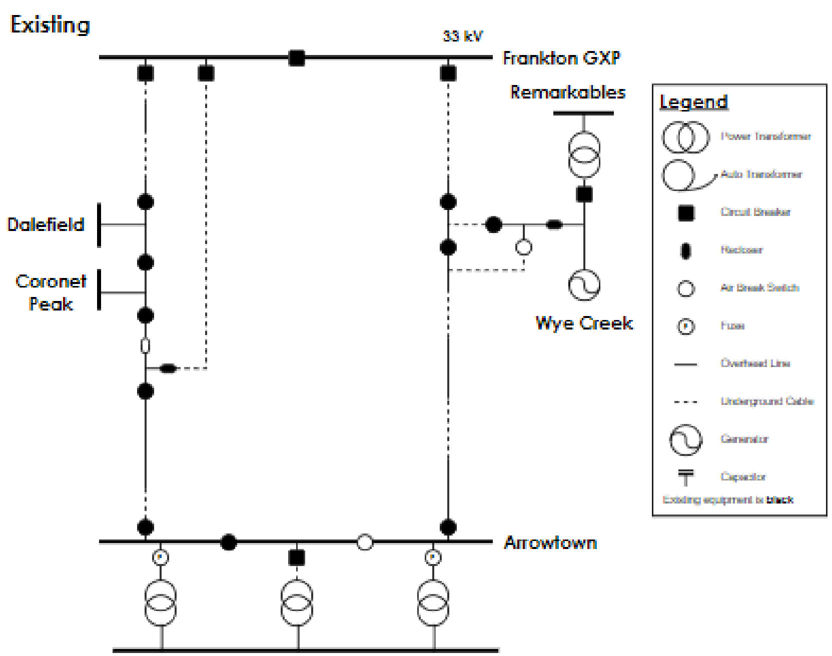


Table 17-17: New Remarkables Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
New Remarkable Substation	Increasing localised demand growth	• Do Nothing • Replace existing zone transformer with higher capacity • Rebuild substation with higher capacity transformer and more distribution feeders	**Rebuild substation with higher capacity transformer and more distribution feeders** This solution provides the following benefits: • Provides increased capacity to support localised growth • Provides for larger number of feeders to allow improved distribution network performance • With larger number of feeders, new interconnection with adjacent substations can be made	2029–30	6



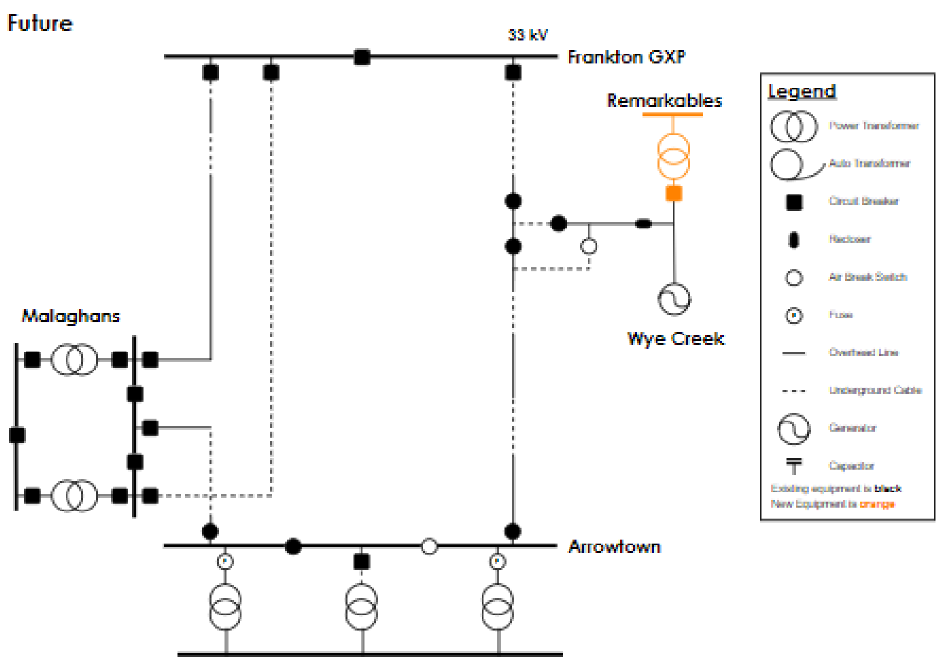
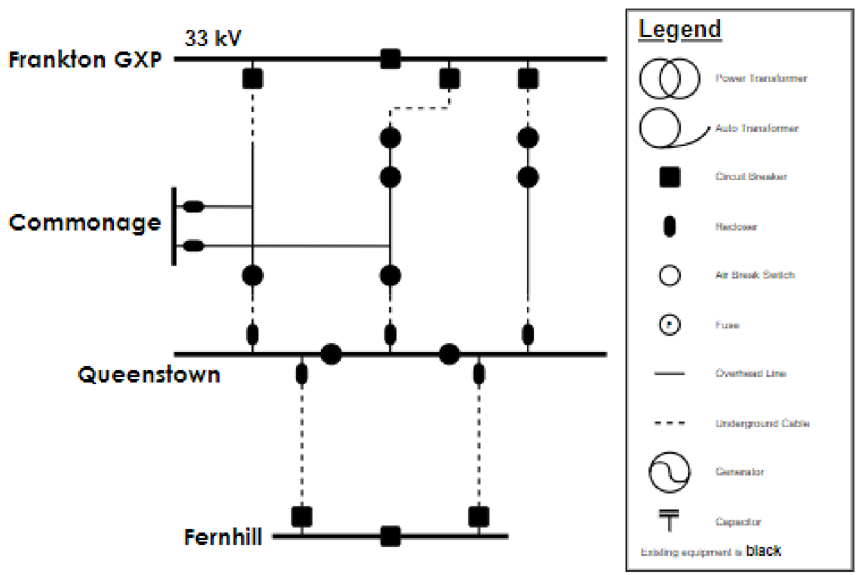


Table 17-18: Queenstown Subtransmission Capacity Upgrade

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Queenstown Subtransmission Capacity Upgrade	Load Growth is expected to exceed the firm thermal capacity of the subtransmission conductor from Frankton GXP to Commonage substation	• Thermally uprate existing conductor • Replace existing conductor • Add a new circuit	**Replace Existing Conductor from Frankton GXP to the Commonage Tee** This solution provides the following benefits: • Increases firm transmission capacity to meet the growing load • Reduction in voltage drop and losses	2030–31	2.5

Existing



Future

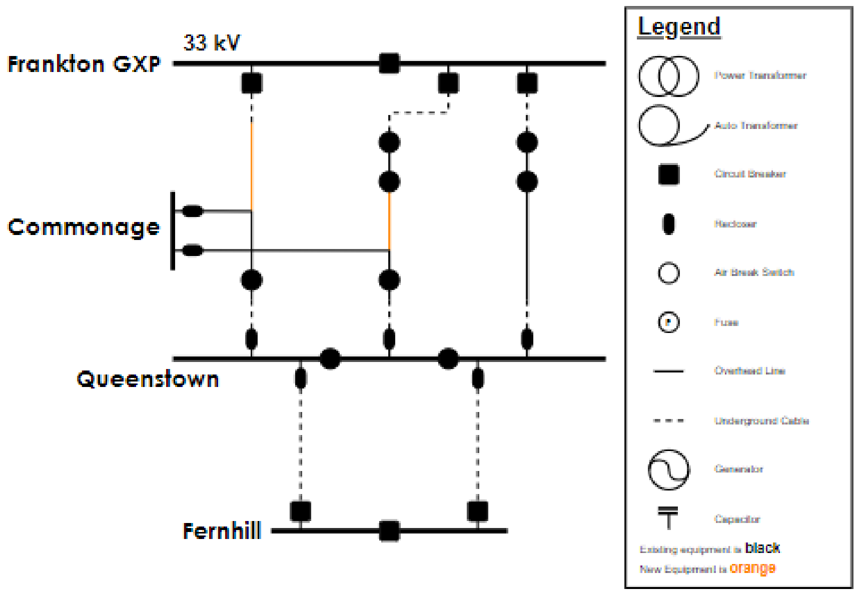
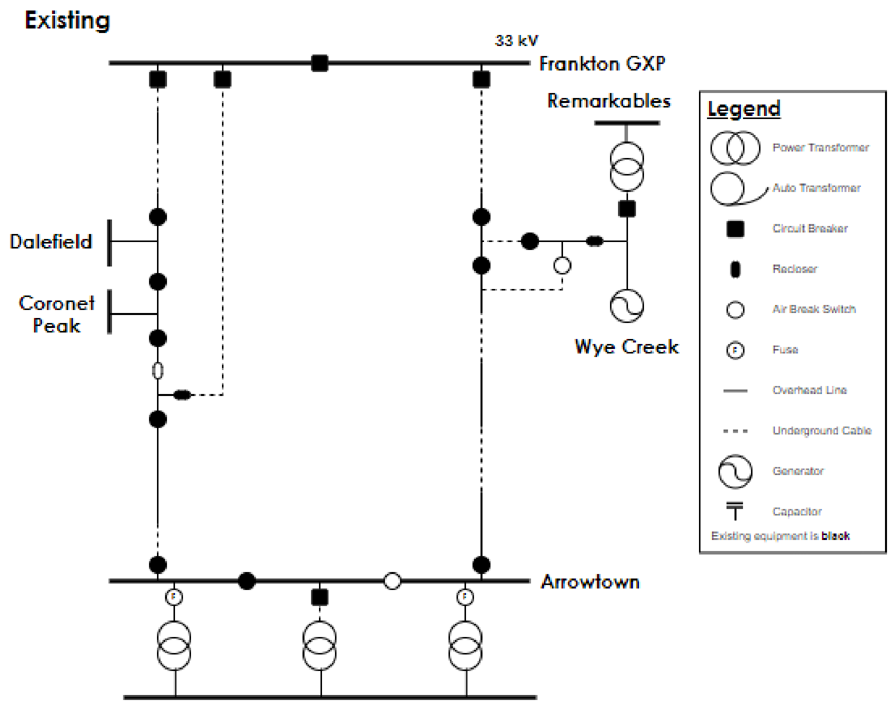


Table 17-19: Jacks Point Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Jacks Point Substation	There is strong demand growth in Frankton South, and this impacts the Frankton Substation capacity. The area is currently fed by a single distribution feeder from the said substation.	• Do nothing • Build a new substation with single transformer and mobile substation bay • Increase capacity of Frankton substation and install a new feeder to Frankton South	**Build a new substation and mobile substation bay** This solution provides the following benefits: • Existing substation site reduces the substation build cost • Offloads Frankton substation • Provides capacity to Frankton South • Rationalise the distribution feeder to improve reliability • Opportunity to create backfeed to Frankton substation	2030–31	5



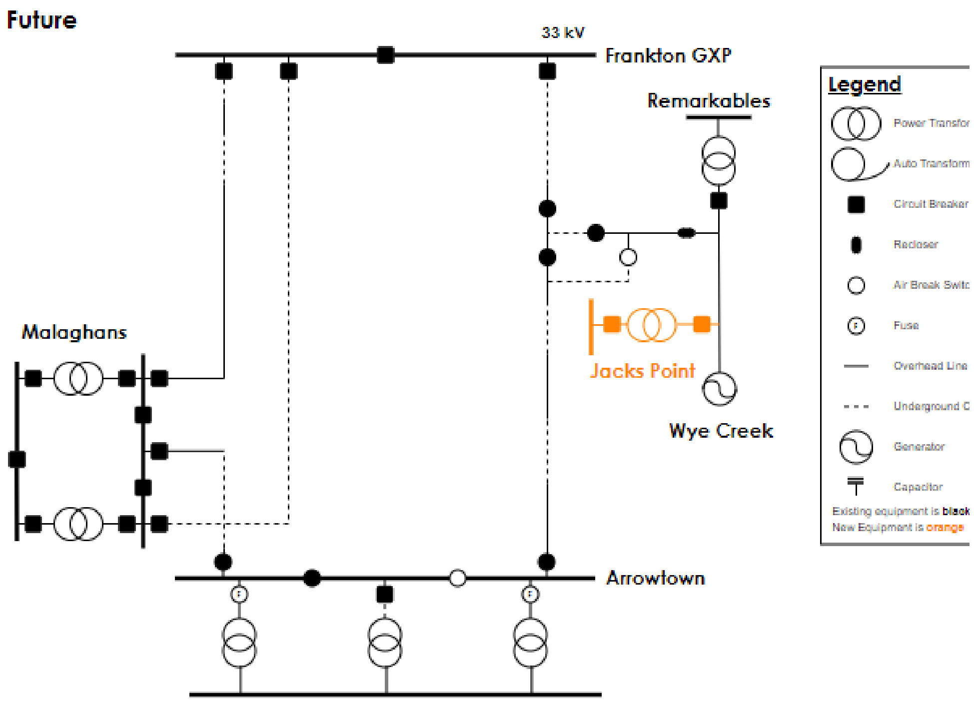


Table 17-20: Malaghans Road Subtransmission Upgrade

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Malaghans Road Subtransmission Upgrade	Load Growth at Arrowtown Substation is expected to exceed the firm capacity of the Ferret 33 kV Subtransmission Conductor along Malaghans Road	• Replace conductor • Thermally Upgrade the existing conductor • Install new 33 kV underground cable	**Replace existing 33 kV conductor along Malaghans Road** This solution provides the following benefits: • Increases firm transmission capacity to meet growing load	2031–32	4.5

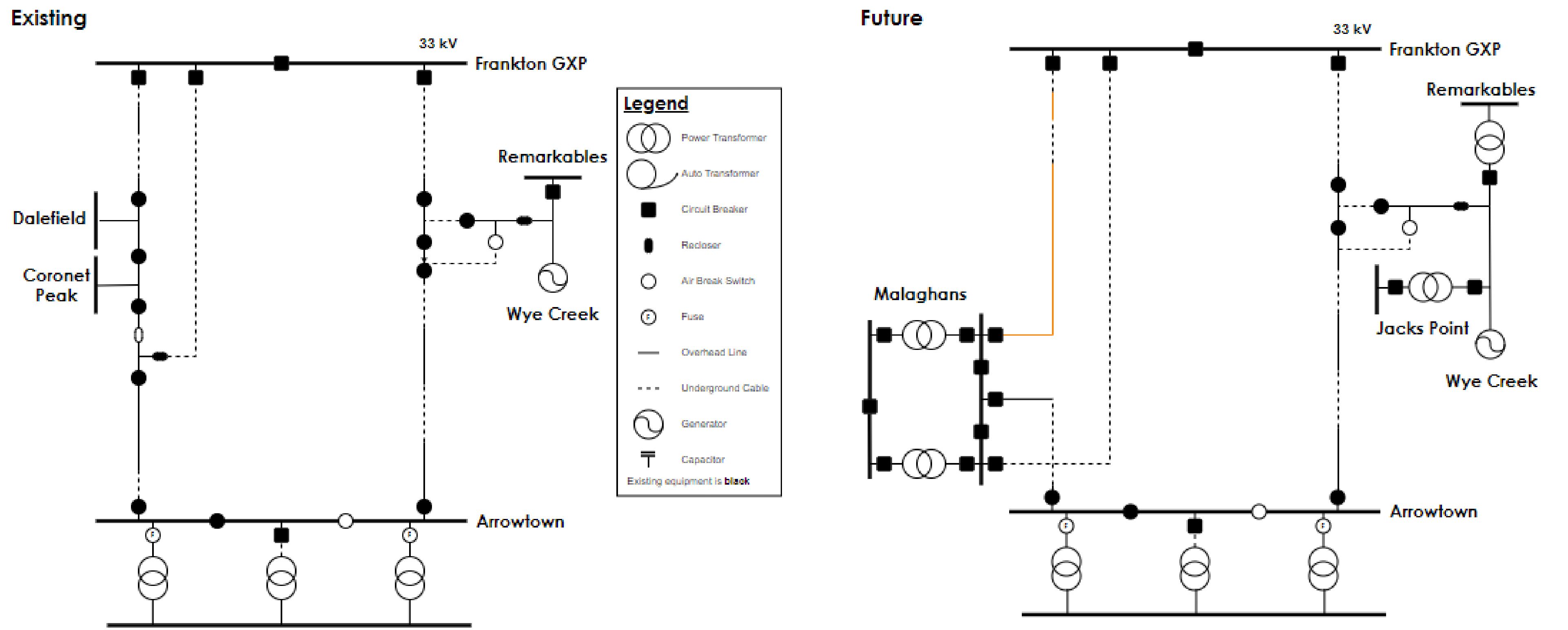


Table 17-21: Whitechapel zone substation (New Arrowtown)

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Whitechapel zone substation (New Arrowtown)	The growing load in the Arrowtown area is exceeding the firm capacity that can be supplied by the existing Arrowtown Substation	• Rebuild the Arrowtown substation on the existing site • Construct a substation on a new site	**Construct a substation on a new site** This solution provides the following benefits: • Provides substation capacity to meet growing load • Allows 33 kV network to be run closed avoiding outages for a single circuit fault • Replaces equipment that will soon need to be replaced for age-based reasons	2031–33	11

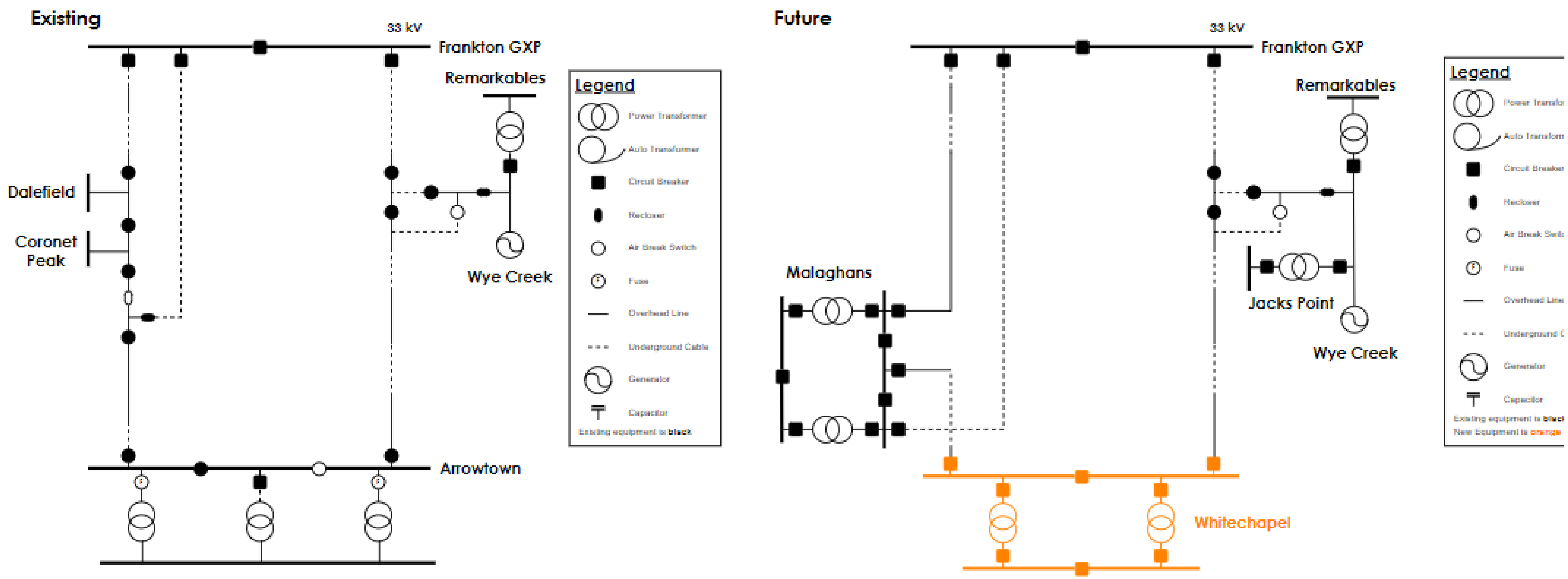
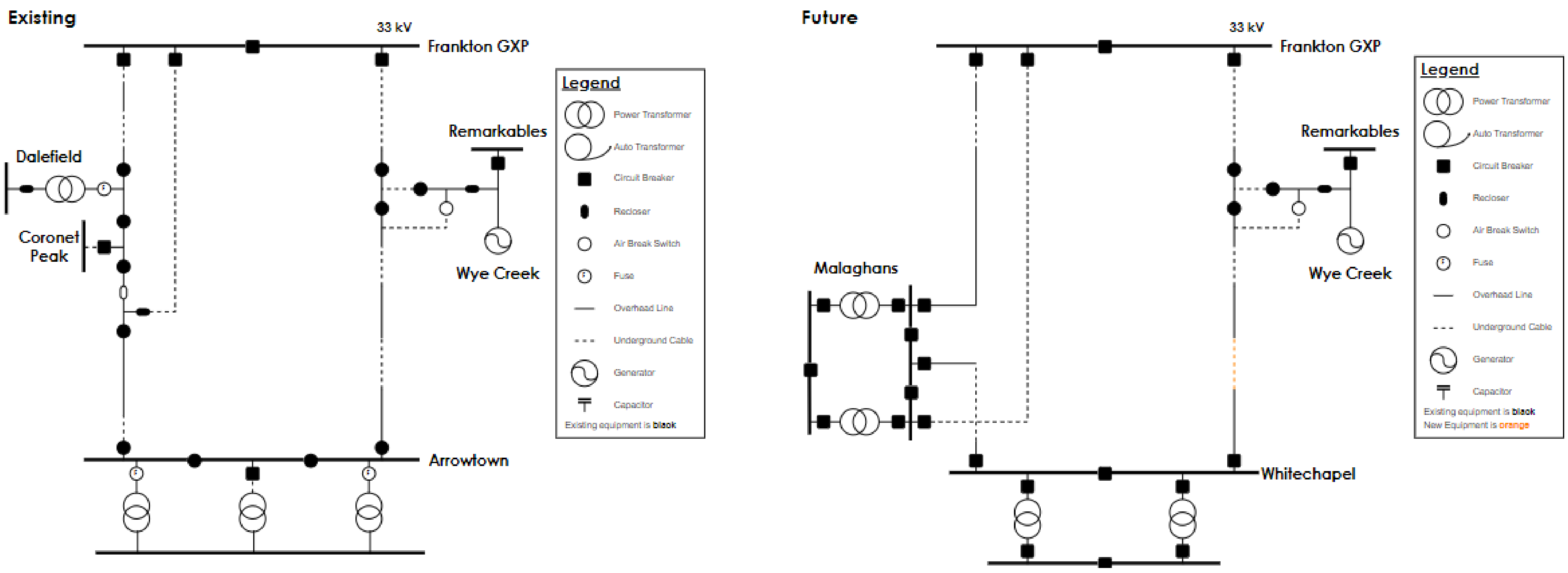


Table 17-22: Lake Hayes Subtransmission Cable Upgrade

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Lake Hayes Subtransmission Cable Upgrade	The 33 kV cable around Lake Hayes is thermally rated at 14 MVA, limiting the firm capacity that can be supplied to Arrowtown	• Do nothing • Replace cable	Replace the 33 kV cable around Lake Hayes This solution provides the following benefits: • Improves the firm capacity that can be supplied by Arrowtown (or future Whitechapel) Substation	2034–35	1.2



Appendix G: Preventive Maintenance Activities

Table 17-23 gives an overview of the preventive maintenance activities we carry out on our assets, along with the typical frequencies of these inspections.

Frequencies and detailed contents of activities are tailored based on asset type, location and criticality, but the below table gives the foundation of our planned maintenance programme.

Table 17-23: Preventive Maintenance Activities

Portfolio/Fleet	Activity	Frequency
OH – Structures	Inspection – Deuar/dig/visual test for wooden poles, visual inspection for steel and concrete poles	5-yearly
OH – Conductor	Inspection – Visual	5-yearly
OH – Conductor	Inspection – Thermal; joints and connections	5-yearly
OH – ABS	Inspection – Thermal; joints and connections	5-yearly
OH – miscellaneous (Dunedin sub-network)	Inspection – Acoustic; joints, connections, insulators, bushings	Biennially
OH Miscellaneous (FENZ Designated Fire Prohibited Zones)	Inspection – Acoustic: joints, connections, insulators, bushings	Annually
Underground cables – subtransmission		**Frequency**
Oil and gas-filled pressure tests		Fortnightly
Alarm tests to confirm condition of alarms		Biannually
Ground based visual inspections of cable terminations		Annually
Oil and gas-filled outer sheath electrical integrity testing		Annually
On-line partial discharge testing		Triennially
Underground cables – distribution		**Frequency**
Clean dry-type cable terminations on zone substation circuit breakers		4-yearly
Inspection of cable risers		5-yearly
Opportunistic cleaning of dry-type cable terminations on RMUs and distribution transformers		10-yearly (during RMU/ transformer maintenance)
Opportunistic insulation resistance and polarisation index testing of cables terminated on RMUs/ transformers		10-yearly (during RMU/ transformer maintenance)
Underground cables – LV		**Frequency**
Inspect visible LV cable and terminations		5-yearly (during pole inspections) During LV enclosure inspections During ground-mounted transformer inspections
Clean LV cable terminations		During oil-filled RMU maintenance
Buildings and grounds		**Frequency**
Visual inspection & routine maintenance		Fortnightly
Petroblock cleaning		Monthly
Cleaning		Fortnightly
Oil interceptor cleaning		Annually

Crane certifications	Annually
Petroblock replacement	6-yearly
Oil sensor functionality check	4-yearly
Painting	10-yearly or as required

Power transformers	Frequency
Ground-level visual inspection to identify apparent defects on the tank/pipework, including oil leaks, check thermometer, ensure pumps and fans are operating correctly, and record tap-changer cyclometer, oil level recordings	Monthly
Dissolved gas analysis (DGA) and oil quality analysis	Annually
Thermography and partial discharge inspection	Annually
Tap-changer DGA and oil quality analysis	2-yearly
Tap-changer DGA, oil quality and tap-changer signature analysis	4-yearly
DGA, oil quality and furan analysis to evaluate the rate of transformer ageing	4-yearly
Transformer out-of-service maintenance; including detailed close visual inspection of bushings, pipework, and systems. Electrical insulation and resistance tests. Confirm correct operation of cooling systems.	4-yearly
Tap-changer maintenance; occurrence based on either a time period or a set number of operations, to ensure continuing operation and reliability of tap-changer.	Variable according to tap-changer type
Painting	15-yearly or as required

Zone Substation Switchgear	Activity	Frequency
Indoor and outdoor	Visual inspection of circuit breakers including cyclometer readings	Monthly
Indoor and outdoor	Thermography and partial discharge inspections	Annually
Indoor and outdoor	Oil circuit breaker maintenance; circuit breaker contacts assessment and insulating oil replacement Maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion. Electrical condition assessment is undertaken.	4yearly
Indoor and outdoor	Vacuum/SF_6 circuit breaker maintenance; maintain/lubricate operating mechanism. Confirm correct operation of system. Identify and treat corrosion. Carry out electrical condition assessment. Contact gap measurements as specified by vendor.	4-yearly
Outdoor	Air break switch maintenance; identify visually apparent defects, diagnostic testing, operational checks, visual insulator inspection, cleaning, minor repairs.	4-yearly
Indoor and outdoor	Oil CB Post fault maintenance	Operations based

Ancillary zone substation equipment	Frequency
Outdoor structure and buswork visual inspection	Monthly
Outdoor 317 Hz / 1050 Hz ripple plant visual inspection (at monthly zones)	Monthly
Local service system visual inspection	Monthly
Mobile substation vehicle roadworthiness	Annually
317 Hz ripple plant inspection and maintenance	Annually
1050 Hz ripple plant maintenance	Annually
Portable earths inspection and testing	6-monthly
Fire protection inspection	Annually
Fire protection pressure testing	5-yearly
Earth grid testing	5-yearly

Ground mounted distribution switchgear		Frequency
Visual inspection focusing on site condition, site security, paint condition, corrosion, labels, earthing, insulate medium levels, unit tilt, plus acoustic, partial discharge and thermography analysis		Annually
Testing of protection; exercise of switch mechanisms; interlocks operational; where fitted, fault indicators operational, actuators operational; where fitted, battery test; plus the annual inspection tasks		2.5-yearly (only for units with circuit breaker functionality and fitted with protection)
Where possible to complete without an outage, exercise switches to prove functionality, plus the annual inspection tasks		5-yearly
Invasive maintenance encompassing fuse carriers checks, fixed and moving contacts checked, full oil change, tank clean/sludge removal, flushing tank with clean oil, removed and new oil test for dielectric strength, moisture content, and oil acidity, electrical tests of fuses and unit plus the annual inspection tasks Opportunistic light touch maintenance of any connected distribution substations de-energised as part of outage plus electrical condition tests of attached distribution cables that are de-energised		10-yearly (only for L&C and ABB oil-filled units)
LV board inspections		With associated ground-mounted switchgear inspection & maintenance
LV enclosures		**Frequency**
LV enclosure inspection and minor repairs as/if required		5-yearly
Pole-mounted fuses		**Frequency**
Visual inspection of fuses for corrosion, defects and gathering of type information		5-yearly
Thermography of HV and LV transformer fuses		5-yearly as part of OH inspection
Reclosers		**Frequency**
Visual inspection, thermographic testing		Annually
Maintenance service – test protection, rectifier, SCADA points, bypass checks, check settings, adjust settings if required, replace battery		4-yearly
Ancillary distribution substations		**Frequency**
Underground substation inspection and clean-up including confined space gas checks, equipment inspections, cleaning up of any debris that has passed through the street level grill, alarm checks		Biannually
Distribution earth testing on all assets with earths		6-yearly
Underground substation electrical equipment inspection/maintenance		As per individual fleet assets
Distribution transformers	**Activity**	**Frequency**
Ground mounted	Assess corrosion/oil leaks, evaluate enclosure/cover integrity, assess locks/security, consider noise, partial discharge, visual inspection of earths, read MDIs	5-yearly
Ground mounted	Air filled cable box inspections and termination cleaning	When RMUs co-located with ground-mounted transformers are maintained/as required following transformer inspection
Pole-mounted – All	Noting of obvious pole-mounted transformer defects during pole inspection, e.g. significant oil leak, noting hotspots from thermography, corroding pole/platform supports	5-yearly
Pole-mounted – >100 kVA	Assess corrosion/oil leaks, consider noise, partial discharge, visual inspection of earths, read MDIs, thermal inspection of joints and connections, check MDI structure, check oil levels.	5 yearly

Voltage regulators		Frequency
Visual inspection, thermographic inspection, tap-changer operation, communications checks		Annually
Maintenance service		6-yearly, or 100,000-120,000 operations
Mobile distribution substations and generators		**Frequency**
Standby generator inspection to confirm operability and condition		Fortnightly
Standby generator oil and coolant testing		Biannually
Mobile substation inspection, testing and maintenance including activities such as cable tests, COF, vehicle servicing		Biannually
Mobile generator inspection to confirm operability and condition		Prior to use and after use
Mobile substation inspection upon return from service		Whenever returned from service
Mobile generator full service		Every 500 hours of use
Standby generator full service		4 to 6-yearly
Secondary systems	**Activity**	**Frequency**
DC systems	Battery bank and charger visual inspections	Monthly
DC systems	Battery bank and charger tests	Annually
RTUs	Visual inspection	Monthly
RTUs	Routine testing of all RTU points to ensure proper operation in entirety including communications bearers	Generally, 4-yearly

Appendix H: Major Renewal Projects

Sub-network	Category	Major Renewal Projects	From	To	Capex ($m)
Dunedin	Zone Substations	**Green Island Substation Rebuild** We will build a new substation adjacent to the existing substation, complete with a new building, transformers, indoor switchgear, and ancillary equipment. The existing substation will be decommissioned following commissioning of the new substation.	2023	2026	11.2
Dunedin	Zone Substations	**Smith Street 11 kV Switchboard Replacement** We are decommissioning the existing oil-insulated indoor 6.6 kV switchgear at end-of-life and demolishing the switch room to construct a new one on the same footprint and install new indoor vacuum-insulated switchgear.	2024	2026	6.5
Dunedin	Zone Substations	**Halfway Bush 11 kV Switchboard Replacement** We will decommission the existing indoor 6.6 kV oil-insulated switchgear at end-of-life and replace with new indoor vacuum-insulated switchgear.	2026	2027	4.9
Dunedin	Zone Substations	**Port Chalmers Transformer Replacement** We will replace the two 7.5 MVA transformers at end-of-life with a refurbished 15 MVA transformer and a new 24 MVA transformer.	2027	2028	4.4
Dunedin	Zone Substations	**Smith Street Substation Renewal – Transformers** We will decommission the existing 15 MVA transformers that will be at end-of-life and replace with new 24 MVA transformers.	2029	2030	5.0
Dunedin	Zone Substations	**Kaikorai Valley Substation Renewal** This project involves replacing the existing South Wales 6.6 kV bulk oil switchgear, which will be at end-of-life; as well as the protection equipment, which is electro-mechanical, has performance issues, and has reached the end of its serviceable life.	2031	2032	4.8
Dunedin	Zone Substations	**Willowbank Substation Renewal** The existing substation is approaching end-of-life, and the renewal project will involve the decommissioning and replacement of all equipment.	2027	2028	9.7
Dunedin	Zone Substations	**East Taieri Substation Renewal** This project aims to replace all equipment at end-of-life and mitigate the fire and flooding risks at the site. The project involves the replacement of power transformers, switchgear, and protection equipment – all of which are considered to be approaching end-of-life, with performance issues.	2032	2033	10.6
Dunedin	Zone Substations	**South City 11 kV Switchboard Replacement** We will decommission the existing indoor 6.6 kV oil-insulated switchgear at end-of-life and replace with new indoor vacuum-insulated switchgear.	2031	2032	5.8
Dunedin	Zone Substations	**Corstorphine Transformer Replacement**	2032	2034	10.8

Sub-network	Category	Major Renewal Projects	From	To	Capex ($m)
Dunedin	Zone Substations	**North East Valley 11 kV switchgear replacement** We will replace existing 11 kV indoor SF_6 switchgear and associated auxiliary systems that will be at end-of-life.	2035	2036	3.2
Dunedin	Zone Substations	**Mosgiel Substation Rebuild** This project involves renewing two 10 MVA power transformers and converting 33 kV outdoor switchgear to indoor.	2028	2030	9.8
Dunedin	Subtransmission Cable Projects	**Kaikorai Valley PILC Cable Replacement**	2025	2027	8.2
Dunedin	Subtransmission Cable Projects	**Corstorphine Oil Cable Replacement**	2029	2031	9
Dunedin	Subtransmission Cable Projects	**Willowbank Gas Cable Replacement**	2027	2029	11.9
Dunedin	Subtransmission Cable Projects	**St Kilda Cable Replacement**	2031	2033	4.7
Dunedin	Subtransmission Conductor	**Waipori Stages 2B – 6**	2024	2032	34.6
Central Otago	Zone Substations	**Alexandra 33 kV and 11 kV Outdoor-Indoor Conversion** We will decommission outdoor 33 kV and 11 kV switchgear as it is now at end-of-life and replace with new 33 kV and 11 kV indoor switchgear.	2024	2026	9.0
Central Otago	Zone Substations	**Lauder Flat Transformer Replacement** This project involves replacement of transformer and associated auxiliary equipment at end-of-life.	2036	2037	1.4
Central Otago	Subtransmission Cable Projects	**MEG Cable Replacement**	2033	2035	7.1
Queenstown	Zone Substations	**Queenstown 33 kV Outdoor Switchyard Renewal** This project involves decommissioning seven 33 kV outdoor oil insulated CBs, three 33 kV disconnectors and associated protection relays, all at end-of-life and replacing with new indoor switchgear.	2035	2036	3.6
Queenstown	Zone Substations	**Queenstown Substation 11kV switchboard & 33kV Switchgear** This project involves replacement of 11kV outdoor switchgear with indoor switchgear as well as renewal of protection relays for 33 kV switchgear at end-of-life.	2023	2026	5.3
Queenstown	Zone Substations	**Remarkables T1 replacement** This project involves replacement of transformer and associated auxiliary equipment at end-of-life.	2032	2033	1.4
Queenstown	Zone Substations	**Fernhill 11 kV Switchgear Replacement** This project involves replacement of switchgear.	2032	2033	1.4

*Feasibility studies to better understand Subtransmission Cable Projects routes and subsequent costs are currently underway.

Appendix I: Disclosure Requirements

Requirement			AMP reference
3		The AMP must include the following-	
3.1		A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Navigating this Plan Executive Summary
3.2		Details of the background and objectives of the EDB's asset management and planning processes;	Section 1.1 Chapter 6
3.3		A purpose statement which-	
	3.3.1	makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	Section 1.1 Chapter 6
	3.3.2	states the corporate mission or vision as it relates to asset management;	Section 1.1
	3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	Section 6.1
	3.3.4	states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	Section 6.1
	3.3.5	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	Section 6.2
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 1.1.
3.5		The date that it was approved by the directors;	About this Plan
3.6		A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	
	3.6.1	how the interests of stakeholders are identified	Section 4.1
	3.6.2	what these interests are;	Section 4.1
	3.6.3	how these interests are accommodated in asset management practices; and	Section 4.3 Section 6.2
	3.6.4	how conflicting interests are managed;	Section 4.3

Requirement		AMP reference
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1	governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	Section 6.3
3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 6.3
3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	Section 6.3 Section 13.1.4 Section 16.1.2
3.8	All significant assumptions-	
3.8.1	quantified where possible;	Chapter 8 Section 10.1 Section 15.5
3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including-	
3.8.3	a description of changes proposed where the information is not based on the EDB's existing business;	Not Applicable
3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Chapter 8 Section 15.5
3.8.5	the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	Section 15.5
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;	Chapter 8 Section 15.5
3.10	An overview of asset management strategy and delivery;	Chapter 6 Chapter 7
3.11	An overview of systems and information management data;	Chapter 6
3.11.1	To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-	
(a)	the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	Section 6.4 Section 11.1.4
(b)	the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	Section 6.4 Section 11.1.4

Requirement			AMP reference
	(c)	the systems and controls to ensure the quality and accuracy of asset management information;	Section 6.4 Section 11.1.4
	(d)	the extent to which these systems, processes and controls are integrated;	Section 6.4
	(e)	how asset management data informs the models that an EDB develops and uses to assess asset health; and	Section 6.4 Section 6.5 Section 7.3
	(f)	how the outputs of these models are used in developing capital expenditure projections.	Section 7.3 Chapter 11
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 6.4 Section 11.1.4
3.13		A description of the processes used within the EDB for-	
	3.13.1	managing routine asset inspections and network maintenance;	Section 6.5 Section 11.2 Appendix G
	3.13.2	planning and implementing network development projects; and	Chapter 10 Section 16.1.2
	3.13.3	measuring network performance.	Section 5.1 Appendix E
3.14		An overview of asset management documentation, controls and review processes.	Chapter 6
3.15		An overview of communication and participation processes.	Chapter 4 Chapter 6 Chapter 13 Section 16.1.2
3.16		The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Section 15.1
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.	Navigating this Plan

Requirement			AMP reference
Assets covered			
4		The AMP must provide details of the assets covered and non-network solutions, including-	
4.1		a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	
	4.1.1	the region(s) covered;	Chapter 3
	4.1.2	identification of large consumers that have a significant impact on network operations or asset management priorities;	Sections 3.2, 3.3, 3.4
	4.1.3	description of the load characteristics for different parts of the network;	Sections 3.2, 3.3, 3.4
	4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 3.1.4
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 3.1.4
	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 3.1.2 Sections 10.5, 10.6, 10.7
	4.2.3	a description of the distribution system, including the extent to which it is underground;	Chapter 3
	4.2.4	a brief description of the network's distribution substation arrangements;	Chapter 3
	4.2.5	a description of the low voltage network including the extent to which it is underground;	Chapter 3
	4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	Chapter 3 Section 11.9
	4.2.7	a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party	Section 9.5
4.3		If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Sections 3.2, 3.3, 3.4

Requirement			AMP reference
Network assets by category			
4.4		The AMP must describe the network assets by providing the following information for each asset category-	
	4.4.1	voltage levels;	Chapter 3 Chapter 11
	4.4.2	description and quantity of assets;	Chapter 11
	4.2.3	age profiles; and	Chapter 11
	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.	Chapter 11
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);	Chapter 11
	4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	Chapter 11
	4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Chapter 11
	4.5.4	other generation plant owned by the EDB.	Not applicable
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 5.1
6		Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Section 5.1 Appendix B Schedule 12d
7		Performance indicators for which targets have been defined in clause 5 should also include-	
7.1		Consumer-oriented indicators that preferably differentiate between different consumer types; and	Chapter 4 Chapter 5
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.	Chapter 11

Requirement			AMP reference
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.	Chapter 4 Section 5.1 Appendix E
9		Targets should be compared to historic values where available to provide context and scale to the reader.	Section 5.1
10		Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	Chapter 5 Appendix E
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;	Chapter 10
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;	Chapter 10
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;	Sections 6.2.3, 6.5
11.4		The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
	11.4.1	the categories of assets and designs that are standardised; and	Section 6.5 Chapter 11
	11.4.2	the approach used to identify standard designs;	Section 6.5
11.5		A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Chapter 9
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;	Sections 9.1, 9.2 Section 10.1
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;	Chapter 9 Sections 10.1, 10.2
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;	
	11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 10.3
	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;	Sections 10.4 - 10.7

Requirement			AMP reference
	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	Sections 10.5, 10.6, 10.7
	11.8.4	discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network	Chapter 9 Chapter 10
11.9		Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	
	11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	Chapter 9 Sections 10.1, 10.2 Appendix F
	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; and	Sections 9.5, 9.6 Sections 10.1, 10.2 Appendix F
	11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Sections 9.5, 9.6
11.10		A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	
	11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	Sections 10.5, 10.6, 10.7 Appendix F
	11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	Sections 10.5, 10.6, 10.7 Appendix F
	11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	Sections 10.5, 10.6, 10.7 Appendix F
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; and	Section 3.1.5 Section 9.5
11.12		A description of the EDB’s policies on non-network solutions, including-	
	11.12.1	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;	Section 9.6
	11.12.2	the potential for non-network solutions to address network problems or constraints; and	Section 9.6
	11.12.3	how information on current and forecast constraints (both load and injection) is shared with potential providers of non-network solutions. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2 of Attachment A.	Sections 9.5, 9.6 Sections 10.5, 10.6, 10.7

Requirement			AMP reference
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 6.5
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-	
	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 6.5 Chapter 11 Appendix G
	12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Chapter 11
	12.2.3	budgets for maintenance activities broken down by asset category for the AMP planning period;	Section 11.2
12.3		Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
	12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	Section 6.5 Chapter 11
	12.3.2	a description of innovations that have deferred asset replacements;	Chapter 11
	12.3.3	a description of the projects currently underway or planned for the next 12 months;	Appendix H
	12.3.4	a summary of the projects planned for the following four years (where known); and	Appendix H
	12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	Appendix H
12.4		The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	All asset types from clause 4.5 are included; however, we do use our own asset categories – Section 11.1
12.5		Identification of the approach used for modelling capital expenditure projections for lifecycle asset management. This must include an explanation of:	
	12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	Section 6.5 Section 7.3 Chapter 11

Requirement			AMP reference
	12.5.2	the rationale for using the particular approach for each asset category.	Section 6.5 Section 7.3 Chapter 11
12.6		Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Sections 6.5, 7.5, 8.2 Section 11.2
12.7		The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	Sections 9.6, 11.1 Chapter 15
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 14.1
13.2		development, maintenance and renewal policies that cover them;	Section 14.2
13.3		a description of material capital expenditure projects (where known) planned for the next five years; and	Chapter 12
13.4		a description of material maintenance and renewal projects (where known) planned for the next five years.	Chapter 12
Risk Management			
14		AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1		Methods, details and conclusions of risk analysis;	Chapter 7
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 7.4
14.3		A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Section 7.4
14.4		Details of emergency response and contingency plans.	Section 7.4
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;	Chapter 15
15.2		An evaluation and comparison of actual service level performance against targeted performance;	Section 5.1

Requirement			AMP reference
	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 6.6
	15.4	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 5.1 Section 6.7
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; and	Chapter 6 Chapter 16
	16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP	Section 2.1 Section 6.3
Requirements to provide qualitative information in narrative form			
17		AMPs must include the following qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
		[2.1.2 Aurora is not required to comply with clauses 17.1- 17.3 of Attachment A, except that its AMPs must include qualitative information in narrative form that describes its practices in a manner than complies with clause 17.2.2 of Attachment A.]	
Voltage quality and constraints			
	17.2	a description of the EDB's practices for:	
	17.2.2	monitoring load and injection constraints, including:	
	(a)	any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and	Sections 9.1, 9.5
	(b)	any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	Sections 9.1, 9.5

Requirement			AMP reference
Practices for connecting new consumers and altering existing connections			
17.4		a description of the EDB's practices for connecting consumers, including:	
	17.4.1	the EDB's approach to planning and management of-	
	(a)	connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	Section 4.4 Chapter 9 Section 16.1
	(b)	alteration to existing connections (offtake and injection connections);	Section 16.1
	17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;	Section 4.4 Section 6.2.3 Section 16.1
	17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections;	Section 16.1
	17.4.4	commonly encountered delays and potential timeframes for different connections; and	Section 16.1
	17.4.5	the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A.	Section 4.4 Chapter 9 Chapter 10 Section 16.1
New connections likely to have a significant impact on network operations or asset management priorities			
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:	
	(a)	how the EDB measures the scale and impact of new demand, generation, or storage capacity;	Section 9.1 Chapter 10
	(b)	how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account;	Chapter 8 Chapter 10
	(c)	how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity; and	Chapter 8 Chapter 9 Chapter 10
	17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	Chapter 8 Chapter 9 Chapter 10

Requirement			AMP reference
Innovation practices			
17.6		a description of the following:	
	17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	Section 6.4
	17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	Section 6.4
	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 6.4
	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; and	Section 6.4
	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 6.4
17.7		For the purpose of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	
Additional AMP disclosure requirements for Aurora			
18		Aurora must summarise in its AMP Aurora's development plan under clause 2.5.4(1) to develop and improve its:	
18.1		Asset data collection and asset data quality practices as specified in clause 2.5.4(1)(d);	Appendix C
18.2		Asset management practices and processes as specified in clause 2.5.4(1)(e)(i) to (iii);	Appendix C
18.3		Practices for identifying and reducing safety risks as specified in clause 2.5.4(1)(e)(iv);	Appendix C
18.4		Practices for estimating the costs of capital expenditure and operational expenditure projects and programmes as specified in clause 2.5.4(1)(f); and	Appendix C
18.5		Quality assurance processes as specified in clause 2.5.4(1)(g).	Appendix C

Appendix J: Director's Certificate

Certification for Year beginning Disclosures

Clause 2.9.1

We, Stephen Richard Thompson and Janice Evelyn Fredric, being directors of Aurora Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Aurora 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, 11c, 12a, 12b, 12c, and 12d are based on objective and reasonable assumptions which both align with Aurora Energy Limited's corporate vision and strategy and are documented in retained records.

Director

28 March 2025

Date

Director

28 March 2025

Date

28 March 2025