31 March 2024

ASSET MANAGEMENT PLAN

APRIL 2024 – MARCH 2034

Aurora ENERGY

NAU MAI, WELCOME

Who we are

Aurora Energy is one of the largest electricity networks in Aotearoa 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 Te Waipounamu, the South Island.

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 across Ōtākou in Ōtepoti Dunedin, Central Otago & Wānaka and Tāhuna Queenstown to over 200,000 people.

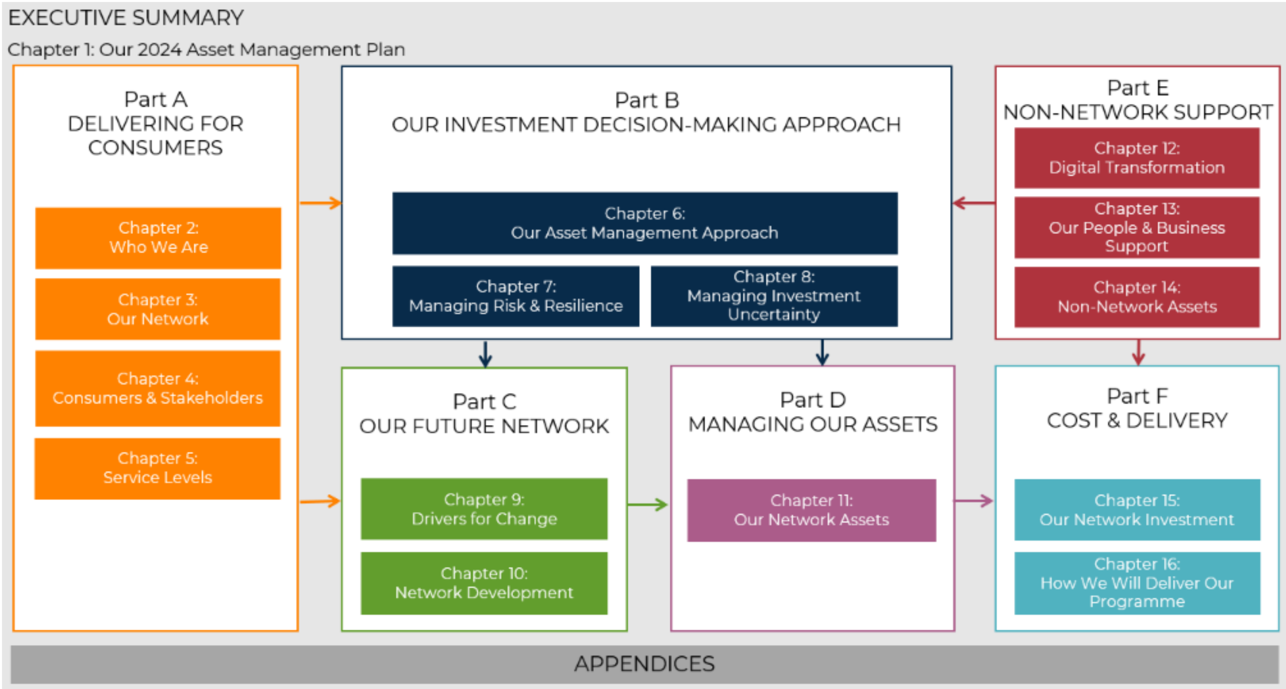
About this plan

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 2024 to 31 March 2034, and has been prepared to meet Commerce Commission Electricity Distribution Information Disclosure Determination requirements.

Our Board reviews and approves our AMP to ensure that it meets all regulatory requirements. This AMP was approved by our Board on 21 March 2024.

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 this 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 consumers' and stakeholders' needs and expectations, 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 our direction and thinking behind our investments. We have a significant focus in the short-term on ensuring the safety of our network, and a growing focus on the resilience and reliability of our network in the medium-term as we complete our safety-related objectives.

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. It 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.

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CHAPTER 1

OUR 2024 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 vision of **'enabling the energy future of our communities'**.

This AMP is focused on our commitment to building an electricity network that delivers a safe and reliable supply now and a sustainable and digitally enabled supply in the future across all our sub-networks.

1.1.1. AMP objectives

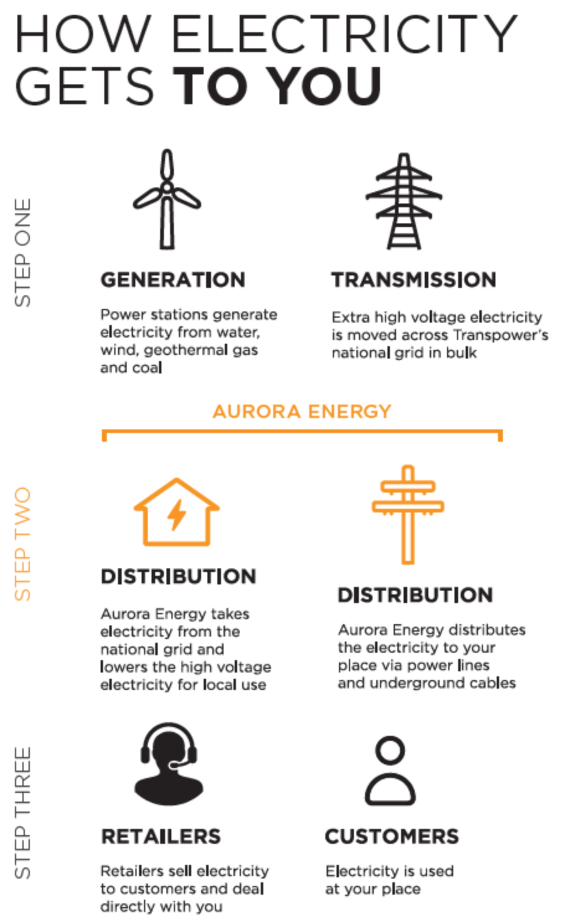
The objectives of our 2024 AMP are to:

- Continuously improve the safety of our assets through effective asset management and planning.
- Outline asset management and planning strategies that effectively serve the evolving needs of our community.
- Invest in our infrastructure to facilitate network evolution and anticipated energy demands.
- Implement asset management practices aimed at optimising lifecycle costs while ensuring the health and performance of our assets.
- Outline emerging risks and define strategic responses to strengthen network resilience against potential future threats.
- Promote consumer engagement by fostering transparency in our operations.
- Ensure regulatory compliance by adhering to relevant laws, regulations, and industry standards.
- Leverage 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 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 Ōtākou in Ōtepoti Dunedin, Central Otago, Wānaka and Tāhuna Queenstown. Our principal regulators are the Commerce Commission and the Electricity Authority.

Figure 1-1: How electricity gets to you



AMP PLANNING PERIOD

Our 2024 AMP covers a 10-year planning period, from 1 April 2024 to 31 March 2034. This marks the beginning of the 2025 regulatory year (RY25).

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 H.

CPP DEVELOPMENT PLAN

We are also working to our Customised Price-quality Path (CPP) regulatory approval, which provides a programme of spending to undertake essential maintenance and upgrades on the network for the period 1 April 2021 to 31 March 2026.

As part of our CPP application, 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 towards key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe that improvements will bring genuine benefit to consumers. The Development Plan is available on the Aurora Energy website.

1.2. DEVELOPING OUR AMP

Reflecting our ongoing asset management improvement programme, this 2024 AMP builds upon our AMP from last year. We identified areas to improve by analysing AMP23 and learning from other EDBs. Our subject matter experts and function managers contributed to different sections, providing detailed and specialised knowledge. AMP24 is the result of a consultative team effort, integrating these contributions for a practical representation of our strategies and methodologies.

The new structure in AMP24 is designed to offer a clear and pragmatic view 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 AMP24, 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 Period.

Change	Description	AMP Reference
Our Network	Throughout the AMP we have focused on providing key information summarised for each of our sub-networks. This enables consumers and stakeholders in different geographical locations to find the information that is most meaningful to them.	Chapter 3
Engaging With Consumers	In AMP24, we have strengthened the link between our engagement with consumers and how their feedback informs what we invest in.	Chapter 4
Service Levels	We want to clarify to consumers what we are delivering. This new chapter highlights our focus on the service levels we provide consumers, and how these change over time.	Chapter 5
Our Biggest Risks	This section highlights the top risks identified through our risk management framework, as well as key mitigation measures and responses as part of our asset management approach.	Chapter 7
Climate Change & Resilience	The changing landscape of energy due to climate change prompts a focus on planning for the future, ensuring network capacity aligns with evolving consumer needs, and resilience against climate impacts.	Chapters 7 & 9
Managing Investment Uncertainty	Navigating uncertainty in investment forecasts involves addressing asset renewals, system growth, decarbonisation, reliability, resilience, and digital transformation.	Chapter 8
Digital Transformation	We have identified digital transformation as an enabler for efficiency and future energy choices for consumers.	Chapter 12
Lifecycle Management For Non-Network Assets	This section focuses on the maintenance and renewal of our facilities, technology assets, and motor vehicles.	Chapter 14
How We Will Deliver Our Programme	We invest in resources and staff development to ensure safe, quality, and cost-effective delivery of work programmes.	Chapter 16

1.3. EXECUTIVE SUMMARY

1.3.1. Our 2024 AMP

This Asset Management Plan (AMP) outlines Aurora Energy's approach to managing its electricity distribution assets during the period from 1 April 2024 to 31 March 2034. 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 *'to enable the energy future of our communities'*. We will deliver our purpose 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.

The new structure of AMP24 is designed to offer a clear and pragmatic view 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 AMP24, 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.

1.3.2. What's changed?

Previously, our AMPs focused on our investment programmes to prioritise network safety. While we continue to strongly prioritise safety in the short-term, this year's AMP reflects the steps we are taking on our journey to enhance the resilience and reliability of our network for consumers in the medium- to longer-term.

We have progressed with the delivery of our CPP objectives with a heavy prioritisation on safety of our assets. As the end of the CPP programme of investment in the network nears its completion on 31 March 2026, we are now more aware of future challenges that our industry is facing. We are encountering unprecedented uncertainty in our investment planning due to numerous factors, which we discuss in this AMP.

Climate change and the need to reduce carbon emissions are changing how we all think about energy. Our network must be able to support the 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 consumers use energy – whether to charge electric vehicles or connect solar to homes or businesses. We also want to help consumers understand how to lower overall energy costs by actively managing how electricity is used at critical times of the day.

Our purpose is to enable the energy future of our communities. Our strategic focus areas are shown in Figure 1-2. They drive the way we do business and how we invest in our network.

Figure 1-2: Our strategic focus areas

1.3.3. Our network

Our network is split into three sub-networks, each with 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 configuration.

1.3.4. 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 in the process of updating our commitments in our Customer Charter to ensure they reflect what consumers have told us they want. If the public supports these changes, there will be new documents that will outline what consumers can expect from us, what we need from them, our service levels, and what compensation we will provide if we fail to meet certain service levels.

We detail our consumer engagement in Chapter 4.

1.3.5. 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. We propose to expand these in 2024/2025 to reflect our progress and the changing landscape. 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. In the year ending March 2023, there were a small number of large outages, and we have since addressed the issues that caused them.

At the time of writing this AMP, the year ending March 2024 was tracking well, with an anticipated result aligned with our forecast for 2024.

1.3.6. 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 under the CPP framework, 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 that 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. This has taken us from an age-based approach to a more encompassing methodology that now forms a part of the lifecycle fleet strategies, which is explained in Section 6.4. Expanding our focus in the medium-term, we are developing a broader approach that encompasses reliability risks, 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.

The success of our risk-based approach is evaluated by verification of 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 to 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*, *Recover*. 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 enhance 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 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 6.6.

With a resiliency portfolio in our AMP and associated forecast expenditure of $20 million across the 10-year period, we can make further progress in areas such as critical spares and their storage facilities. Our strategy encompasses both actions undertaken and future exploratory work to better understand which assets are vulnerable to windstorms, for example.

ENSURING 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 must ensure that our assets are in good health and that we take actions to reduce the impact vegetation, severe weather, wildlife and third-party damage may have on our supply. We also try to reduce the impact of planned outages on consumers by notifying them well in advance via their retailers and our website.

The initiatives we have to reduce the frequency of faults on our network are given in Table 7-3, and the initiatives to reduce the impacts of faults on consumers are set out 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. Ultimately, we aim to establish better performance targets, monitor fault performance and identify optimal investment solutions, while supporting continual improvement. These reliability improvement goals are explained in Table 7-6.

1.3.7. 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 our asset management framework matures, we will continually review and update key process and documents to reflect any improvements.

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

1.3.8. Investment uncertainty

This year's AMP, much like its predecessor, finds us navigating a complex landscape characterised by various input drivers, each presenting a unique level of forecast uncertainty. Managing the extent of climate change is a global effort and is driving the emergence and expenditure on new technologies to capture carbon or eliminate its creation, alongside efforts to reduce the impact of climate change on our network. The emergence of new digital technologies create 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.

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

- Asset Renewal
- System Growth
- Decarbonisation and DER
- Reliability
- Resilience
- Digital Transformation
- Vegetation
- Consumer Poles

SYSTEM GROWTH FORECASTS

One of the greatest areas of uncertainty is the pace and impact of electrification 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 *capacity event reopeners*. This mechanism enables us to seek additional regulatory allowances at a later date when the uncertainty is removed from the need to invest. 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 to seek approval for system growth projects where the need occurs during the DPP4 period. For this approach to be effective, it will require the Commerce Commission to develop an efficient approvals process.

We have developed a list (see Table 8-1) of growth-related reopener projects which could be triggered during the DPP4 regulatory period. If the need case for all projects was to materialise, we anticipate the addition of $41.6 million of expenditure in our plan.

1.3.9. 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. Detailed in Section 9.4, we have developed three growth scenarios based on our decarbonisation study (*Sustainable*, *Chaotic*, and *Alternative energy*). We acknowledge the impacts of climate risk. 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.

GROWTH & SECURITY INVESTMENT

Growth and security planned expenditure are developed on the basis of a minimum viable plan to meet known capacity and security of supply gaps. From the three abovementioned growth scenarios developed from our decarbonisation study (see Section 9.4), we have based our forecasts on the *Sustainable* scenario. Based on these forecasts, we assume that we can shape the demand profile to enable a high utilisation level of the network. This scenario relies on our 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 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 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 can be different. We see a strong uptake of electric vehicles in Dunedin, and a strong uptake of solar generation in Central Otago. The Dunedin sub-network is a dense metropolitan network, with a meshed/interconnected architecture and an ability to transfer load to neighbouring substations and feeders. Large parts of Central Otago are isolated with limited or no ability to transfer load.

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 more details, see Section 4.4.

New connections range from a single new house through to a range of businesses and infrastructure. Central Otago growth is significantly higher than 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 a mix of cloud and on-premise solutions to ensure a sustainable, secure technology foundation during the CPP period.

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.

The transformation has four elements, which are discussed in detail in Section 21.1. They are:

- Digitising core enterprise processes

[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.

[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.

- Optimising network configuration and operations
- Enhanced business analytics/insights and people empowerment
- Critical digital technology enablers

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

1.3.10. 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 our 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. **Figures 1-3** to **1-5** 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

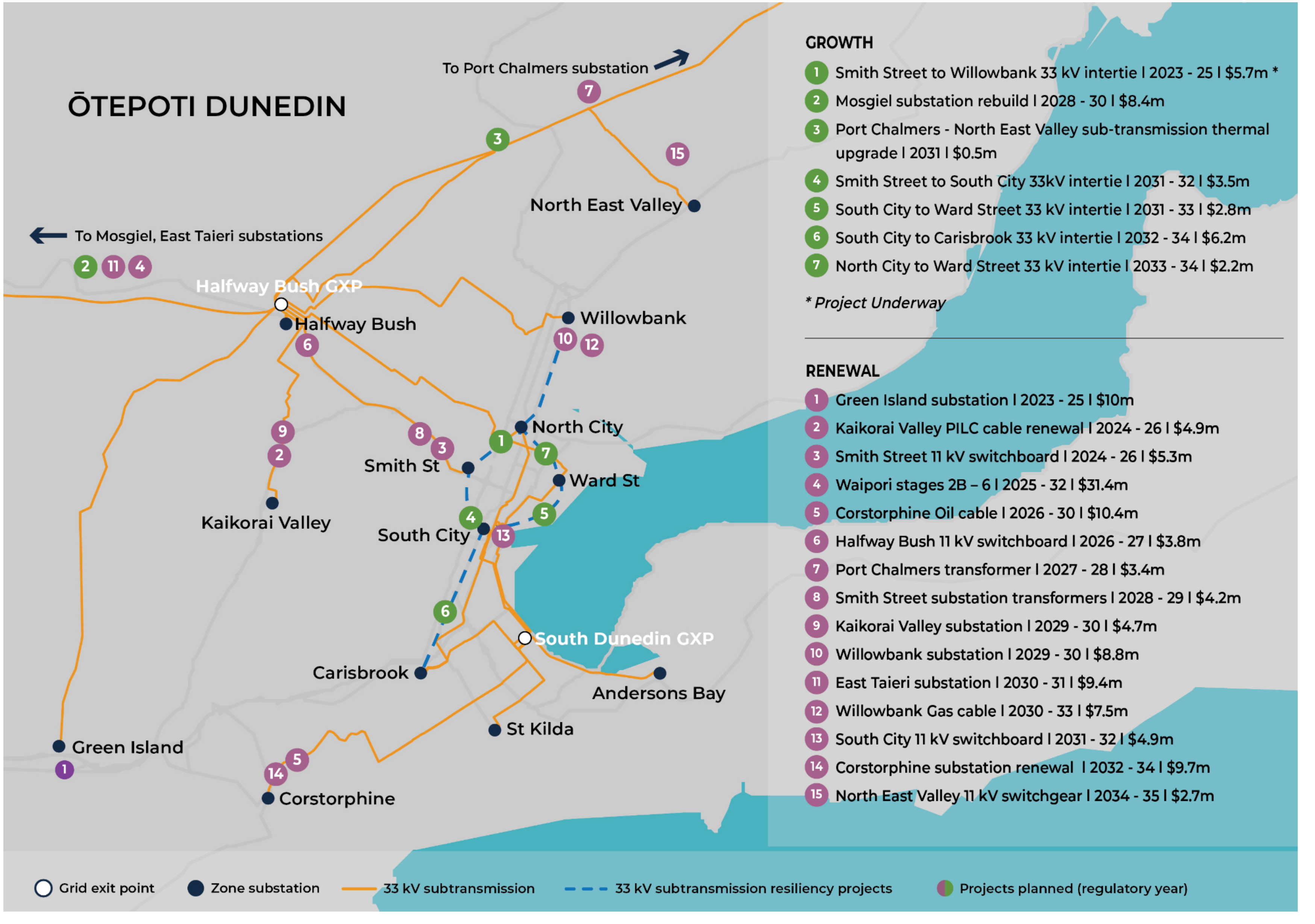


Figure 1-4: Large planned projects in the Central Otago & Wānaka sub-network

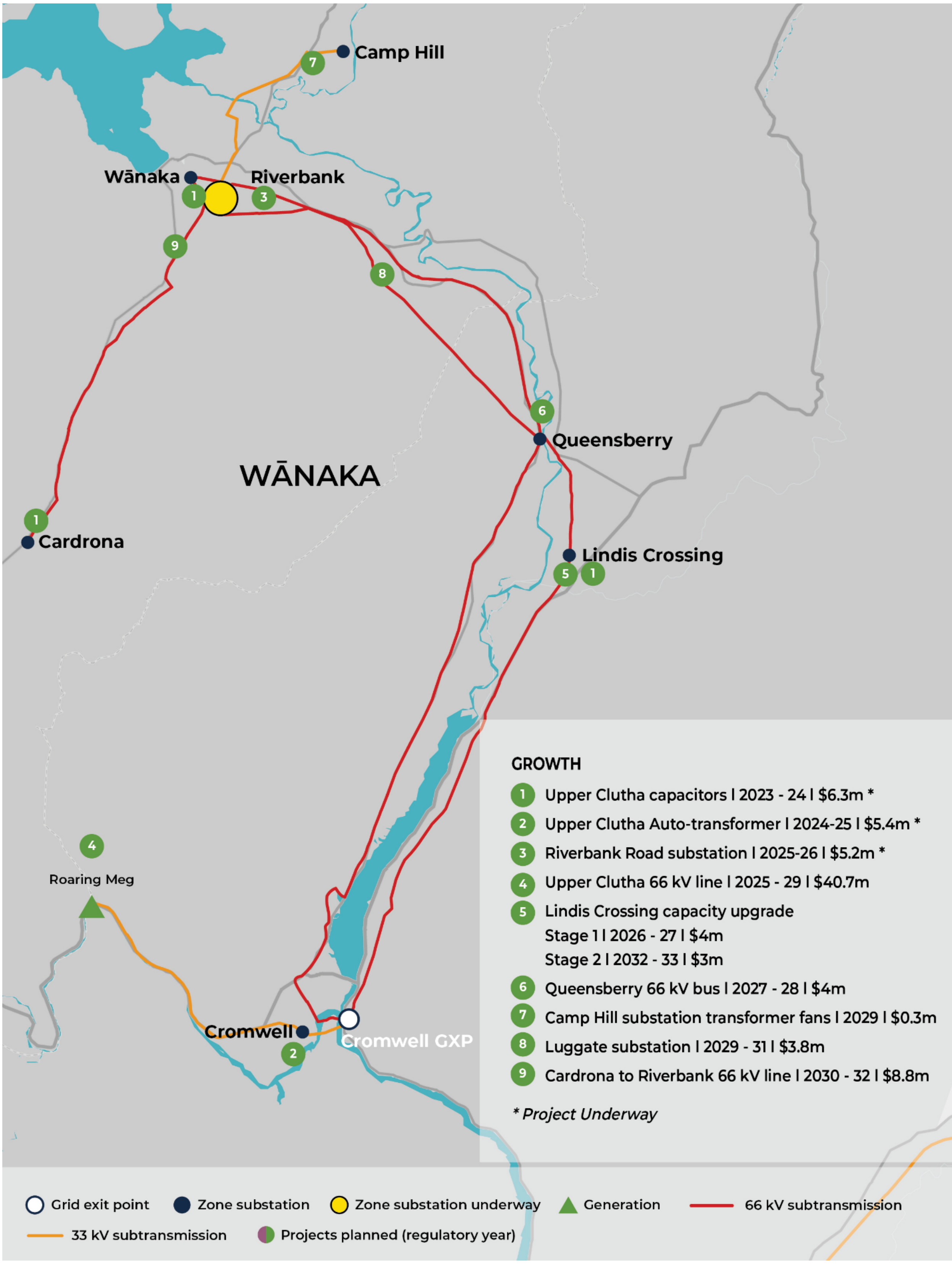
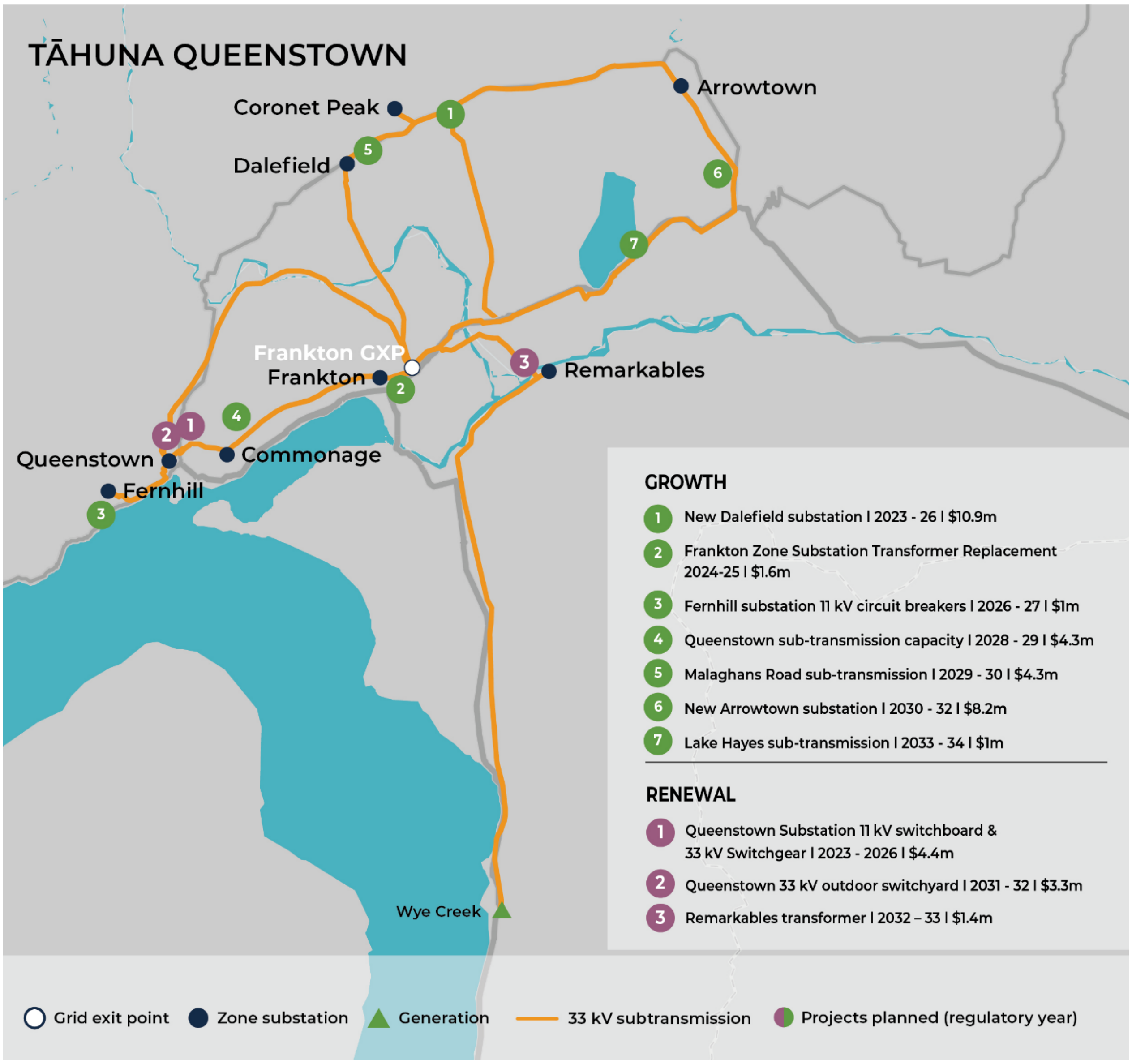


Figure 1-5: Large planned projects in the Queenstown sub-network



1.3.11. Network expenditure overview

Our capital and operational expenditure programmes are integral to the operation of our business throughout the 5-year CPP Period and beyond. We have continued to focus on the delivery of these programmes in RY24. Our AMP includes our current best forecasts based on our asset management strategies and using available network information. Through the development of Fleet Strategies, discussed further in Chapter 6, we have improved the quality of the asset information we collect. All financial values are expressed in $RY24 Constant price New Zealand dollars, except where specified otherwise.

When developing our 10-year plan we were mindful of cost escalation and affordability for consumers and our shareholders. We have developed what we consider to be a 'minimum viable plan' with no contingency. We have used the latest available asset condition inspection information to reduce expenditure in asset renewals to make way for high priority growth related projects. In some cases, we have also applied engineering judgement where we believe future inspection information is likely to show more favourable asset condition than the current data suggests.

Our CPP period (RY22 to RY26) plan prioritises safety for the public, contractors, and staff. There have been 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 into the DPP4 period we will continue to focus on safety and meeting strong growth including decarbonisation through electrification. Our plan also proposes to introduce reliability and resiliency programmes to:

- Enable reliability performance commensurate with the expectations of consumers/communities in areas of suboptimal performance
- 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 change the network configuration to improve reliability. We propose a modest but targeted programme, with $3.6 million in the DPP4 period and $10 million across the 10-year planning period.

Our resiliency programme will include the provision of additional spares and associated storage facilities, back-up generation, and possible hardening of storm exposed assets. We propose 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. For some fleets, however, we have reprioritised our plan for the remainder of the CPP period and beyond to ensure we meet our objective to reduce 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.

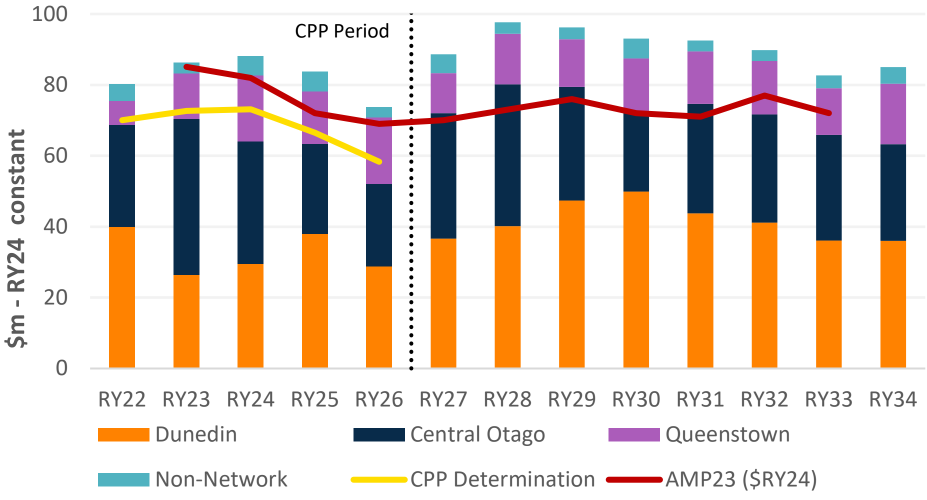
10-YEAR CAPEX FORECAST

Figure 1-6 shows our capital expenditure forecast for the AMP planning period, as well as our forecast variance to our previous AMP.

Cost escalation between AMP2023 and AMP2024 is the predominant driver of our increased forecasts. Analysis of our CPP annual delivery report unit rates and insights from our major field service agreement (FSA) tender round have concluded that a 10–15% increase reflects current as-built costs.

Furthermore, as part of our CPP improvement plan we have completed a cost estimation improvement initiative to better estimate the cost of our major zone substation projects for both renewals and growth expenditure drivers. We have had a track record of underestimating the cost of major projects and the new process better captures the scope of projects and utilises a refreshed unit rate schedule.

Figure 1-6: 10-year Capex forecast by sub-network, Total ($m)



The second largest driver of an increase in our forecasts is a small number of large projects to support strong growth. For example, a new 66 kV line in the Upper Clutha more than doubles our system growth forecasts in the DPP4 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.

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

To help manage affordability for consumers, we have reduced the forecast levels of renewal expenditure in the DPP4 period. This extends the period of safety risk backlog slightly, but in the context of strong growth this was deemed necessary to help ensure our plan is deliverable and affordable.

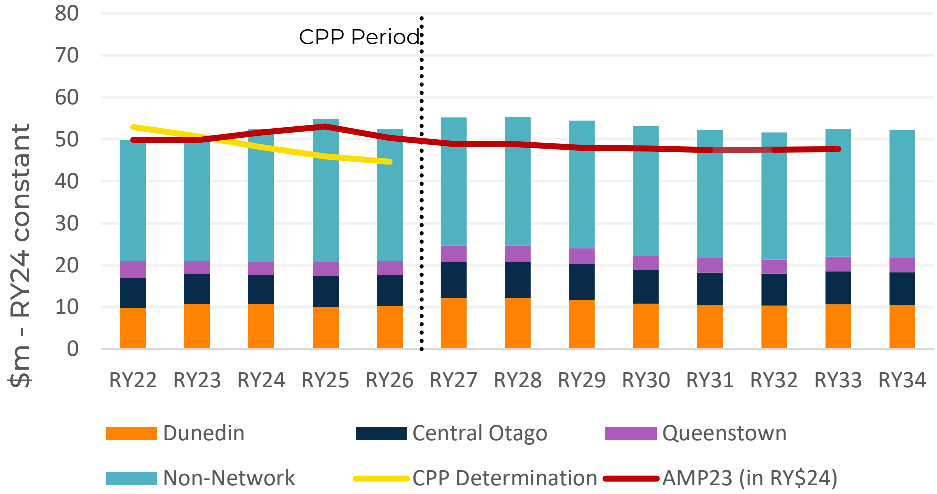
For AMP2024, we have considered the need for further investment in reliability and resiliency over the next 10 years.

Overall, these variances result in a circa 23% increase in capital expenditure over the reporting period. Table 15-5 in Chapter 15 gives a detailed view of our Capex forecast variance.

10-YEAR OPEX FORECAST

For network maintenance operational expenditure (Opex), the forecasts generally follow the same methodology as AMP23 using base step trend models. The forecasts include an increase in labour rates associated with the Field Service Agreement (FSA) tender, taking effect from RY25. Figure 1-7 shows our total operating expenditure forecast during the AMP planning period, as well as our forecast variance from our previous AMP.

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



Most of the preventive maintenance expenditure items are repetitive year-on-year. The Base forecast is calculated by analysing the RY23 expenditure to remove any expenditure items that could be considered ‘one-off’. Typical ‘one-off’ items include inspection trials or rollover from the previous year. We excluded $0.9 million of ‘one-off’ expenditure items to establish a Base forecast for RY24 of approximately $7.5 million.

The Step forecast is developed by identifying the forecast cost of known changes to preventive maintenance practices or short-term programmes of work not previously undertaken in the Base expenditure. As part of our continuous improvement work to better understand asset condition and respond to root cause fault information, we have made a number of step changes in our preventive maintenance forecast.

The following list provides a summary of the key changes:

- Introduction of a visual and thermal overhead inspection programme of $2.8 million in the DPP4 period. This includes a reduction of $1.2 million associated with disestablishing our ABS inspection programme which is now incorporated into the new overhead programme. This programme has been 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 $0.75 million in the DPP4 period.
- Enhanced distribution switchgear inspections to enable deferral of switchgear renewals. This cost declines over time as we progress our switchgear renewal programme. Forecast increase of $2 million in the DPP4 period.
- Introduction of a lidar survey in RY27 and RY29. Forecast increase of $1 million in the DPP4 period.
- $1.8 million of deferred preventive maintenance from the DPP3/CPP period into the DPP4 period.
- Other small step changes including the inspection of consumer poles.

The step changes in Corrective Maintenance account for approximately one half of the 38.9% increase across Routine and Corrective Maintenance expenditure. Most (73%) of this increase is associated with completing the consumer pole programme. The need case for this programme was tested as part of the CPP Determination but due to prioritisation of limited operational expenditure allowance in the CPP period, some of this work will be deferred into the DPP4 period. Note that RY26 is an overlap year between the CPP and DPP4 periods.

1.3.12. Delivery of our plan

To deliver planned maintenance, reactive maintenance, vegetation management, and capital projects, Aurora Energy operates an external contracting model. We have recently concluded extensive competitive tender processes to establish new contracting agreements for both field services and vegetation services. From 1 April 2024, our key service providers operating on the Aurora Energy network will be:

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

We developed a procurement methodology to ensure that our FSA partners have the capability to safely operate and maintain the network in the short- and long-term.

These service 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 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.

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 neighbouring 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 high confidence in our ability to deliver our DPP4 and 10-year period plan.

A

DELIVERING FOR CONSUMERS

CHAPTER 2

WHO WE ARE

Aurora Energy is one of the largest electricity networks in Aotearoa 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 Te Waipounamu, the South Island.

2.1. WHO IS AURORA ENERGY?

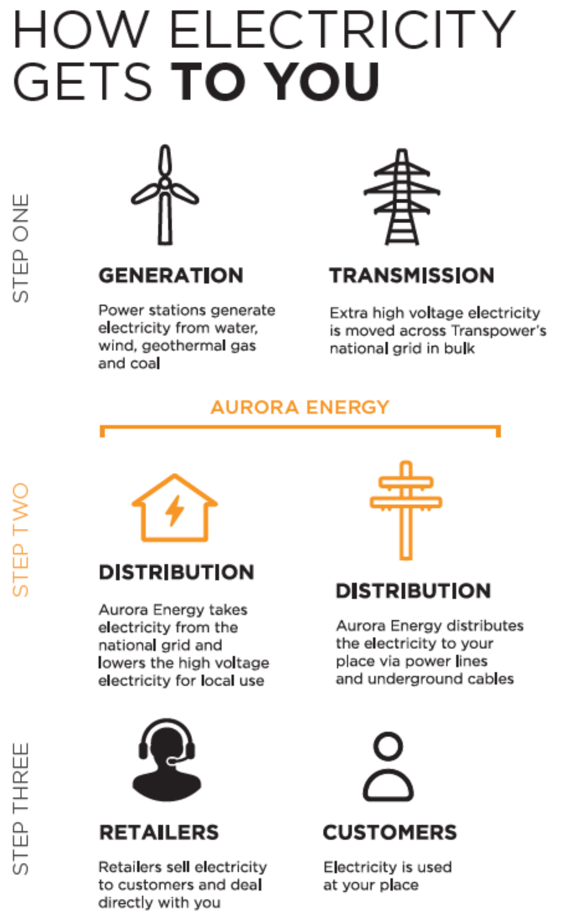
We take the power from Transpower's national grid to power your home, business and the wider community, and deliver a safe, reliable and sustainable electricity supply to more than 200,000 people across Ōtākou in Ōtepoti Dunedin, Central Otago, Wānaka and Tāhuna Queenstown.

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 overall energy costs by actively managing how electricity is used 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 over $500 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 to 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, more than 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 to 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.

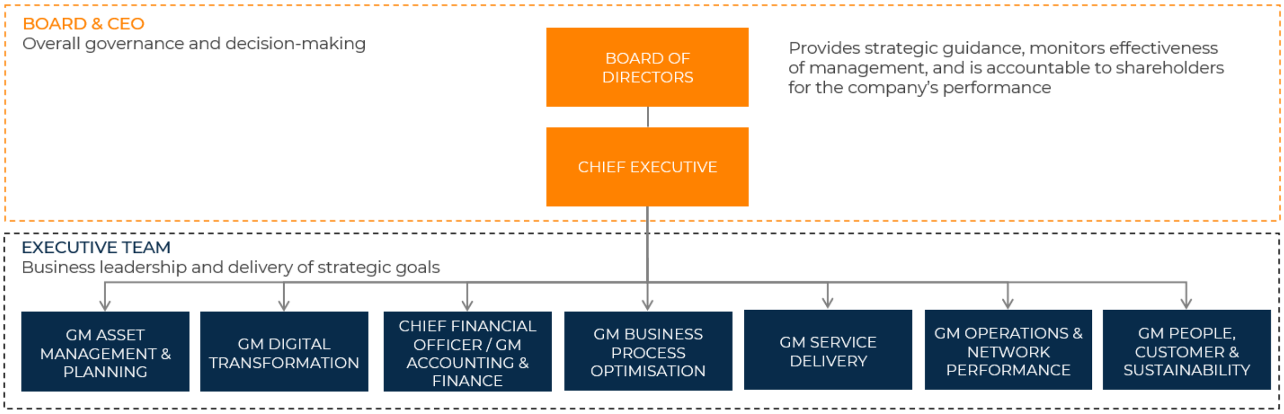
The Board reviews and approves the AMP to ensure it meets all regulatory requirements. This AMP was approved by Aurora Energy's Board on 21 March 2024.

EXECUTIVE LEADERSHIP TEAM

Like most organisations, support is provided by a group of general managers (GM), 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.

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 primary responsibility for the day-to-day management of our network lies with the following teams:

- 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 Aotearoa 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 vision: **Enabling the energy future of our communities**.

Our vision, goal, 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!

Aurora Energy's Asset Management Policy instigates key objectives of Safety, Reliability, Affordability, Responsiveness, and Sustainability. These objectives form the foundation of our detailed strategies in asset management and planning, ensuring that our operational activities are aligned and actively contribute to achieving our overarching corporate vision and mission.

2.3. OUR INVESTMENT DRIVERS

This section gives an overview of the key factors that have impacted on our approach to asset management over the planning period. The focus for Aurora Energy has been on improving safety. A secondary benefit from upgrading and maintaining the network to improve safety is that is it also improves reliability, which we know is important for consumers.

CHALLENGES WE FACE

Table 2-1 outlines the key challenges that impact on 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 three years has been addressing this challenge, but other safety issues such as risk of extreme weather – including wildfires – continue to present challenges for managing the network and we are putting plans in place to address this.
Ageing assets	Over more than a century, our infrastructure has developed alongside population/regional growth. Large portions of our network are now due for renewal. Over the next 10 years we need to make significant investments to maintain and renew our distribution network, as well as preparing for the changing energy needs of consumers.
Growth & demand	Future planning is challenging due to the unknown extent and pace of electrification, 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.
Changing consumer expectations	Consumer needs are evolving due to their uptake of new technologies such as EVs with smart chargers and solar/battery systems. Consumers can now inject generation into the local network, creating a two-way power flow. We need to ensure our network meets 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 01 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.
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 aim to make our assets and network more resilient. We are also developing response and recovery plans 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 electricity is being used by

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 three years has been addressing this challenge, but other safety issues such as risk of extreme weather – including wildfires – continue to present challenges for managing the network and we are putting plans in place to address this.
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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.
	consumers. 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 system, we will have improved data to better inform decision-making and planning. We are progressing towards 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, as well as future workforce planning to ensure Aurora Energy can continue to deliver to a high standard.

PRIORITY INVESTMENT DRIVERS

Based on our key challenges above, we have developed our priority drivers for investment 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

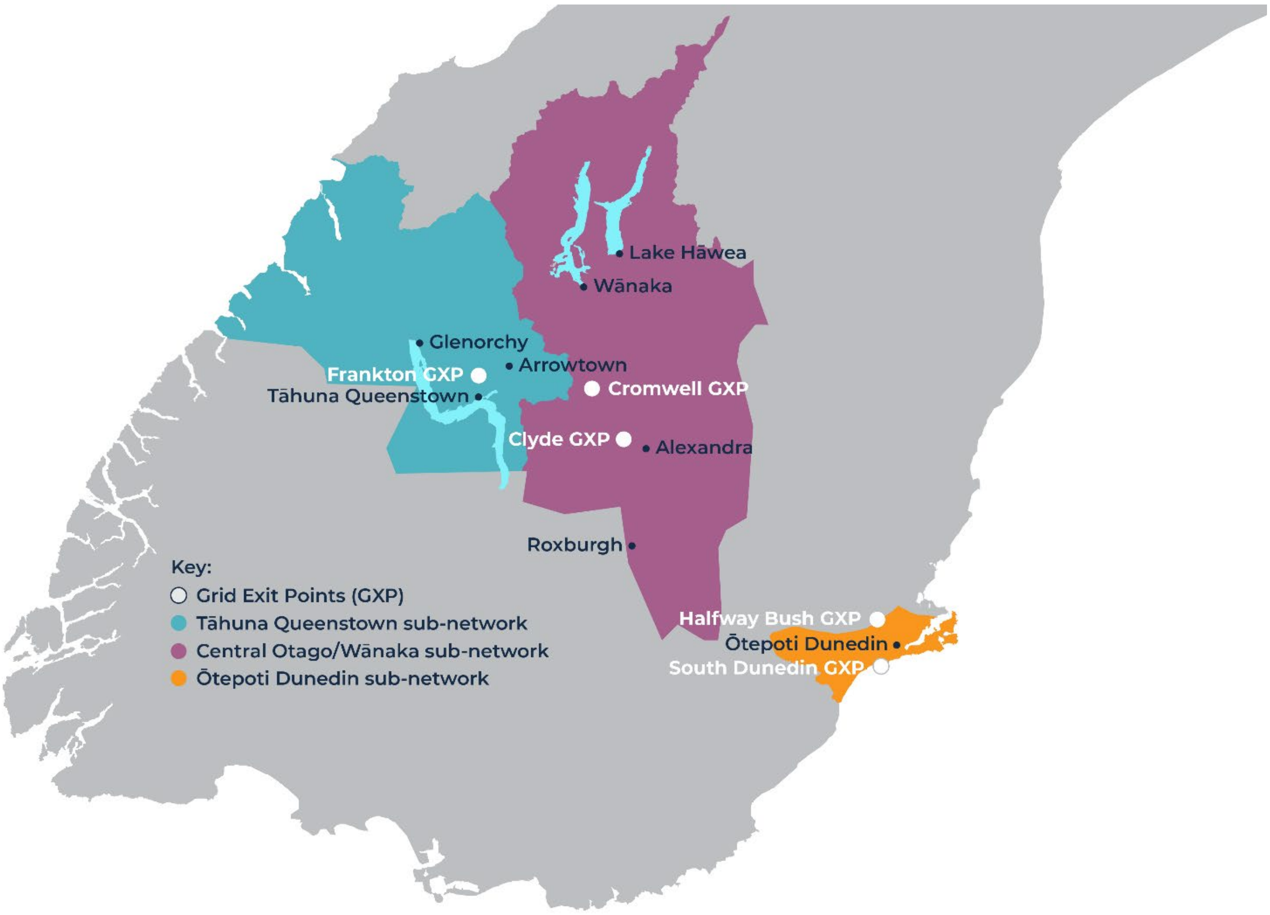
Strategic Focus Area	Investment driver	Description
Our People	Asset safety	People come first. It's top of our list because we care about the safety and wellbeing of our people and communities. That makes safety of the assets our uncompromised objective.
Future Network	Growth and demand	Uncertainty around 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 ensure a reliable electricity supply.
Customers & communities	Changing consumer expectations	Listening to what consumers want from an electricity network will ensure we meet their needs. This is increasingly important as the way people use electricity changes 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	Asset renewal, maintenance and condition assessment to reduce backlogs of poor condition assets are 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 enables 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 GXPs for our Central Otago & Wānaka sub-network and one GXP for our Queenstown sub-network. The number of customers distributed across these GXPs is summarised in Table 3-1.

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

Table 3-1: GXP and sub-network

Sub-network	GXP	Number of customers	% of customers
Dunedin	Halfway Bush	35,500	38%
	South Dunedin	21,100	22%
Central Otago & Wānaka	Clyde	7,700	8%
	Cromwell	15,500	16%
Queenstown	Frankton	14,900	16%

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

3.1.2. Network configuration

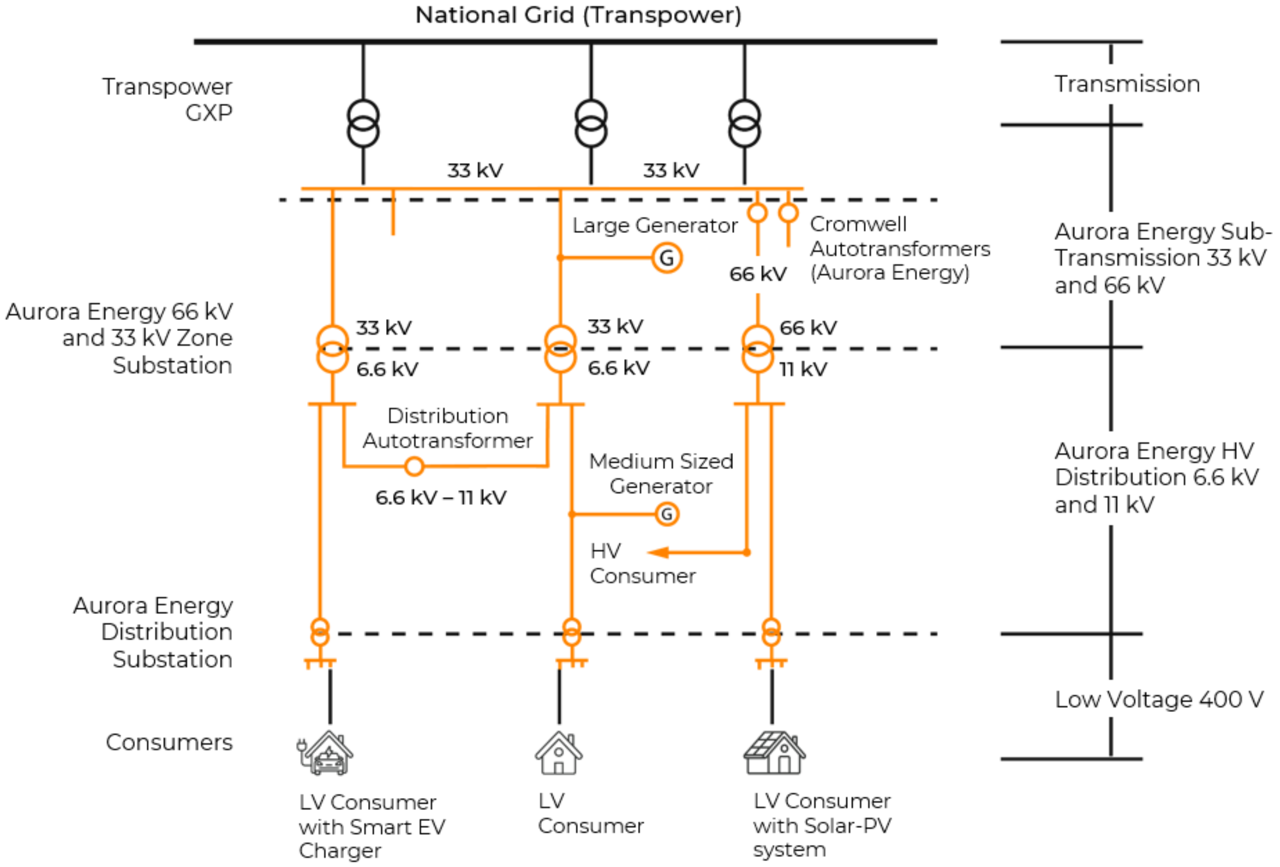
Our network is hierarchical in nature, with lines and cables operating at three distinct voltage ranges:

- **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	—	—	—	94,700
Overhead network	523 km	2,285 km	1,028 km	3,836 km
Underground	89 km	1,195 km	1,136 km	2,420 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	—	—
Protection relays	Yes	Yes	No	Yes
SCADA and metering	Yes	Yes	Yes	Yes
Structures and air break switches	Yes	Yes	Yes	Yes
Other	33 kV cable gassing bank	33 kV cable oil reservoirs	—	Two 30 MVA 33/66 kV auto-transformers

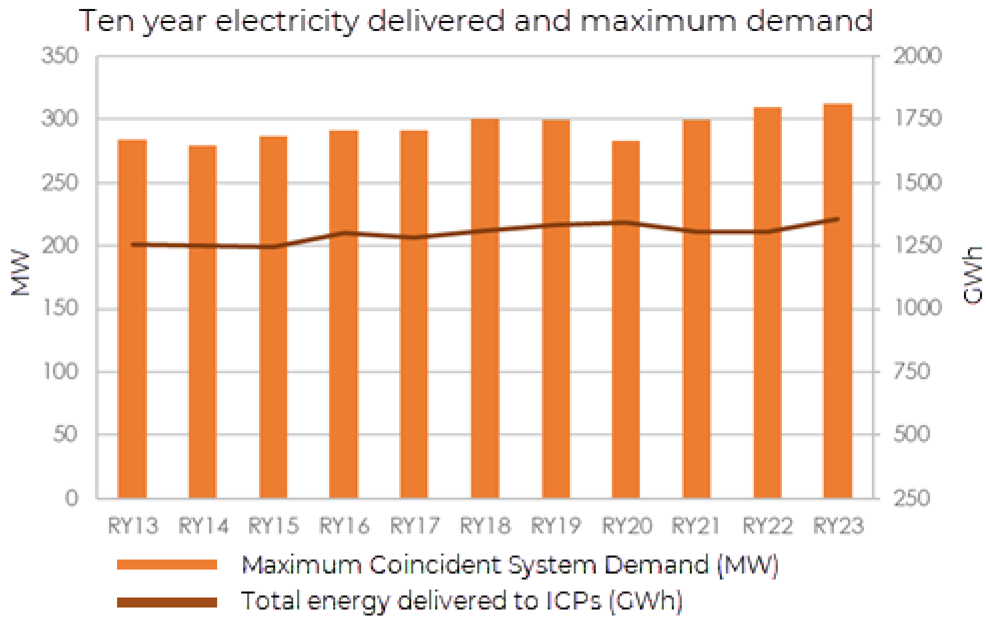
3.1.4. Total system peak demand & energy throughput

The total system peak demand and electricity delivered has progressively increased from RY20 (Covid-19) to 313 MW and 1356 GWh in RY23. This indicates that the network is growing to meet consumers' needs.

Much of this growth is in Wānaka and Queenstown, while the load on our Dunedin and Central Otago & Wānaka sub-networks is increasing at a modest pace.

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 last year's GXP peak demand, energy throughput with Zone Transformer capacity and the number of Zone substations.

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

Sub-network	Maximum demand (MW)	Energy throughput (GWh)
Dunedin	189	783
Central Otago & Wānaka	68	313
Queenstown	64	259

Table 3-5: Peak demand and firm capacity

GXP	Sub-network	Maximum demand (MW)	Firm capacity (MW)	Zone transformer capacity (MVA)	Zone substations (Qty)
Halfway Bush	Dunedin	121	135	364	22
South Dunedin	Dunedin	73	108	266	12
Cromwell	Central Otago & Wānaka	49	58	119	8
Clyde	Central Otago & Wānaka	19	27	50	8
Frankton	Queenstown	72	74	164	14

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.

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 Interim Guide for connection of small-scale inverter-based DG. Small-scale DG are typically 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 DG 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 2023, the total installed generation capacity was 147 MW (47% of system maximum demand). Figure 3-5 shows the proportions of each type of generation.

Figure 3-5: Generation by type

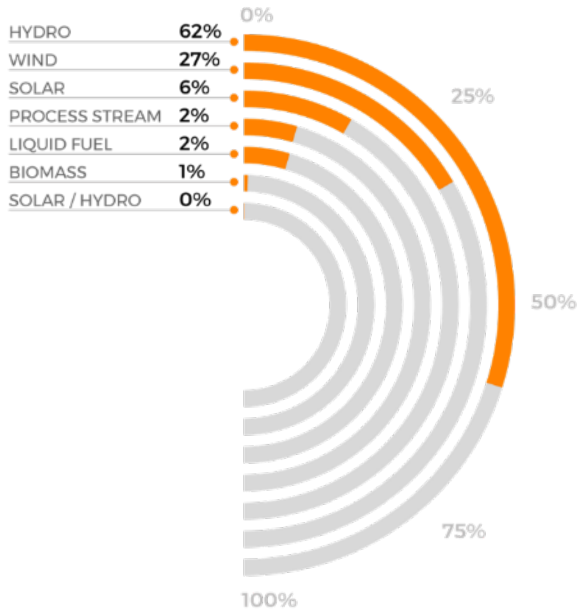


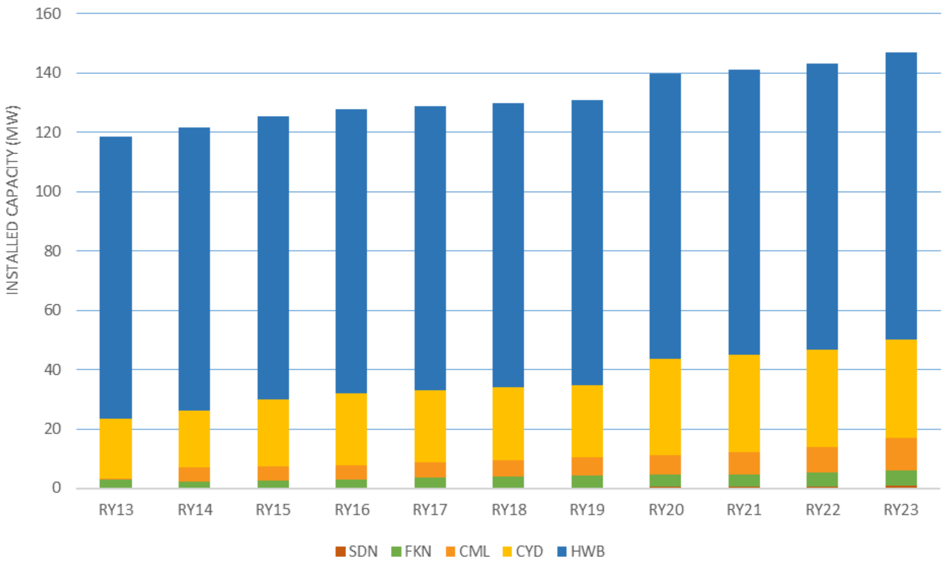
Table 3-6 gives a list of large, embedded generation (>1 MW) and Figure 3-6 shows the uptake of generation per GXP over 10 years.

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	94.6
	Waipori 33 kV - Mahinerangi	Wind	36	
	Ravensdown generation	Process steam	3	
	Container Port (Port Otago)	Liquid fuel	1.6	
	DCC wastewater treatment plant	Biomass	1	
South Dunedin	—	—	—	—
Clyde	Teviot stations	Hydro	12.3	32.0
	Earnscleugh station	Hydro	7.9	
	Horseshoe Bend	Hydro	4.3	
	Fraser Generation	Hydro	3	
	Horseshoe Bend Wind	Wind	2.3	
	Talla Burn	Hydro	2.2	

GXP	Name	Type	Capacity (MW)	Total per GXP
Cromwell	Roaring Meg	Hydro	4.3	5.3
	Devon Dairy	Solar	1	
Frankton	Wye Creek	Hydro	1.7	1.7

Figure 3-6: Total generation uptake per GXP

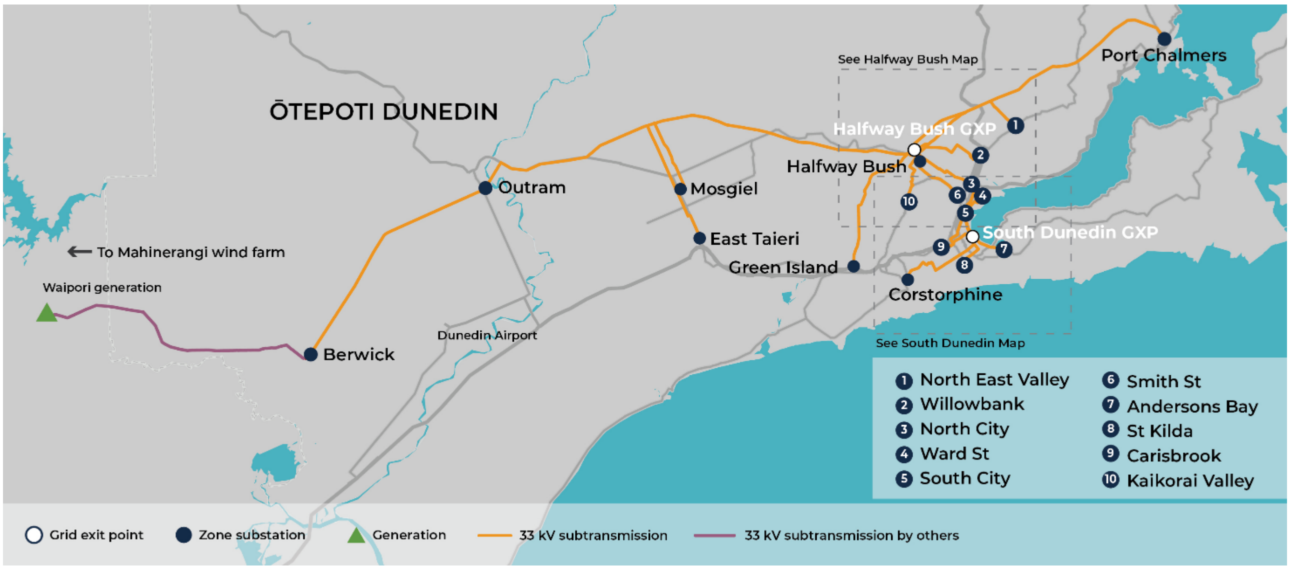


3.2. DUNEDIN SUB-NETWORK

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, most of Dunedin's 33 kV subtransmission is radial, where each zone substation is fed directly from the 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. Aurora Energy have installed autotransformers to link the 6.6 kV network with the 11 kV network. The distribution network is made up of overhead lines and underground cables, whereas the CBD is mostly underground cables.

Halfway Bush GXP has a large embedded generation plant (Waipori) that supplies 30% of the GXP's peak demand. The Waipori generation has a total generation capacity of 96 MW (hydro and wind). South Dunedin GXP has no large embedded generation.

Figure 3-8: Halfway Bush subtransmission and zone substations

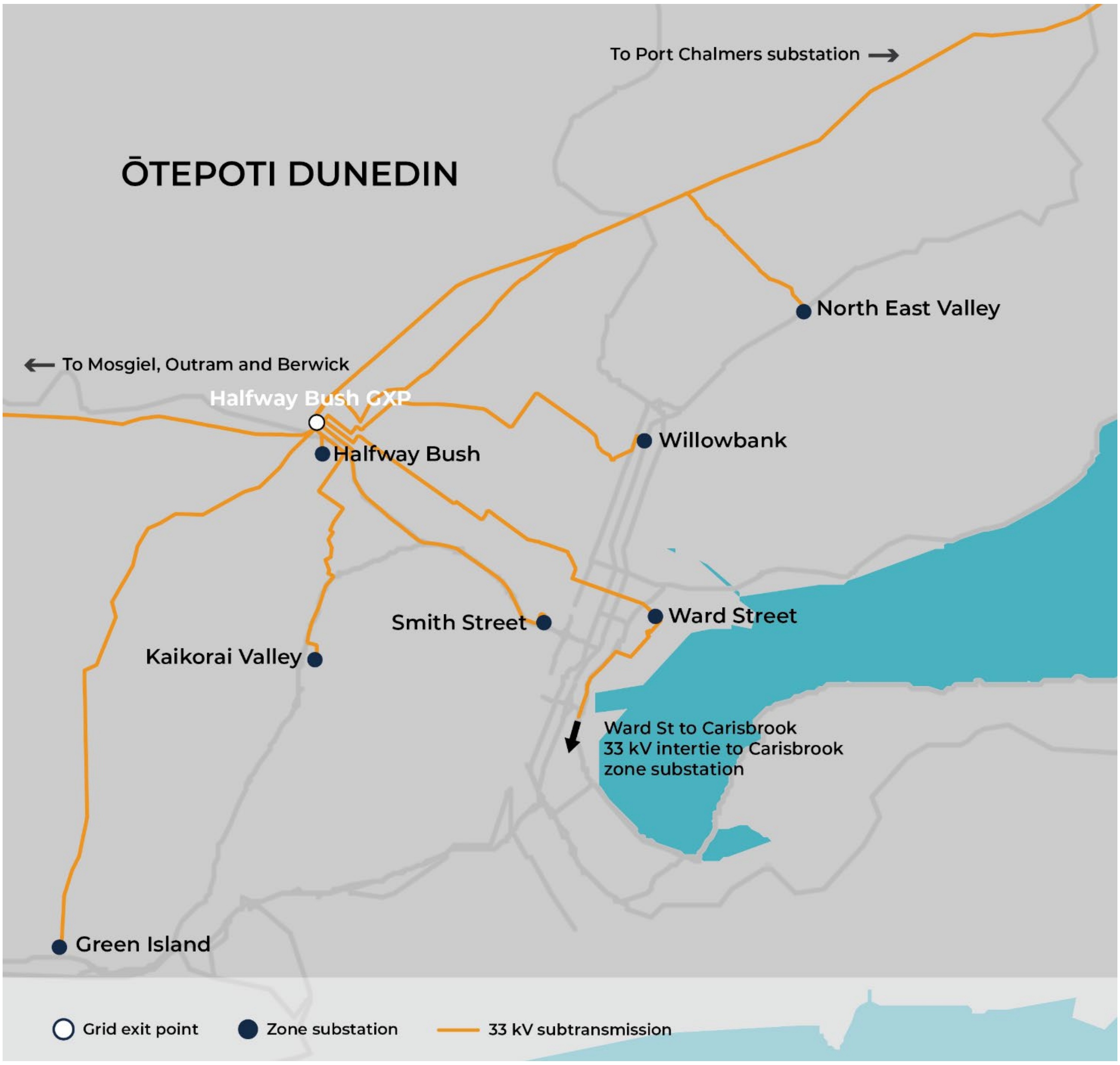
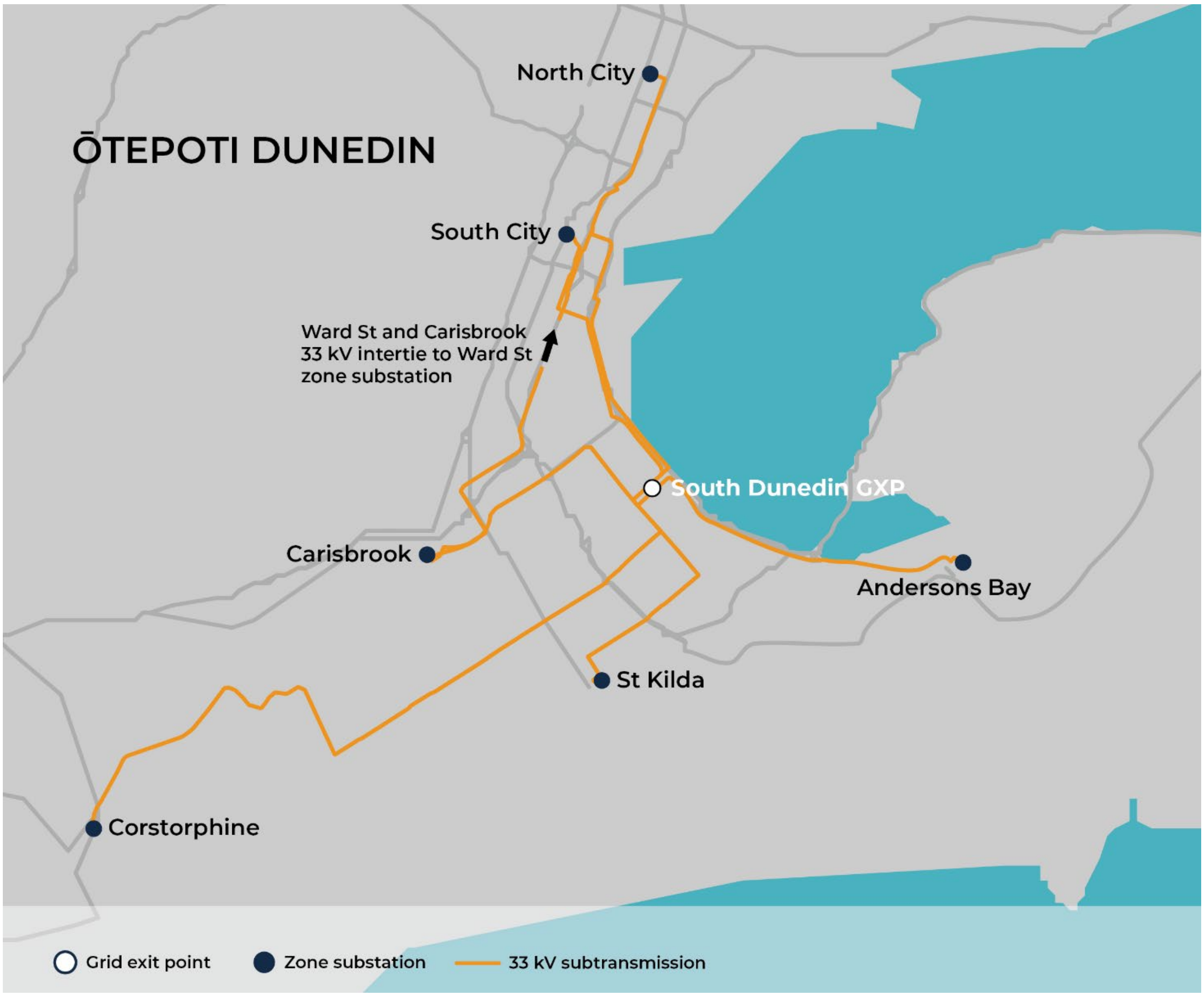


Figure 3-9: South Dunedin subtransmission and zone substations



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 and 66 kV	6.6 kV and 11 kV	400 V and 230 V	Total
Zone substations	—	—	—	18
Distribution transformers	—	—	—	2,700
Consumer connections	—	—	—	56,600
Overhead network	144 km	730 km	809 km	1,683 km
Underground network	66 km	332 km	310 km	708 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-occupied accommodation – reduces over the university holiday periods. There are a number of alternate supply possibilities into the university area from North City, Ward Street, Willowbank and Smith Street zone substations.
Port of 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, they will be supplied through shore power substations that provide electricity to a vessel when 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. Each sub-network is 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 consists of the Wānaka, Cardrona and Hāwea areas.

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 with 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; however, 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 and 66 kV	6.6 kV and 11 kV	400 V and 230 V	Total
Zone substations	—	—	—	13
Distribution transformers	—	—	—	3,300
Consumer connections	—	—	—	23,200
Overhead network	309 km	1,271 km	174 km	1,754 km
Underground network	10 km	573 km	510 km	1,093 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

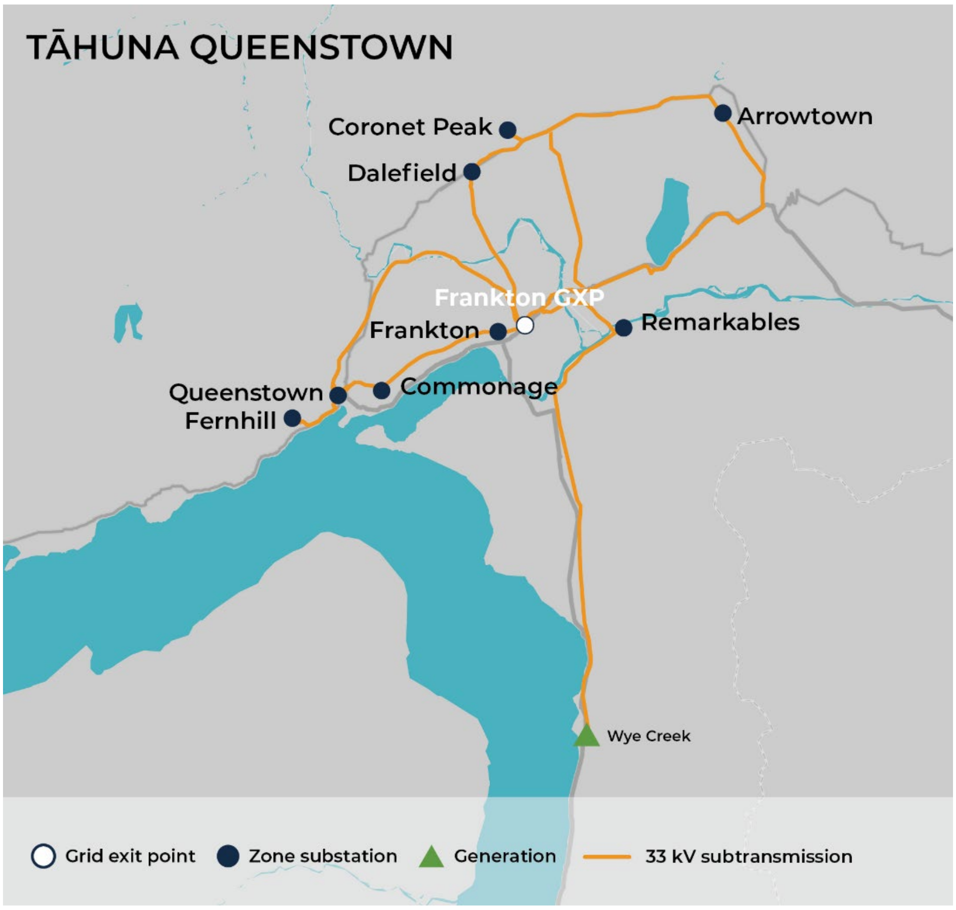
Consumer	Description
QLDC and CODC local councils	The total load of the Central Otago District Council (CODC) and Queenstown Lakes District Council (QLDC) sites is significant. As in Dunedin, the most important loads are those associated with water and wastewater pumping and treatment. Most of the CODC 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.
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 visitors will spur development of accommodation, and hence increased electricity demand.
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.
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.

3.4. QUEENSTOWN SUB-NETWORK

The Frankton GXP is supplied through 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, which supplies the substations in the Whakatipu Basin; and the Queenstown circuit, which 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 and 66 kV	6.6 kV and 11 kV	400 V and 230 V	Total
Zone substations				8
Distribution transformers				1,300
Consumer connections				14,900
Overhead network	69 km	284 km	45 km	398 km
Underground network	13 km	290 km	315 km	618 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 demand on all zone substations in the sub-network peaks during winter.

3.4.3. Key consumers

Our key consumers for the Central Otago & Wānaka sub-network are summarised in Table 3-12.

Table 3-12: 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. 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 increase in 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 amount 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 schedule. A large fleet of rental cars is stationed near the airport. As these transition to EVs, growth in charging load is expected.
Coronet Peak and Remarkables Ski Fields	Load at these sites includes ski lifts and snow-making machinery, and 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. Ski field 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

Our stakeholders and consumers are at the centre of 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 & THEIR INTERESTS

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

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 Reliability of supply Contractual arrangements How we manage consumer complaints Ease of doing business with us	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
Government agencies **City, district and regional councils**	Waka Kotahi the New Zealand Transport Agency Dunedin City Council Central Otago District Council	Public safety Environmental protection Support for economic growth Control of assets in road reserves	Direct communication Submissions RMA applications

Stakeholder group	Description	Key interests	How interests are identified
	Queenstown Lakes District Council Dunedin City Council Otago Regional Council		
Property developers	Acquire and enhance land and properties	New connection policies and costs Switching off power during relocations	Direct communications
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
Media	Print, online and radio channels used to broadcast to the public	News	Direct communication

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.

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. Delivering a safe, reliable and affordable electricity supply 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 and 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 over 99% of the time.

4.2.1. Customer charter

Aurora Energy's Customer Charter and compensation scheme was first developed in 2017 and since then our organisation has matured, with more emphasis on listening to and meeting the needs of consumers. We are in the process of updating the commitments we are making to reflect what consumers have told us they want and ensure the commitments are measurable across the business. Public engagement took place in November 2023 and, at the time of writing, the proposed changes are still to be analysed and approved.

If the public supports the proposed changes and they are certified by the Board, the new documents under the Customer Charter will be the Customer Commitments and Customer Service Standard Payment Scheme. They will outline our service levels, what consumers can expect from us and what we need from them, and what compensation we will provide if we fail to meet certain 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. We look forward to having a comprehensive data set for comparison following a full survey as well as the longitudinal panel survey in 2024.

ENGAGING DIRECTLY WITH CONSUMERS

Two-way conversations with consumers on the Aurora Energy network allow us to not only gain valuable feedback but also 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, and in some instances arrange for a local hall to be available in more isolated communities so people have somewhere to go to charge devices and use bathroom/kitchen facilities while the power is out at their property.

We also have a project to identify 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 what work we have done or have planned to improve their electricity supply.

WHAT CONSUMERS HAVE TOLD US

Results from the 2022 benchmark customer satisfaction survey have informed Aurora Energy's Customer and Engagement Strategy, the proposed new Customer Commitments and Customer Service Standard Payment Scheme (Customer Charter), and Customer Outage Guidelines that are used to minimise consumer impact when planning work.

Figure 4-1 shows a snapshot of outcomes from our 2023 customer satisfaction survey, while actions that are already underway or that we plan to take as a result of the customer satisfaction surveys are outlined in Table 4-2.

Figure 4-1: 2023 Customer satisfaction survey outcomes

Performance and CPP metrics

34%
Rate performance as good, 32% neutral, 23% unsure, 11 % poor

12%
Know 'a lot' or 'a little' about the maintenance programme (e.g. pole replacements/sub-station upgrades)

9%
Know 'a lot' or 'a little' about the 5-year investment plan

Improving confidence

What customers want

- Complete works as planned; show proof plan is being implemented
- Communication that is local; multichannel and more of it
- Outline the programme
- Network reliability

Just under a third already own an EV or solar panels or are interested

Communications

23%
Heard 'a great deal' or 'a moderate amount'; 30% occasionally

What: Mainly pole and line replacements/upgrades and notice of planned outages

Where: Direct mail, local community newspaper, social media

48% prefer the status quo regarding infrastructure plans and how they are paid for, **23%** are willing to pay more for fewer unplanned outages

Table 4-2: Customer satisfaction survey results and outcomes/actions

Key feedback themes	Outcomes/actions
52% of respondents had read, seen or heard about Aurora Energy in the last year either occasionally, a moderate amount or a great deal.	Continue our communications and engagement programme as it is proving effective, and continue monitoring results. Upcoming: a new public safety advertising campaign, text notification of power outages, increase the number of proactive media statements.
The survey results gave us tips on how to increase confidence in Aurora Energy's ability to deliver the maintenance programme and five-year investment plan: • Completing the works as planned • Communication (more comms, local info and multiple channels) • Outlining the works programme.	Continue to have tailored communications in each pricing area, continue with community relations programme and continue with reliability hotspots project. Upcoming: Include more consumer benefits of the work being done in communications, launch 'Your Network, Your News' (six-monthly newsletter that is inserted into community newspapers around Otago) as an e-newsletter to broaden the reach.
Low knowledge of maintenance programme and five-year investment plan.	Anticipate an increase next year following ongoing proactive communications and introducing new initiatives such as e-newsletter, more media statements and ensuring we outline more benefits to consumers of the work being undertaken.
Low knowledge of customer charter.	Expect this to increase next year, following consultation and launch of new customer commitments (pending approval).
Low knowledge of how lines charges are set.	Expect this to increase next year, following increased pricing comms, including time of use.

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/meeting the needs of consumers will help us achieve Aurora Energy's vision to enable the energy future of our communities.

We accommodate stakeholder interests into our asset management practices in several areas as outlined in Table 4-3.

Table 4-3: How we accommodate stakeholder interest 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 • 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 deliver on our promise to upgrade the network.
- Public safety campaign/communications – a new campaign will be launched in 2024 that will target safety messages more effectively and aligns with the Aurora Energy brand and narrative.
- A new website was launched in 2023 that provides a better user experience, based on user research.
- 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.
- Improved outage information following a new outage management system being implemented alongside the new website has improved accuracy, timeliness and how outage information is displayed.
- Development of a brand narrative to help consumers better understand who Aurora Energy is and what we do – completed in 2023 with a rolling launch.
- Community relations programme – 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. It is clearly communicated across a range of channels that consumers can seek advice from Utilities Disputes if they are unhappy with the response that they receive from Aurora Energy. Processes are being implemented to review complaints more effectively to identity potential themes where improvements to systems, processes or customer service can be made.

4.3.1. Dunedin sub-network

With over 56,500 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 to provide a reliable electricity supply. There are just over 23,000 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 about resilience and capacity. Access to parts of this network can also be challenging due to the rugged terrain and environmental significance. Consumers want reassurance Aurora Energy is working alongside Transpower and the local Council to plan for energy resilience. The Queenstown Lakes network has just under 15,000 ICPs but a peak tourist population of over 110,000 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 the relocation of an existing asset).

Aurora Energy certify and authorise '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 design and build 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, large industrial building, 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 >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 <10 kW) to the Aurora Energy distribution network.

Further information about new or altered 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 sustainable, secure, affordable and efficient energy supply is important to consumers, people and environment. That's why we are committed to working with our communities in new ways to support the energy choices they make, and to manage our business so we can contribute to a sustainable energy future. For Aurora Energy, this is anchored in clear actions.

Service levels help us to ensure that 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.

Service levels cover our core business areas. They align with Aurora Energy's overall strategic focus areas, which helps to 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 & PUBLIC SAFETY

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

Performance Target: We target zero incidents of public harm. Total Recordable Injury Frequency Rate (TRIFR) is 3.50 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 total recordable injury frequency rate (TRIFR) towards a best practice performance level of 3.5 or better. Zero public harm is our ultimate commitment, and our target for public safety incidents and specifically harm to any member of the public is zero.

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			
		2020	2021	2022	2023
Actual harm to public	0	1	2	0	0
TRIFR	<3.50	5.20	5.40	5.10	4.20

SAFETY CRITICAL ASSETS

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

Performance Target: Cast iron pothead cable terminations removed from service in 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 by the end of RY26. Table 5-2 sets out our CIPH removal progress to date.

Table 5-2: CIPH removal

Target area	AMP20	AMP22	AMP23	AMP24
Remaining CIPH	400	250	165	100

We have 100 cast iron potheads remaining on the network and we are on track for our RY26 target. For further discussion, see Section 11.7.

In our 2018 AMP, we identified the need to reduce our backlog of red-tagged poles which was over 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 December 2022 sat at 674. We have a target of RY24 to reduce the backlog. See Section 11.1 for our renewal priorities for our poles fleet.

5.1.2. Reliability

Service Level: Ensuring 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 of interruptions per customer and their duration. Major factors in determining levels of 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 our reliability, such as poor 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; 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, number of customers affected, and 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 Commission.

More information on reliability targets is provided in Appendix D.

Table 5-3: Historical performance (unplanned reliability)

Target area	Historical Performance				
	RY19	RY20	RY21	RY22	RY23
SAIDI Unplanned Target	111.00	103.00	146.29	124.94	124.94
SAIDI Unplanned Actuals	98.14	109.90	85.39	98.45	106.45
SAIFI Unplanned Target	2.05	1.90	2.51	2.07	2.07
SAIFI Unplanned Actuals	1.53	1.59	1.46	1.50	1.75

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.

Our reliability forecasting methodology was established as part of our CPP application, and it utilises historical performance and our planned work programme to estimate future performance through the planning period. In forecasting unplanned SAIDI and SAIFI, we estimate how our safety driven asset maintenance and renewals programmes will improve the overall health and performance of asset fleets.

On a monthly basis, we monitor unplanned reliability performance against our target values. This approach provides early identification and follow-up actions when we identify a risk of exceeding our targets.

As mentioned in Chapter 4, we have a 'reliability hotspots' project underway. We undertake proactive communication with consumers in areas of the network where reliability is lower than our expectations, to let them know we have a spotlight on their area and what we are doing to address performance.

Through the CPP Period, we have targeted network investment towards improving the safety of our asset fleets. We have not specifically targeted improvements in reliability, but we do expect to see some improvement over time. Beyond the CPP, we will reassess our reliability performance goals based on consumer preferences. Performance for each sub-network is provided in Appendix D.

Figure 5-1: SAIDI – Unplanned Performance

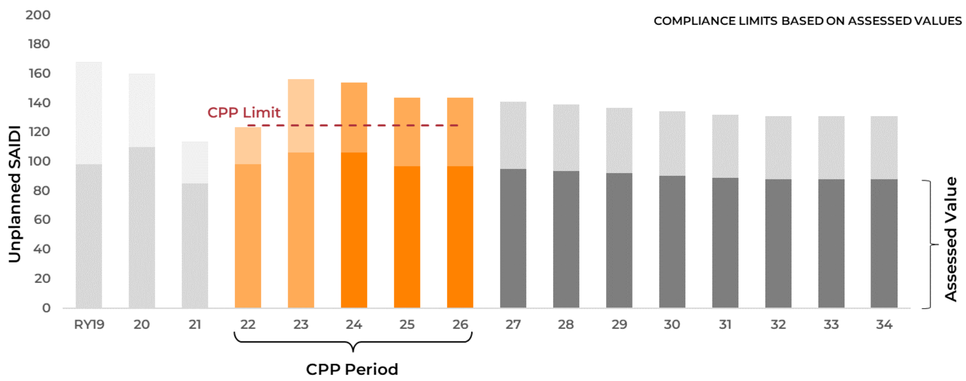
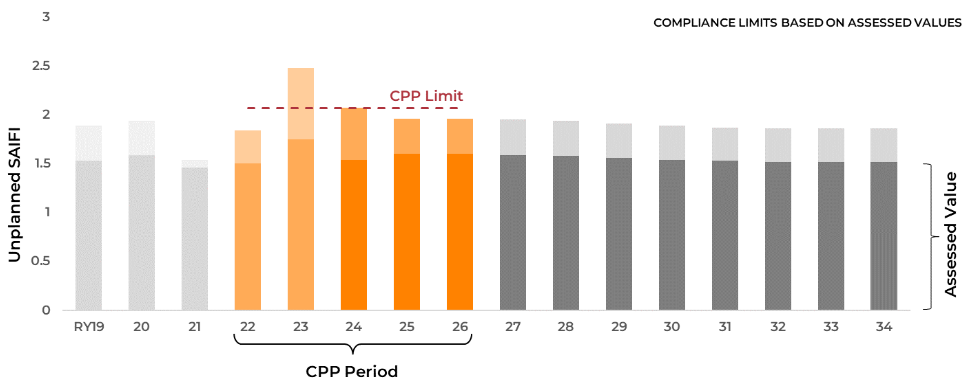


Figure 5-2: SAIFI – Unplanned Performance



A SAIFI level of 2.0 indicates that the average consumer across our networks experiences two unplanned outages per annum. Due to changes in reporting methodologies, it can be difficult to interpret the change in performance over time, but our analysis concludes a stabilisation or slight improvement in performance since expenditure on the network was increased from 2018. The slightly higher number of outages in the year ending March 2023 was caused by a small number of large outages that we have since rectified. At the time of drafting this AMP the year ending March 2024 was tracking well with an anticipated result commensurate with our forecast for 2024.

PLANNED PERFORMANCE

While we understand the need to keep the power on as often 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 several 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 on the network to address historical issues with the condition of our network. In RY19–20, we exceeded some of our target values for planned performance. In RY21, we revised our planned reliability targets to align with the limits set for us by the Commerce Commission. For this period, our planned SAIDI values have been calculated using a different approach which allows us to reduce the SAIDI impact for outages where proper notification processes have been followed.

Our forecast for planned reliability utilises information from our planned expenditure to estimate the potential impact of all programmed works during the year. Our forecasting indicates a reduction over time in the customer impact from planned outages.

We have undergone a period of intensive expenditure on our network in recent years to improve asset condition. Over the planning period, we expect that this need will reduce.

Performance for each sub-network is provided in Appendix D.

Table 5-4: Historical performance (planned reliability)

Target area	Historical Performance				
	RY19	RY20	RY21	RY22	RY23
SAIDI Planned Target	146.00	116.00	195.96	195.96	195.96
SAIDI Planned Actuals	154.30	110.71	102.73	124.5	110.34
SAIFI Planned Target	0.72	0.51	1.11	1.11	1.11
SAIFI Planned Actuals	0.73	0.61	0.68	0.83	0.60

Figure 5-3: SAIDI – Planned Performance

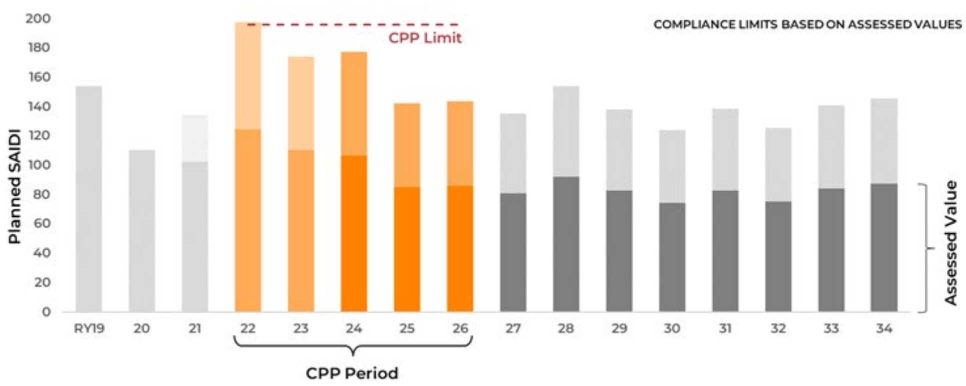
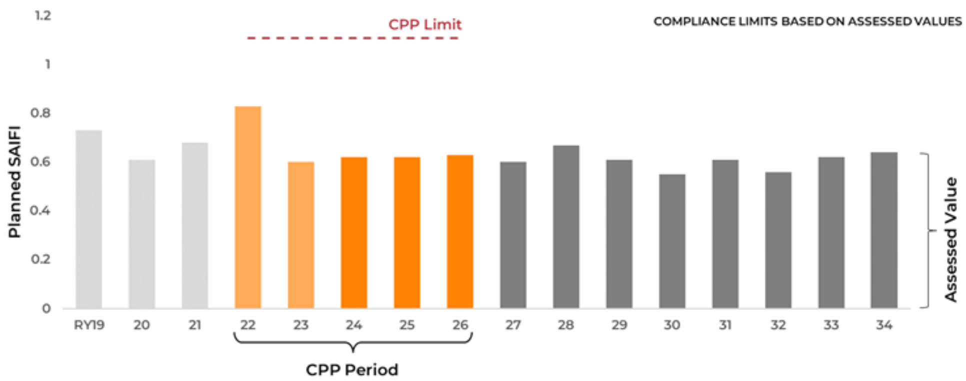


Figure 5-4: SAIFI – Planned Performance



5.1.3. Customer service

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

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

POWER QUALITY COMPLAINTS

As part of our ongoing development plan, we are focused on improving our visibility and our 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 queries. We have set ourselves stage gate targets to respond to each query, perform our analysis, and resolve the query. We have been collecting performance data since 2020 (see Table 5-5).

We have seen significant progress in all three target areas since we began our performance tracking.

Our average response time for enquiries is generally less than one day, with only four complaints in total exceeding the seven-day target (zero in 2022 and 2023). In 2023, we have also achieved our target of 40 days for average resolution times.

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. Refer to Section 4.2 for more information.

CUSTOMER CHARTER

Aurora Energy is updating our Customer Charter, which outlines service commitments, what consumers can expect from us and how we will compensate them if we fail to meet certain commitments. Refer to Section 4.2 for more information.

Table 5-5: Timeframes for responding to power quality complaints

Year (Calendar)	Average Response Time	Average Analysis Time	Average Resolution Time
Target	**7 days**	**20 days**	**40 days**
2020	2.94	48.77	68.58
2021	9.45	55.14	55.14
2022	0.57	22.17	42.22
2023	0.45	22.96	38.91

5.2. FUTURE-FOCUSED SERVICE LEVEL TARGETS

Our traditional target service levels include 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 that the following requirements are met:

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 around how we set targets to ensure that 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 that we have the right information to accurately monitor our performance against each target value without over-burdening our resources.

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

During 2024/25, we propose to expand on our traditional service levels to reflect the changing landscape and the progress we have made to date on our foundational services. We aim to base our prospective performance targets around our five key strategic focus areas. In doing so, we can ensure alignment between stakeholder needs and our internal asset management objectives.

Table 5-6: Future service levels aligned with 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 that 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.	In a recent update to our outage management system (OMS), we have 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 will take effect from 1 April 2024 as part of our updated Field Services Agreement with our fault services crews.
Customers & Communities – Focusing on what matters to customers and partnering with local business and stakeholders to support regional growth	
Customer Satisfaction – Ensuring that we identify what matters to consumers and aligning our service offerings to their expectations.	We conduct regular customer satisfaction surveys (see Section 4.2), and are in the process of establishing target metrics across a range of customer focus areas.
Planned Reliability – We have undergone significant work to improve our processes for notifying consumers around planned outages and for 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 that 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 – Our continued license 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 shareholders and customers	
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 to ensure that 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 make sure 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 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, and others who we outsource asset-related activities to, including service providers and contractors. Ultimately, our asset management framework includes 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 we reach greater maturity with our asset management framework, we will continually review and update key processes and documents to reflect any improvements. Our planned expenditure is reviewed annually to take account of improvements in our decision-making processes.

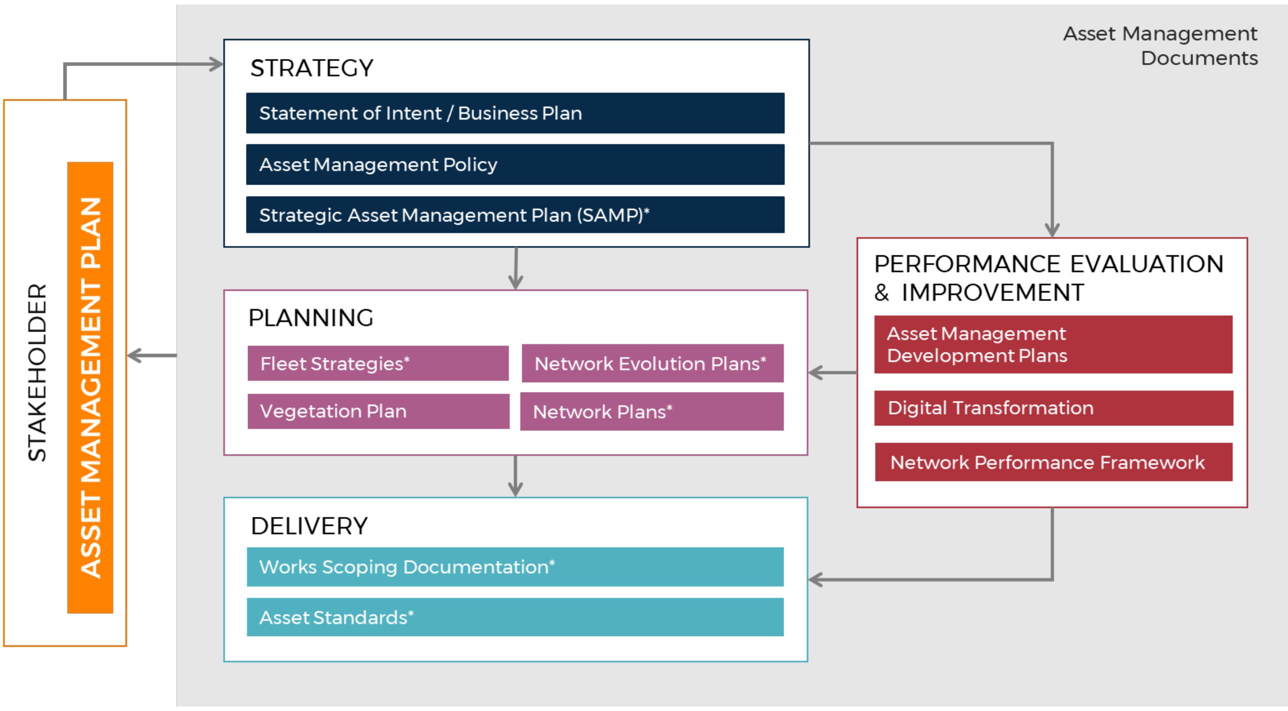
We have not conducted a formal audit of our asset management system since late 2019. This, however, does not mean we have not continued working on further improvement. In our Asset Management Improvement Plan as part of our CPP ADR, we outlined several initiatives to improve our practices. We are currently 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 clear alignment 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	Documents	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 2024; 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 2023; updated annually
	Business Plan	Sets out our business direction over the 2021-25 period, and the key outcomes that we aim to deliver over this period. The plan also provides financial forecasts over the period.	Published 2021
	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 set of processes and decisions required to develop a set of planned expenditure that best meet 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 to our capacity to deliver.	In development
Planning	Fleet Strategies	Reflect our asset lifecycle model and set out how these processes and activities are applied to individual asset fleets.	In development

Level	Documents	Description	Status
	Network evolution plans	Identifies changes to the network enabled by new technology and/or required by changing consumer behaviour or expectations.	In development
	Network plans	Identifies 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.	Three-year plan in place since April 2022.
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).	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 for the way we will 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:

- Take all reasonably practicable steps to protect all people affected by our assets and asset management activities
- Use robust processes and improved asset data to make asset management and lifecycle decisions, balancing cost, risk and performance
- Understand and meet consumers' and stakeholders' needs and values, including iwi and environmental agencies to align our decisions to our understanding of their balanced needs and values
- 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. They derive from our Asset Management Policy to:

- Guide how our organisational objectives are related to our day-to-day activities
- Provide context for internal and external issues that may affect our ability to achieve intended asset management outcomes
- Provide clarity on 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 that activities, such as network development projects, can be prioritised and are aligned with Aurora Energy's vision.

To ensure consistent alignment in 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

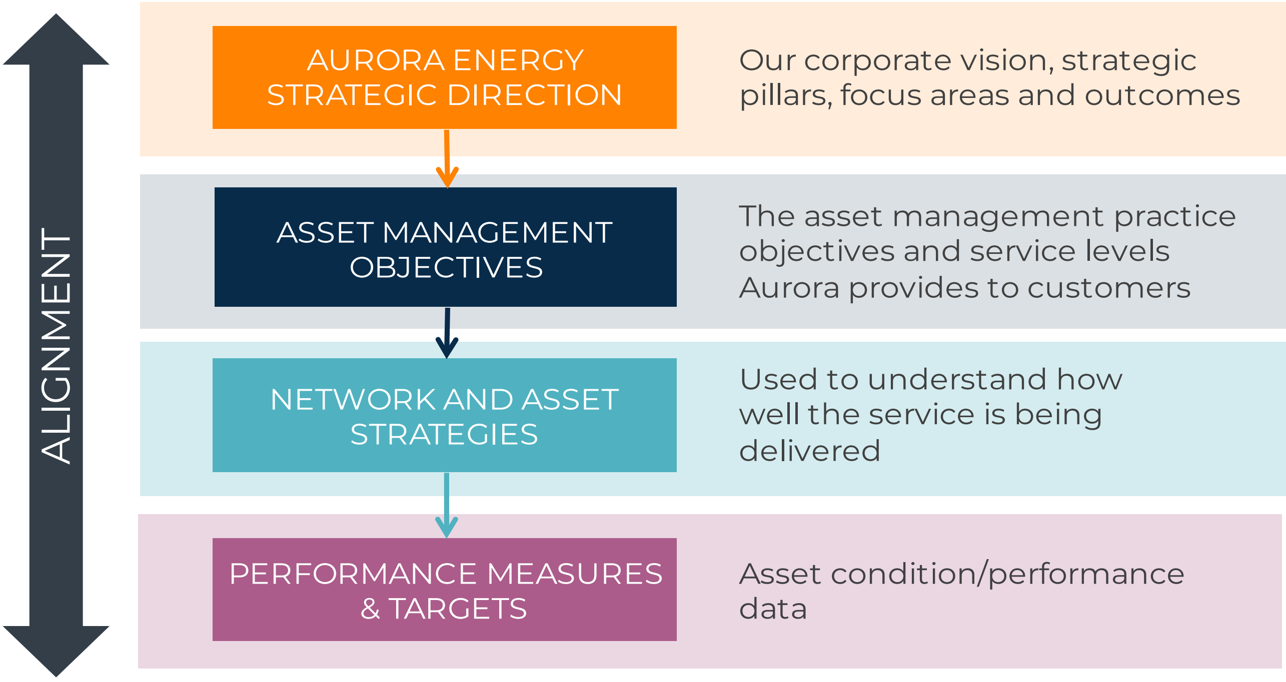
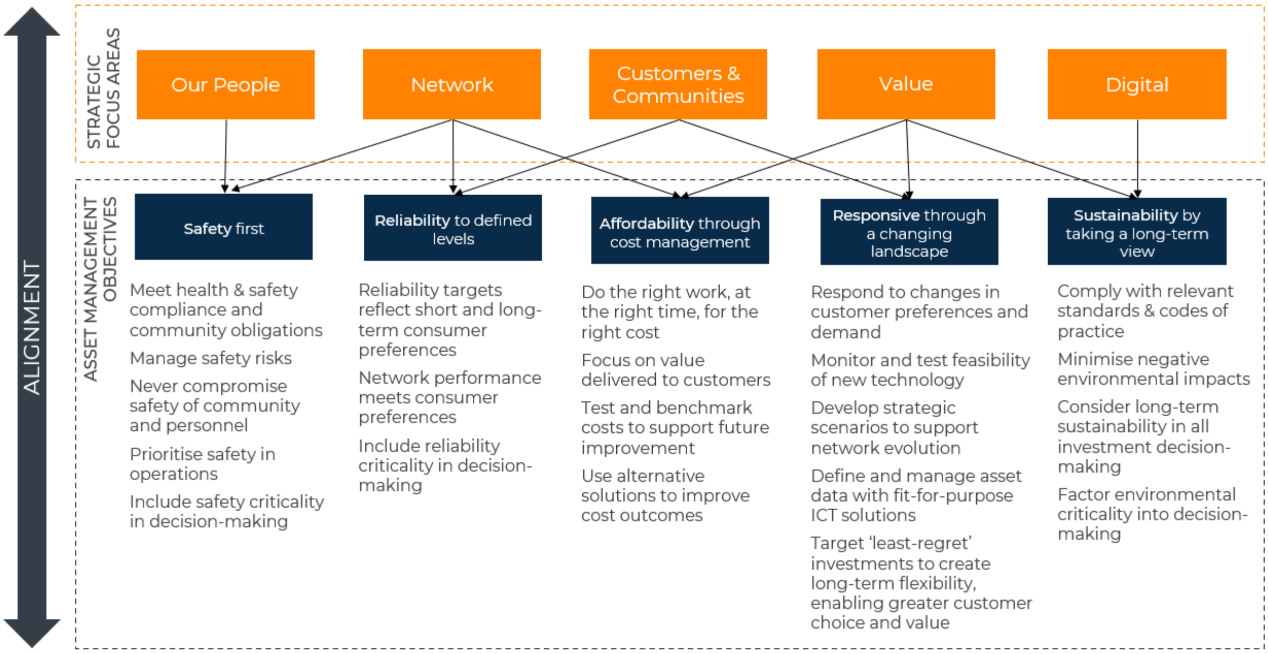


Figure 6-4: Strategic Focus Areas Linked to Management Objectives



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 sufficiently managed. Asset health and condition is linked to likelihood of failure, and for some assets, failure can lead to negative consequences. Public safety risk is greatest for asset classes 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 asset replacements and renewals are made, the corresponding improvement in risk is calculated. 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 have also introduced a Safety Delivery Plan which outlines our approach to reducing safety risks across our network.

KEY STRATEGIES & INITIATIVES

We aim to deliver our safety objectives through the following initiatives:

- Continue to analyse asset risks by safety consequence and defining adequate controls, including review of ICAM and root cause analysis findings against existing risk analyses
- Continue implementing our safety-in-design process
- Prioritise our asset renewal programme on asset fleets with the greatest inherent risk
- Deliver the integrated health and safety strategy which will elevate our critical risk management and assurance processes
- Continue to focus on Visible Felt Leadership
- Continue to implement the asbestos management and removal programme
- Improve the reporting of hazards and near miss incidents and apply these to our critical risk framework
- Enhance our approach to safety-in-design, working closely with field service providers to encourage innovation in reducing manual handling
- Complete our current prioritised programme of replacement of assets that present a risk to the public or to our service providers
- Promote public awareness of safety around our network

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 – and this 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 a higher number 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 any areas of concern and, where action was required, to develop practical solutions that deliver meaningful improvements.

In 2023, we engaged with customers in reliability hotspot areas to provide information about ongoing work and improvements they can expect. Continuous monitoring will ensure that targeted enhancements meet our performance goals. We anticipate a more balanced performance across the network over time, keeping in mind factors like location, terrain, and consumer preferences.

Our efforts to address reliability hotspots are outlined in more detail in Section 7.5. This section provides a comprehensive view of our strategies and actions to ensure the utmost reliability for our valued customers.

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 that we consider the impact of our asset management decisions on affordability across all customers.

KEY STRATEGIES & INITIATIVES

Our AMP planned expenditure seeks to maintain a balance between the desire to minimise price increases today against 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 that we meet the required performance levels, but to prevent the need for significant re-investment 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 towards our cost estimation capability. Our Cost Estimation Practices Plan will support greater accuracy and efficiency in terms of project costs, and it should help us to deliver improved value to consumers

6.2.4. Responsiveness

The responsiveness objective area 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 maturity suitable for incorporating into 'business-as-usual'
- Developing our asset management competency, including collaboration with our industry peers, to allow staff to develop new skills, and provide new challenges
- Increasing the use of scenario analysis to inform our long-term planning
- Developing a comprehensive roadmap for ICT solutions to support network operations
- Managing and effectively analysing increasing volumes of network and asset data
- 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 previous AMP. Thus, we are still in the process of establishing standard requirements and measures of performance throughout the business. In 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:

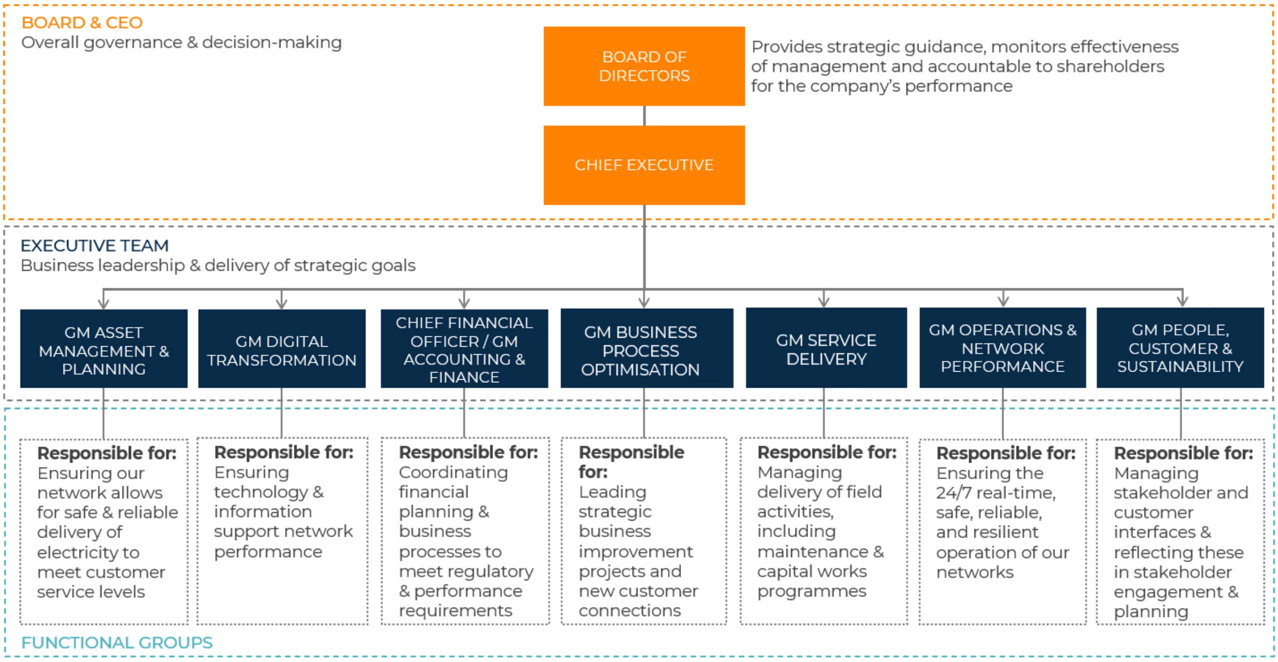
- Managing the environmental aspects of our assets by considering use of available space, resource consents required, constructability, resource availability, and equipment materials and manufacture
- Assessing environmental risks with investment options and maintenance approaches
- Limiting negative impacts from insulating mediums (e.g. oil, SF_6)
- Extending investment analysis to include noise pollution and visual impact
- Over time, aim to reduce 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.

Figure 6-5: Asset management responsibilities



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
- 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
- Responsibility for overseeing risk management practices. The Board also receives and reviews reports by external auditors

OUR EXECUTIVE TEAM

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

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.

Table 6-2: Asset management roles & responsibilities

Functional group	Team	Key asset management responsibilities
Asset Management and Planning	Network Planning	Load forecasting Network HV power flow model maintenance Fault studies and Low Voltage (LV) network modelling Major project and reinforcement planning and scoping 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
	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
	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
	Strategy & Reliability	Coordinating AMP preparation and AMMAT reviews Optimisation of planning and lifecycle network expenditure forecasts Development of long-term network expenditure forecasts Asset management strategy Lead the development of specifications for risk management and quantification Lead asset management development plan Lead network reliability/performance forecast
Operations and Network Performance	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

Functional group	Team	Key asset management responsibilities
	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)
	Operational and Public Health & Safety	Incident management processes Public Safety Management
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 Services Agreements (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
	Health & Safety	Field auditing of contractor health and safety performance

6.4. EVIDENCE-BASED DECISION-MAKING

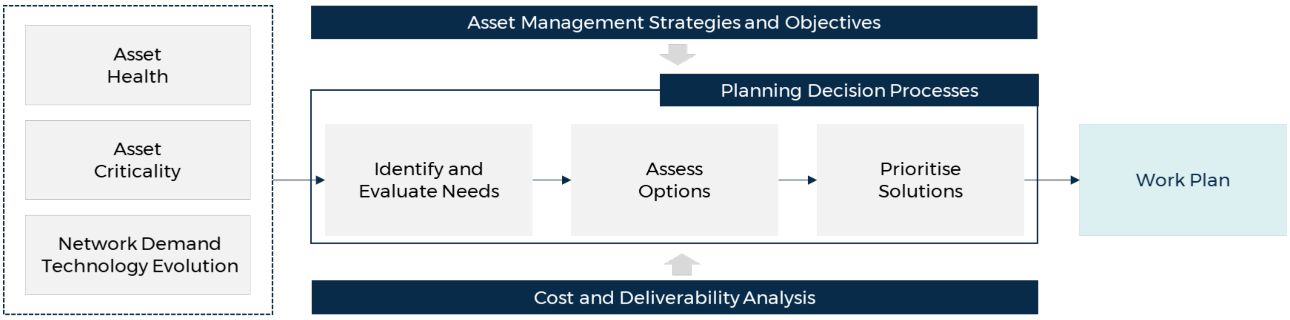
DECISION-MAKING APPROACH

Our approach to asset management decision-making uses processes that test our individual planned expenditure and our overall expenditure.

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 illustrated in Figure 6-6.

Figure 6-6: Decision-making approach



The main steps in the 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.
Work plans	The prioritised solutions will be entered into a draft work plan, which 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 requires 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 new 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 is 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/opportunity. In some cases, a pilot or a trial is required to ascertain whether the innovative practice achieves the benefits indicated by a desktop review. In other cases, the benefits are more certain and implementation risks relatively low, so the innovative practice may progress directly to full implementation following a comprehensive assessment of the opportunity.

We propose to further develop our assessment process for innovative initiatives, but the high-level investment/assessment test is not dissimilar to our traditional investment including an assessment of whether it can:

- Deliver benefits greater than cost, e.g. 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, e.g. 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 rely on third-party collaboration or vendor product/service development. This can make scoping and timely implementation challenging and/or can lead to extensive inhouse 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 have five innovation initiatives underway at various stages of implementation:

- Ara Ake EDB challenge – A collaborative initiative with ANSA to develop tools to determine low voltage network hosting capacity, constraint forecasting and network reinforcement budget forecasting

- **Low voltage network visibility platform** – We have progressed an ROI and RFP for the procurement of a platform and associated analytics to better plan and operate our low voltage network, with ongoing collaboration/innovation on development of new capability/use cases
- **Early fault detection system** – Trial of a technology on the Omakau 33 kV supply line to detect emerging faults and prevent outages – post the trial we will assess the benefits and costs to ascertain whether wider implementation is economic (see Section 11.4)
- **Leaning pole risk assessment** – In collaboration with other EDBs a scale pole model was developed to assist our assessment of leaning pole failure risk, leading to an adjustment in our risk assessment and resulting pole intervention/remediation criteria 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 to risk-based vegetation management programme. 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.

DELEGATED AUTHORITY

Our delegated authority policy (FS-S018) 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.

6.4.1. 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 requirements for meeting our evidence-based decision-making approach. We acknowledge that our ability to optimise 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:

- 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 human error and inconsistencies 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. We are focusing 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 the source data.

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 tools 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 will develop and implement an integration platform for our field service providers to use. This platform will be 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:

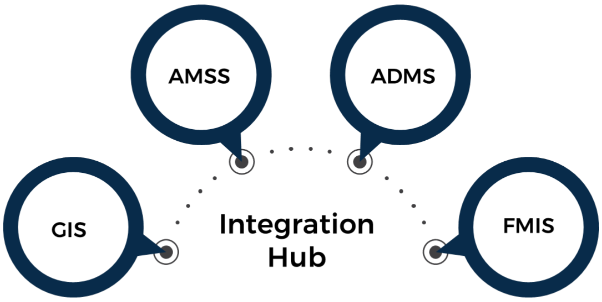
- Geospatial information system (GIS) – which we use for geospatial information
- Advanced Distribution Management (ADMS) and Historian – both of which provide real-time operational characteristics
- Financial Management Information System (FMIS) – which provides financial data in relation to assets (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 will enable seamless capture of asset work order information including asset type, expenditure category and cost information.

This integration will enable us to efficiently and accurately track and report the cost 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 will use 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 transformation. As each system is enhanced, it only needs to be integrated with the integration hub, 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.

Table 6-4 below shows some innovative projects regarding asset data collection and quality, which aim to improve our asset management capability.

Table 6-4: Asset data collection and asset data quality development plan milestones

Key Activities/Milestones	Timeframe	Comments
Asset data requirements		
Definition and documenting of key asset and network-related data requirements	RY23	This will include defining master and dynamic data requirements
Definition and documenting of business rules to support decision-making	RY24	
Asset data collection		
Implementation of automated systems for collecting data from contractors	RY25	From RY23 we will use a mix of mobility tools and integration with FSA partners
Asset data storage		
Implementation of an asset management software solution	RY25	The asset management software solution will be stood up in RY22, with key functionality rolled out progressively over the following three years
Development and implementation of a data integration hub	RY25	The integration hub will be implemented in RY23 and deployed progressively across core information systems over the following two years
Build data management framework		
Implementation of policies, standards and processes to ensure availability and integrity	RY23	Policies, standards and processes are being developed
Improvement of the ways in which we clean up our data	RY23–RY24	Will be progressively implemented across different asset types
Implementation of data management controls	RY25	Will be prioritised based on the levels of accuracy required
Implementation of data audits	RY23	We will implement data audits in RY23, with a view to broadening the scope of these as our processes mature throughout the CPP Period
Introduction of new analytical tools for internal use	RY25	We will progressively implement the business intelligence framework from RY23, prioritising implementation by business need

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 investment decision-making. Table 6-5 provides examples of data limitations and the work we are doing to improve our data and its use.

Table 6-5: Data limitations and improvements

Fleet	Limitation	Improvement
Poles	Data completeness, system capability	Inspection questions needed refreshing to reflect growing understanding of failure modes. These were updated (Overhead Inspection Standard) and rolled out 2023
Crossarms	Data completeness and data quality; system capability	Testing of a sample of condemned crossarms and 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 Application and made appropriate adjustments to our investment plan, reflecting interim uncertainty
Overhead conductor	Data completeness and data quality	New inspection programme and sample testing to validate desk-top evaluation of remaining life
Ground-mounted switchgear and distribution transformers	Data completeness and data quality	Strategic review of inspection needs and frequency, new standards for inspection and asset health assessment to reduce subjectivity and increase repeatability

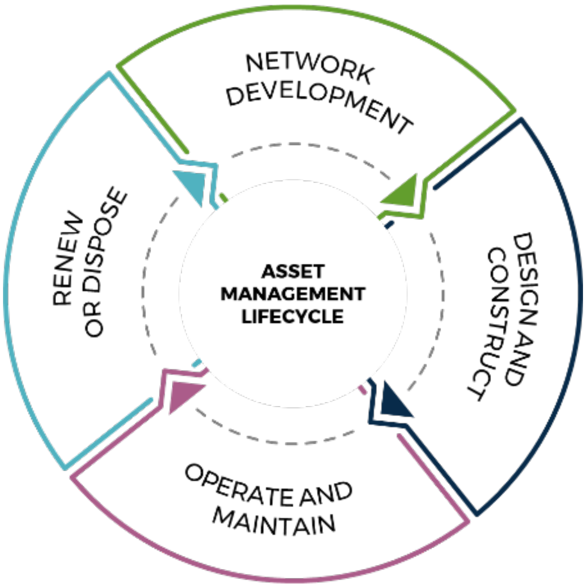
6.5. ASSET LIFECYCLE MANAGEMENT

To make sure we maintain a safe, reliable and resilient network, we manage our assets using a whole-of-lifecycle approach.

We use the term 'lifecycle' to recognise that there are distinct phases in the ownership of an asset, where 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:** 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 key initiatives and projects we will do. 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, the handover of capital projects from our network planning team to delivery teams takes place.

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 undertaken by our design team, contractors, or design consultants. Detailed designs identify construction methods to minimise risks to safety and reliability. They are important for larger projects in order to control cost, quality, and timelines.

Design reviews take place at various stages of projects. The reviews 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, allowing for 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 and forms are managed in our Controlled Document System (CDS) and our drawing management tool, RedEye. Once approved in accordance with Aurora Energy's Controlled Documentation Standard, such documents are made available online to our service providers.

To further enhance Aurora Energy's control over standards, the organisation has newly established the role of Engineering Standards Manager. This step toward establishing a specialised team with responsibility for standards and related documentation and processes will help us achieve long-term consistency across our network.

This 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 the operate and maintain 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 6-6.

Table 6-6: 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 programmed activities that are carried out on a regular basis. Inspection periods for each fleet are carried out 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	Planned work arising from preventive maintenance reporting, ad-hoc identification of a defect 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 & 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 failures 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 down time of common fault and hard-to-source items. We place these in locations that are appropriate to 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, having a wide spectrum of different makes and models in service.	Standardised equipment manufacturer, type, and rating the inventory of spares Contractual arrangement with FSA contractor to manage spares

KEY DRIVERS

The key drivers for maintenance planning are:

- **Asset management system:** We need to gather timely information on assets to make cost-effective decisions
- **Asset condition:** As identified by preventive maintenance activities
- **Legislative or regulatory requirements:** Including minimum frequencies for inspecting overhead line assets
- **Maintenance standards:** Specifying recommended maintenance inspection tasks, servicing intervals and reporting requirements

- **Manufacturers' recommendations:** For inspections tasks and servicing intervals
- **Fault numbers:** Where assets require second response work
- **Asset types:** Assets of different types and manufacturers have unique characteristics. Some types fail more often than others, and some types 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 SAIDI impact
- **Location of faults:** Rural, remote-rural and mountainous areas require additional travel time to address faults
- **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
- **Third-party:** Incidents such as car vs pole and cable strikes caused by third parties lead to outages and potential safety risks

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 PM programme, including creating supporting documentation and systems to introduce more holistic but targeted inspection programmes. 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 6-7.

Table 6-7: 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.
Outsourced Model	For capital work delivery, all network Opex field activities are outsourced. 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 inhouse to ensure core asset knowledge is kept within the business.
Quality Management	Whilst we have quality assurance staff who review many technical aspects of capital work, we do not yet have an equivalent framework for quality management of Opex works. This is an improvement initiative that we have committed to in our CPP Development Plan for 2023 and 2024.

Maintenance stage	Description
Feedback and Monitoring	Two types of feedback are obtained using our FSA. 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: The renewal strategies are informed by the impact of failure, as currently understood. Any fleets that are deemed to have a public safety implication if they are to fail are renewed in a proactive way, prioritised by risk. We also deploy proactive renewal strategies when failure of an asset leads 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 conditions with impact on safety, network performance, asset obsolescence, and regulatory and legislative compliance.

Table 6-8: Renewal considerations

Consideration	What this includes	Key strategies
Safety	Renewals required to limit safety risk. Safety risk management is highest priority for asset lifecycle investment	Safety risk profiles for every fleet (in the form of a risk matrix) used to determine the renewal programme priorities
Network performance	Renewals required to meet reliability targets. Near real-time reliability dashboard and reporting tool indicates performance based on network area	Replacement of legacy installations which 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 its 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) 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	Options selection informed by technical studies, economic assessments, risk analysis, safety reviews, lifecycle cost analysis

DISPOSAL APPROACH

Asset disposal follows the decision to remove it from our network, either because it is being replaced or has become redundant. Disposal activities include planning for disposal, decommissioning the asset and site restoration.

Disposal: Removing an asset from our network, either 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 6-9.

Table 6-9: 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	
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 early stage in project Disposal costs included in overall lifecycle costing
Site restoration & reinstatement	When assets are decommissioned and removed, part or all of a site may be able to be re-used or restored	Consider health and safety and environmental considerations, particularly where hazardous wastes are 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, generally poles, conductor and cables	Direct involvement in relocation design process with third party For poor condition assets, upgrade will be considered at time of relocation Obtain 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

Inherent Risk	Safety	Reliability	Condition	Deliverability
Some assets are generally considered to be inherently riskier than others. With limited resources, fleets with higher risk are prioritised	Meeting the objectives of our Safety Delivery Plan as safety is our primary driver	Focus on reliability for critical assets as a secondary driver or in parallel with safety	For fleets where the overall fleet health is poor and which have a large at-risk proportion in backlog, relative prioritisation is given to prevent the backlog from growing or remaining at an unsustainable level	For some fleets, a large forecast renewal backlog means that even using the additional resources that are realistically available, the risk of the fleet cannot be significantly reduced in the short term. From this perspective, deliverability constraints force us to prioritise across fleets.

Our fleet strategies are an innovative approach which has have 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 as such that renewal identified in the ideal plan, are not achievable due to constraints 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 to a quantifiable risk and investment decision-making tool. Documenting 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 Models in our Fleet Strategies enable us to combine asset specific parameters such as condition, age, expected useful life to inform our forecasts, i.e. which assets are coming to/at their end-of-life over the forecasting period and thus the expected level of investment that is needed.

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

For each fleet, an ideal state renewal plan is created. This is then fed into a process of bringing together 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

Appropriate interventions are defined when the Ideal Renewal Plan, set out in the fleet strategies is unattainable. This can include:

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

If it is suspected or known that like for like replacement may not meet the future needs of the network, a strategic plan around deferral of asset renewals is implemented, risk permitting and with appropriate controls in place. Renewals will be deferred until we have appropriate degree 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 to 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 like financial limitations or resource availability, we refine our renewal plans while capturing residual risks and controls.

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.

Furthermore, we employ forecasting methods, including Asset Health Index Models, to inform our investment decisions. These methods consider asset-specific parameters such as condition, age, and expected useful life. We also rely on historical replacement rate data for a reactive approach to renewals.

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

6.6. ASSET MANAGEMENT CAPABILITY

6.6.1. Asset management maturity assessment tool

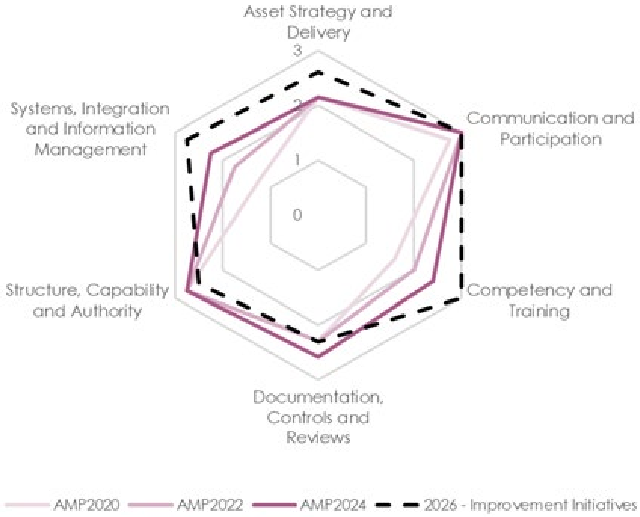
The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment by each EDB of how well they believe that their asset management practices are developed. The tool is based upon a selection of 31 questions extracted from the PAS55 Assessment Methodology. The Publicly Available Specification 55 (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 of the Asset Management Plan.

The AMMAT is arranged in six categories with each question rated between 0 (innocent) and 4 (excellent) allowing a gap analysis to be undertaken when the current state is compared to a future state, such as against the competent score of 3 or a more ambitious target.

Aurora Energy is committed to improving asset management practices and monitors its progress year-on-year. As shown in Figure 6-10 there is steady improvement in the three areas of *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). The dashed black line indicates the level of maturity improvement forecast for the CPP period, given in AMP2020.

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 improvements. By applying a percentage achieved approach we would show a significant improvement in the area of *Asset Management and Delivery*. This is also true in the *Systems Integration and Information Management* space, where initiatives are underway but not fully compliant with the requirements of the next level threshold.

Figure 6-10: Asset management maturity progression



A more detailed breakdown is given in Schedule 13 in the Appendices as part of the evidence summary for each question.

6.7. IMPROVING ASSET MANAGEMENT

6.7.1. Capability development plans

Our AMMAT score is a frank assessment of our current capabilities, processes and practices. Our review indicates a good understanding of the core principles of asset management; as stated above there is room for improvement. Central to our maturity journey we have put development plans in place to advance our asset management capability.

We regularly engage with consumers and other stakeholders to summarise the improvement initiatives that we will be implementing, highlighting the key outcomes for Aurora Energy, stakeholders, and consumers.

ASSET MANAGEMENT DEVELOPMENT PLAN

As part of our asset management journey, we have established an Asset Management Development Plan (AMDP), which outlines key areas of improvement. Our overall AMDP therefore consists of two closely related sets of plans:

- An update of the initiatives included within our 2020 AMDP
- CPP Development Plan initiatives to address the focus areas raised by the Commerce Commission in the CPP reporting disclosure requirements.

CPP DEVELOPMENT PLAN

As part of our CPP information disclosure requirements, we have prepared a publicly available standalone Development Plan, which contains several business improvement initiatives. These initiatives are directed towards key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe that improvements will bring genuine benefit to consumers.

The Development plan is available on the Aurora Energy website.

COMPETENCY AND TRAINING DEVELOPMENT PLAN

We recognise the importance of making sure we have competency growth plans in place to align with our development plans and our asset management outlook.

Our Competency and Training Development Plan supports the business to improve our asset management approach to meet our asset management maturity aspirations. Once fully in place, this approach will provide enhanced performance, and confidence that we can deliver upon our plans.

Table 6-10: Competency & training milestones

Plan focus	Description	Expected benefits	Timeframe for completion
Define competencies required	Defined complete set of competencies required to ensure the success of our AMP and associated development initiatives. This is based on Institute of Asset Management (IAM) Competencies Framework and aligned to ISO 55001	Clarity on the competency requirements for our asset management approach	RY23–24
Competency matrix for all staff	Allows us to assess the level of competency against the set of defined competencies, using staff self-assessment process	Transparency on competency gaps and the ability to prioritise training to inform resource planning and recruitment	RY23–24
Resource Planning Tool	Tool for planning and programming work, and providing visibility to managers who can adjust priorities on a basis of need	Enables us to better understand where our business can best use external resources to support our asset management approach	RY24–25
Training & recruitment plans	Informed plan for closing any identified competency and capacity gaps or constraints	Clearly defined training needs that are informed by business needs. The ability to tailor recruitment to meet our business needs	RY25–26

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.

Further to the competency and training improvements shown above, we have developed a set of focused initiatives to achieve the required improvements in capability.

Table 6-11: Aurora Energy's key improvement tasks

Improvement area	Initiative	Description	Progress
Asset strategy and delivery	Define and evaluate risk	Set the parameters for calculating risk with available data	Selected Fleets have asset risk profiles calculated
Documentation, controls and review	Document Fleet Strategies	Gather data for each fleet. Produce information required to make informed decisions	Fleet strategies written and actively updated
Systems, integration and information management	Improve Data collection, storage, quality and audit	Mobile solutions by RY25, Asset Management information system (Maximo) by RY25, audits in place by end of RY23	Mobile solutions being rolled out, first phases of AMIS completed
Communication and participation	Review Asset Management Policy	Document revied	Awaiting sign off
Structure, capability and authority	Failure analysis, new technology and practices	Investigating VONIC, DER solutions including EV's	Calibrating VONIC against Deuar
Competency and training	Further develop Quality Assurance Practices	Ensure training and competencies are monitored	Standards developed and training performed

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

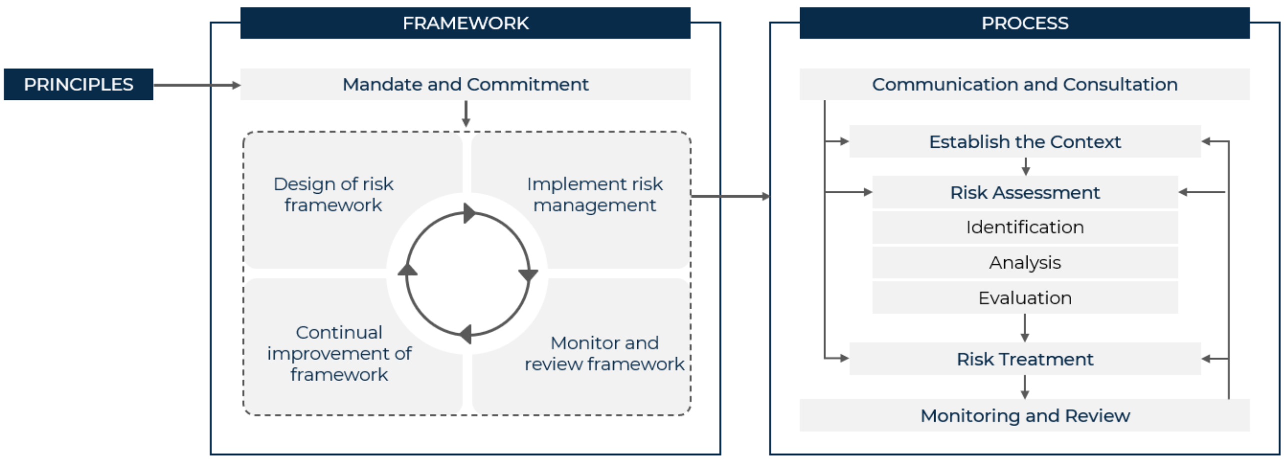
At Aurora Energy, we have an organisational risk control and management framework that enables us to manage the risks and opportunities relevant to achieving our business objectives. This ensures we take a consistent approach to the management of all enterprise risks including the health, safety and 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 an appropriate and timely way in risk management
- **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



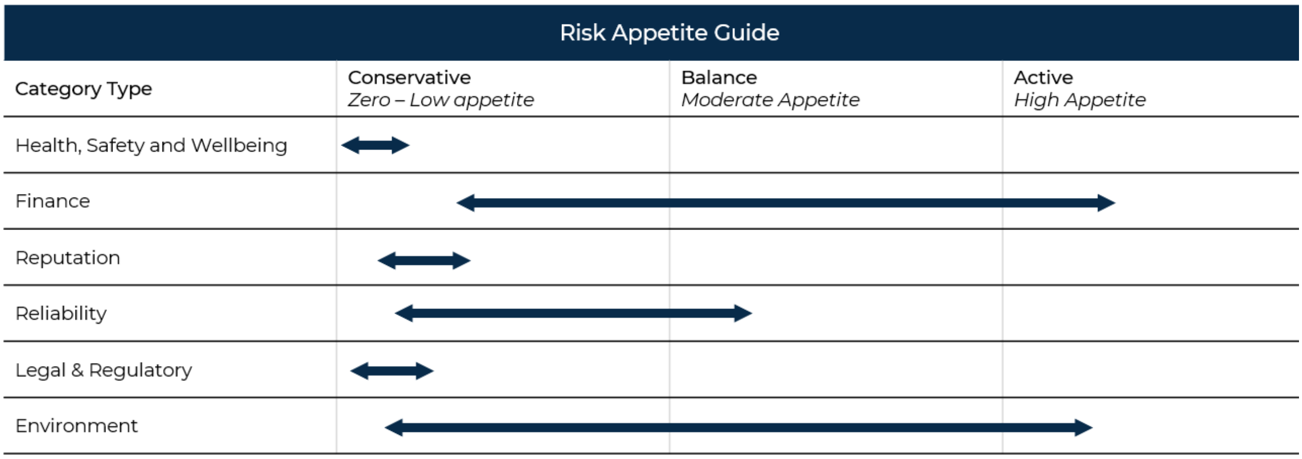
7.1.1. Risk context

We have identified 16 risk themes that align to our strategic business objectives and within which we group our critical risks. These 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 an opportunity for value creation.

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

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 champion 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 that viable risk treatment plans are maintained, for 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. They are also accountable for monitoring and reviewing controls and providing regular reporting to risk owners

7.1.3. Risk assessment and treatment

Our process to assess 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 have been maturing our risk management framework over the past two years and are now turning our focus to improving our control assurance practices. 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 is supporting 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 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 that the risk control and management framework is embedded within the business and provides regular reporting on the status of risks, controls, risk treatments, plans and emerging risks to both the internal Enterprise Risk Leadership Group (comprising the Executive Leadership Team and members of the senior management team) and to the Board, including its Audit and Risk 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 risks 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; or
- 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 both 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 and a shared approach to managing key and emerging risk outcomes), which 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. Managing the risks associated with owning and operating an electricity network is integral for our asset-related risk management. Examples of this are inadequate understanding of failure modes and associated safety consequences, condition monitoring, and correct maintenance practices. With a largely legacy asset base built to different design standards, safety in design deficiencies are a real and present risk that must be identified and managed.

Over and above the business-as-usual risk management, consideration and planning is applied to the potential of high impact low probability events. These include but are not limited to earthquake, 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 have recognised that not delivering our operational works plan optimally is a critical risk area for our business. In particular, we need to understand our role and responsibilities as an asset management company and those of our partners who are supporting the delivery of 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 time are also important and we are managing the risks associated with not being able to do this.

7.2.4. Technology, information and cyber risk management

One of our biggest risks 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 on time. 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 and/or 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 preventative 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

Maintaining our licence to operate is a key strategic objective for Aurora Energy – 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. We are actively managing through a number of programmes and controls 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 put 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 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. We have taken the decision to target safety risk as our highest priority to address.

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 any hazards presented by our assets. We also differentiate between assets that are not accessible to the public and those that are.

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

Once we have defined the safety risk for our assets, 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 risk as 'harm to either a member of public or to personnel by an asset'. We recognise 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, as opposed to areas of criticality as given in our GIS.

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

- Support Structures
- OH Conductors
- OH Switchgear
- OH Transformers
- UG Cables (exposed parts and terminations)
- GM Switchgear
- GM 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), linking 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 in enhancing public and operational safety. Expanding our focus, we are developing a broader approach that encompasses reliability risks, 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.

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

The success of our risk-based approach is evaluated by verification of asset risk levels we forecast in our CPP Safety Delivery Plan. We are evaluating our annual progress against the plan. Additionally, 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. Industry guidelines recognise that asset health is not purely age based but also addresses components of historical usage, cost of ownership, and compliance. Traditionally age has been the proxy for health, so has been the main driver behind our asset replacement and renewal forecasts. Data from inspections is now feeding condition (see below) into our models, improving the accuracy of prediction.

Our approach combines condition and age data to modify the base maximum practical life 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 the basis for the categories 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 that 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 set to follow 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.

7.3.4. Asset condition

Asset condition either reflects normal deterioration due to the asset ageing processes or points to an excessive impact of 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 four years we have made good progress with our plan to include inspection programmes for all our fleet assets.

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 upon its location and probability of exposure. We have developed criticality frameworks across several fleets from data held in our GIS database, which enables us to prioritise expenditure on assets by safety consequence of failure, thus helping us to achieve our safety risk goals outlined in our CPP Safety Delivery Plan. As part of our maturity journey, we are developing a more comprehensive approach, which 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 asset health criteria are then applied to rank the assets in order of health, with the scores then allocated to 'bins'.

This results in an Asset Health Index for each fleet, which can be ranked in order of worst to best. Criticality from the asset location is then applied, resulting in the asset criticality index. The 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	Insignificant	Minor	Moderate	Major	Catastrophic
Almost certain	Medium	Medium	High	Extreme	Extreme
Likely	Low	Medium	Medium	High	Extreme
Possible	Insignificant	Low	Medium	High	High
Unlikely	Insignificant	Insignificant	Low	Medium	High
Rare	Insignificant	Insignificant	Low	Medium	Medium

The impact levels are defined in our Risk Control and Management Standard 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 falling within the intolerable area 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 a risk level across the risk appetite boundary (yellow line) are justified by a requirement to take 'all reasonable practical steps' to reduce risk, while projects that reduce risk outside of the 'Intolerable Risks' 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.

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 preventative measures, and ensure that we are ready to respond.

Our current approach is based on the *4Rs* 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 in gap analysis under the *4Rs* approach. The RMMAT consists of 71 specific questions aggregated into 19 functions covering the *4Rs*, 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. We have developed an RMMAT action tracker with actions allocated to appropriate personnel. At this stage, our internal set of initiatives focus mainly on business continuity and network operations.

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 (BCPs)	Recovery plans	Document review & training	Incident management	BCP in action	Return to business as usual	Incident review and continuous improvement

Thus, our approach (as depicted above) has the following five elements:

Reduction: Identify Aurora Energy's critical business functions and analyse the risks to these 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 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/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 associated critical resources required to deliver those functions, even if at a reduced level. These plans include back-up options for supply, such as generators and a mobile zone substation, 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 and ensure that we are taking learnings from other responses around the country, such as Cyclone Gabrielle, to ensure that our we adapt and remain ready to respond.

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 high impact low probability (HILP) events and the impact of climate change. This understanding is integral to our asset management and strategic planning, guiding a comprehensive approach to enhance network resilience.

COMPREHENSIVE PREPAREDNESS FOR HILP EVENTS

Understanding the severity and frequency of High Impact Low Probability (HILP) events is essential for our resilience planning. We have been involved in the Otago Lifelines project to identify risks relating to potential hazards to lifeline infrastructure across Otago, identify mitigation strategies and identify opportunities to improve critical infrastructure resilience. To aid our resiliency planning, we also sought additional expert advice on the impact of HILP events on our subtransmission assets.

This work identified that storm/flooding, sea-level rise, earthquakes (including secondary impacts such as landslips, tsunami and liquefaction) and high winds are our major natural disaster risks. We also keep up-to-date with FENZ's work in relation to fire risk across Otago.

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 recognising climate change as a key driver for increased natural hazard risks.

- **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 these risks, 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:

- **Asset Upgrades and Relocations:** We have some initiatives in place and will continue developing 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 analyses 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 adopts a measured approach, balancing the tangible steps already taken and 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. ENSURING RELIABILITY

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. As such, we must ensure that our network assets are maintained in good health, and that we take appropriate actions to reduce the impact of external factors such as vegetation, severe weather, wildlife, and third-party damage that can affect supply. As we make improvements to our network, we also try to reduce the impact on consumers for any 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; and
- Reducing the impact on consumers when a fault occurs.

For the former, 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 are actively reviewing 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 (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 a set distance from our lines. Increasingly, we are experiencing issues with trees and branches outside the regulated distances falling through our lines, particularly during severe weather events. Removing these trees would require significant expenditure, along with support from landowners to provide consent for removal. We are investigating a risk-based approach to managing vegetation outside the regulated distances which would provide the greatest balance between additional cost and potential reliability improvement. (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 is a persistent issue. We can then proceed with more advanced inspections to help us identify and address the issue.

In addition to reducing the number of unplanned outages across our network, we also aim to deliver benefits from 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 are in effect from 1 April 2024. Ongoing performance will be 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 that this investment will 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:** We consider the potential loss of supply to consumers, plus any potential alternative supply options, when assessing the realistic impact of failure for all zone substation assets (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. Critical circuits are prioritised on a 12-month inspection cycle vs a standard three-year cycle for standard circuits (see Section 11.2.4).
- **Asset inspection trials:** In cases where we trial 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 – with the aid of machine learning and AI tools – better understanding the factors that drive our reliability performance and what actions we can take to address them. We are also developing network models to help 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 to 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 into specific projects, but have allowed for some flexibility to address reliability issues as they emerge.

Table 7-5: Reliability investment over planning period (RY24 constant, $m)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Reliability investment	0.3	0.3	0.6	0.6	0.6	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 solution to restore performance to normal levels.

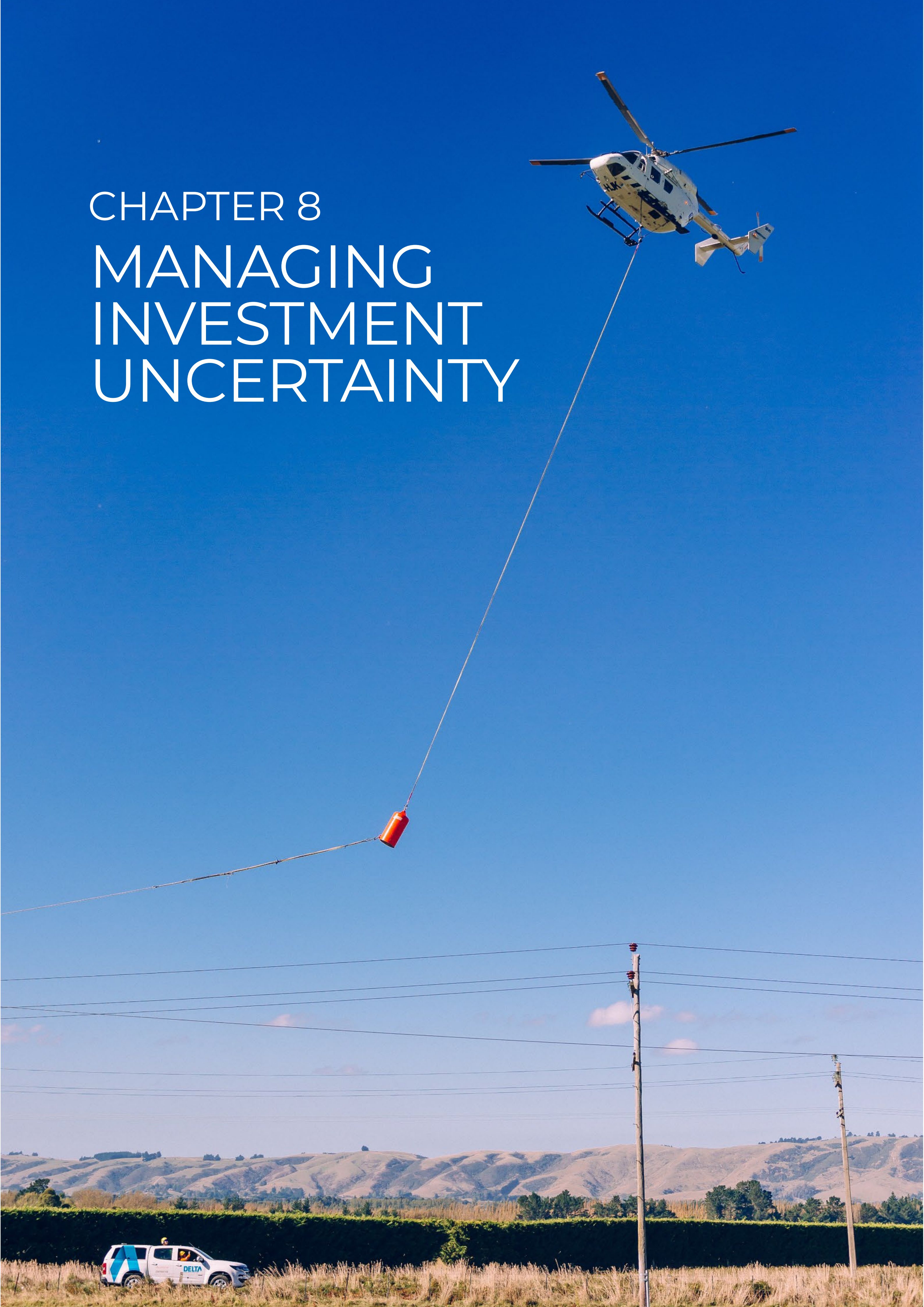
Table 7-6: Reliability improvement goals

Improvement Goal	Plans to Improve Performance
Establish performance targets	• Refine performance targets at a circuit level, with an aim to set 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 for 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.

Improvement Goal	Plans to Improve Performance
Monitor fault performance	• We currently track outages at a circuit level so that we can identify how individual circuits perform against target. • As part of our ADMS (Advanced Distribution Management System), we record the 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 to 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 preventative solutions. Over time we plan to expand this approach to all network faults. • More detailed data capture for all faults helps us to make informed decisions when we need to address performance issues in a specific area. Where we can identify common factors, it helps us to drill into 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 in 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 technology 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 on future expenditure.

This year's AMP, much like its predecessor, finds us navigating a complex landscape characterised by various input drivers, each presenting a unique level of forecast uncertainty. Managing the extent of climate change is a global effort and is driving the emergence of and investment in new technologies to eliminate or capture the creation of carbon, and also reduce the impact of climate change consequences on our network. In addition, the emergence of new digital technology 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 developed via the use of scenarios. Our AMP forecasts present a minimum viable plan as one scenario, which we will review and flex as new information becomes available.

8.1. EXPLORATION OF INVESTMENT UNCERTAINTY

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

- **Asset Renewals:** While the necessity for asset renewals is well understood, determining precise expenditure remains a flexible endeavour. Our goal is to strike a balance between spending that caters to growth demands and those that ensure safety, while avoiding prolonged periods of vulnerability. With less expenditure on renewals compared to AMP23 as our view of asset health matures (refer to Chapter 15), we are optimising spending to support increased investment in System Growth.
- **System Growth:** Forecast growth shows a need for greater investment in capacity. However, the unpredictability of global economic factors adds an additional layer of uncertainty. Moreover, the growth trajectory of Central Otago – potentially accelerated by enhanced air travel – introduces another element of unpredictability.
- **Decarbonisation and DER:** Our network does not anticipate major electrification projects exceeding 10 MW. Nevertheless, the timing and level of expenditure on flexibility services and the conversion of traditional carbon-based fuel sources introduces uncertainty. The transition to electric vehicles coupled with solar power adoption rates will influence spending on our low-voltage networks.
- **Reliability:** We remain committed to enhancing the health of our assets, particularly with safety benefits in mind. However, the precise level of expenditure to address reliability hotspots is dependent on yet-to-be-established consumer reliability preferences. This area also explores the potential solutions based on enhanced network configurations, remote switching, and automation to align with consumer reliability expectations.
- **Resilience:** We have identified short-term actions to strengthen network resilience. However, the exact magnitude of expenditure for resilience event response and recovery is unknown. This uncertainty extends to the potential impact on network configuration and equipment standards. To address this, our Capex forecast (refer to Chapter 15) reflects a proposed $20 million expenditure over the AMP period.
- **Digital Transformation:** While certain aspects such as core asset management and Advanced Distribution Management Systems (ADMS) development are assured, expenditure on low-voltage (LV) visibility and integrated risk quantification remains unclear. The dilemma of choosing between smart meter data, network sensors, or third-party data sources continues to pose a challenge. Furthermore, the need for a network twin, which holds the potential to significantly enhance resilience modelling, remains unexplored.
- **Vegetation:** Management of vegetation remains critical to preventing unplanned outages. The outcome of a 2023 review of

the Tree Regulations is not yet known, but a key aspect of this review was the treatment of fall zone trees which have a history of causing outages during storms. Additional regulatory obligations related to fall zone trees would increase our vegetation management costs.

- **Consumer Poles:** Most (73%) of the increase in our corrective maintenance forecast is associated with completing the consumer pole testing and remediation programme. The need case for this programme was tested as part of the CPP Determination, but due to prioritisation of the limited operational expenditure allowance during the CPP period some of this work will be deferred into the DPP4 period.

8.1.1. System growth forecasts

One of the greatest areas of uncertainty is the pace and impact of electrification 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 this investment uncertainty, the Commerce Commission has created a regulatory mechanism called 'capacity event reopeners.' This mechanism enables us to seek additional regulatory allowances at a later date when the uncertainty is removed from the need to invest.

Our approach when developing our system growth forecasts is to create a minimum viable plan to meet known growth-related deficiencies and gaps. We will rely on the DPP4 reopener mechanisms to respond quickly if required to seek approval for system growth projects where the need is confirmed or arises in the DPP4 period. For this approach to be effective/workable it will be necessary for the Commerce Commission to develop an efficient approvals process.

Our DPP4 period forecasts exclude major projects where there continues to be uncertainty associated with the need case or the timing of the upgrade project. Table 8-1 provides a list of projects that may be required over the DPP4 period, but which we have excluded from our expenditure plan in this AMP due to uncertainty.

Table 8-1: Capacity event reopeners (excluded major projects)

Excluded major projects	2024 AMP RY26–30 ($K)
Jacks Point Substation	4,438
New Bendigo Customer (N-1 supply)	22,575
Riverbank Second Transformer	2,995
Riverbank distribution feeder Stage 2	1,070
Parkburn Distribution Network	490
Parkburn Substation	7,362
Dunedin Airport substation	2,647
Total	**41,577**

Additional capacity event projects may also emerge as new information becomes available, but the table above represents our latest view on what may be triggered during the DPP4 period. There is a range of reasons for the uncertainty associated with these projects, including growth forecast uncertainty, electrification timing, customer project decisions, and competition with a neighbouring EDB.

8.2. 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 with their adoption of future technologies, such as electric transportation and DERs. These technologies are adopted and valued to different extents by consumers across our network, and this variability represents an ongoing challenge.

Another priority investment driver is asset safety. While we have a solid framework for evaluating asset safety, predicting the future development of populated areas and their safety needs is uncertain. Accurate forecasting is challenging due to the speculative nature of these predictions.

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 fully capturing the potential shifts in consumer behaviour and preferences.

C

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. Climate and 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. These priority investment drivers inform our network development expenditure.

We use a risk-based network development approach to inform the need to invest. Safety, reliability, environment, customer satisfaction and other risk categories are assessed, and higher relative criticality is established in order to prioritise the 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 power quality regulatory and industry standards.

9.1.1. Growth & security investment

Growth and security planned expenditure are 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 capacity shortfall 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 associated with 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.[3] 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.[4] With the uptake of 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.

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 1,200 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. This 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.

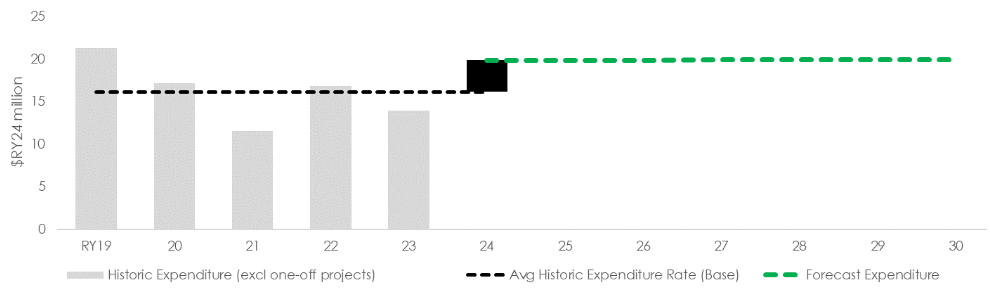
Historically, we have seen significant year-on-year variation in both consumer connection Capex and capital contributions. In developing our forecast, we considered the following inputs and made the following assumptions:

- 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

[3] 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**.

[4] 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

We published a refreshed Capital Contributions Policy on 1 July 2021, which results in an average consumer contribution of 60% for new and upgraded connections. To ensure the Capital Contributions Policy continues to target a 60% consumer contribution we will be publishing an updated Capital Contributions Policy in April 2024 to adjust for inflationary increases since July 2021. No substantive changes are expected to the Capital Contributions Policy during the DPP4 regulatory period.

9.1.3. Reliability

Reliability-driven expenditure aims to improve reliability of service, maintain, or improve the safety of the network for consumers, employees and the public, meet legislative requirements, or reduce the impact of the network on the environment. The reliability performance of a feeder is significantly influenced by network configuration. Reliability-driven expenditure goes through the same network development process as other expenditure.

During the CPP period, we have targeted our spending on areas where repeated outages occur and impact large consumers. Our plan is to step up spending from RY27 onwards, focusing on improving the reliability of our worst performing feeders and our extended and heavily loaded distribution feeders, and increasing operational capability.

Table 9-1: Reliability drivers

Reliability drivers	Description	Investment impact
Minimise impact of outages	By reducing the severity (extent and duration) of outages. This is particularly effective on heavily loaded or older circuits where the impact on consumers may otherwise be unacceptable.	Increase
Address poor performance	Spending targets feeders with relatively poor performance in terms of reliability (worst-performing feeders).	Increase
Network safety	Network safety risk is covered by our renewal workplan, and there is no dedicated safety-specific expenditure (e.g. retrofitting of arc-flash protection) during the CPP Period. It should be noted that our general renewals spending targets all the drivers within the RSE category.	Increase
Increase network control	Remote controlled switches reduce time and increase efficiency instead of sending contractors to locate and operate a manual switch. Increase the level of central oversight and control we have on our network. This increases our operational flexibility and improves the real-time control of our assets.	Increase
Automation	Automation devices are a cost-effective way to address reliability performance and allow prudent deferral of more expensive investments.	Increase

9.1.4. 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 regulatory 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 that network capacity is adequate. Undersized reticulation or high impedance transformers (where required to manage fault levels) will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives) that can create high levels of harmonic distortion, and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

At this stage, work to address power quality issues is reactive, whereby we respond to consumer complaints. We are using Distribution Transformer Monitoring (DTM) devices to provide 'near' real-time data and alarms to engineers' desktops. We are installing DTMs at strategic locations to provide us baseline power quality information of the network and are aiming to have a total of 72 units installed by end of RY24. We also install power quality meters to verify consumer complaints whether it's a network issue or a customer-side issue.

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

VOLTAGE MAGNITUDE

Regulations require voltage to be maintained between ±6% at the point of supply except for momentary fluctuations.

HARMONICS: DISTORTION AND INTERFERENCE

Harmonic voltages and currents in an electric power system are typically a result of non-linear electric loads. Non-linear loads include variable speed drives, switch mode power supplies, and 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. This 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.

The limits indicated in Table 9-2 are used 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 9-2: 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 additional 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 and/or frequent outages or compromise power quality (voltage drop).
- **Compliance:** We aim to maintain compliance with all relevant legislative, regulatory and industry standards. Priority is given to projects that address any 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, the knowledge, experience, and professional judgement of our asset management team is relied upon 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 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 measure focuses on the following three 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 in 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. Low values indicate the provision of excess capacity and cost, while higher values can also cause concern due to not having sufficient capacity available.

Table 9-3: Load factor

Load Factor	Historical (%)			Forecast (%)									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Dunedin	49	48	50	50	50	50	50	50	50	50	50	50	50
Central Otago & Wānaka	58	55	58	57	57	57	57	57	57	57	57	57	57
Queenstown	45	44	49	47	47	47	47	47	47	47	47	47	47
System	**53**	**51**	**53**	**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 ICP) over electricity entering the system.

Table 9-4: Loss ratio

Load Factor	Historical (%)			Forecast (%)									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Dunedin	5.5	4.8	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Central Otago & Wānaka	7.4	7.1	6.8	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Queenstown	4.8	5.6	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
System	**5.8**	**5.4**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**

9.3.3. Total transformer capacity utilisation

Total Transformer Capacity Utilisation is the maximum coincident demand divided by total distribution transformer capacity.

Table 9-5: Transformer Utilisation

Load Factor	Historical (%)			Forecast (%)									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Dunedin	37	37	32	37	37	37	38	38	38	38	38	38	38
Central Otago & Wānaka	20	21	26	25	25	26	26	26	26	27	27	27	27
Queenstown	36	36	39	38	38	38	38	39	39	39	39	39	39
System	**30**	**31**	**30**	**30**	**30**	**31**	**31**	**31**	**32**	**32**	**32**	**32**	**32**

9.4. IMPACTS OF CLIMATE CHANGE

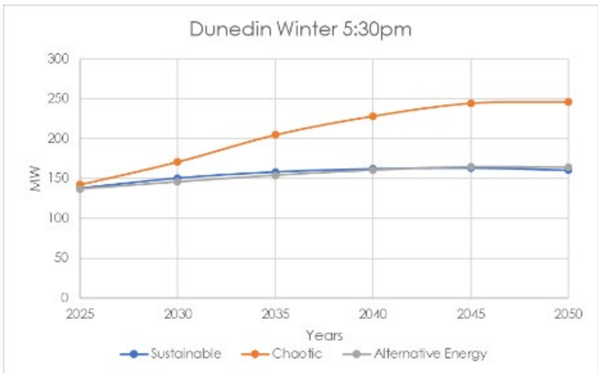
9.4.1. Decarbonisation scenarios

We have developed three decarbonisation scenarios: *Sustainable*, *Chaotic*, and *Alternative Energy*. While the scenarios are qualitative descriptions of the range of futures, they allowed 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 for a range of futures and highlights the importance of developing a strategy and action plans to manage this expenditure.

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

The Chaotic scenario shows higher demand. The Sustainable and Alternative scenarios have almost the same peak demand; the main difference is that the Sustainable scenario optimises the use of the network while the Alternative scenario regresses in the use of the network.

Figure 9-2: Forecast peak demand per scenario



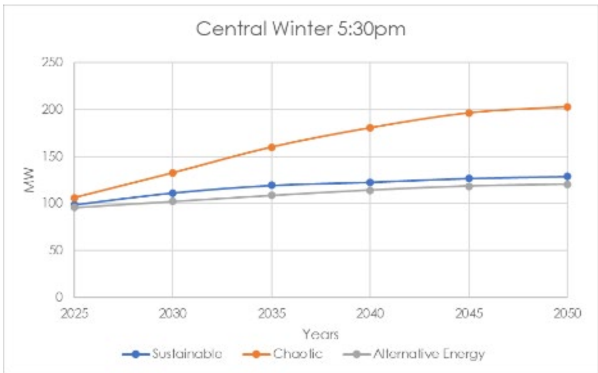
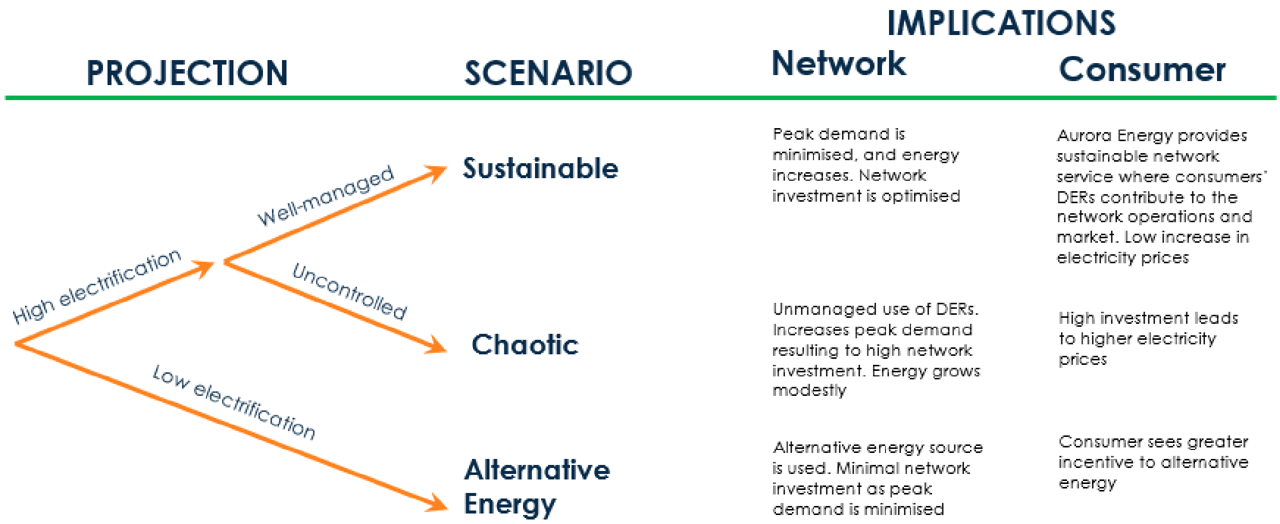


Figure 9-3 shows the implications of each scenario from the perspectives of the network and consumer. These viewpoints indicate that the Sustainable scenario would be the best outcome, so we are planning our investment based on the Sustainable scenario. Under this scenario, we will optimise expenditure on network capacity and consumers will benefit from a low increase in electricity prices.

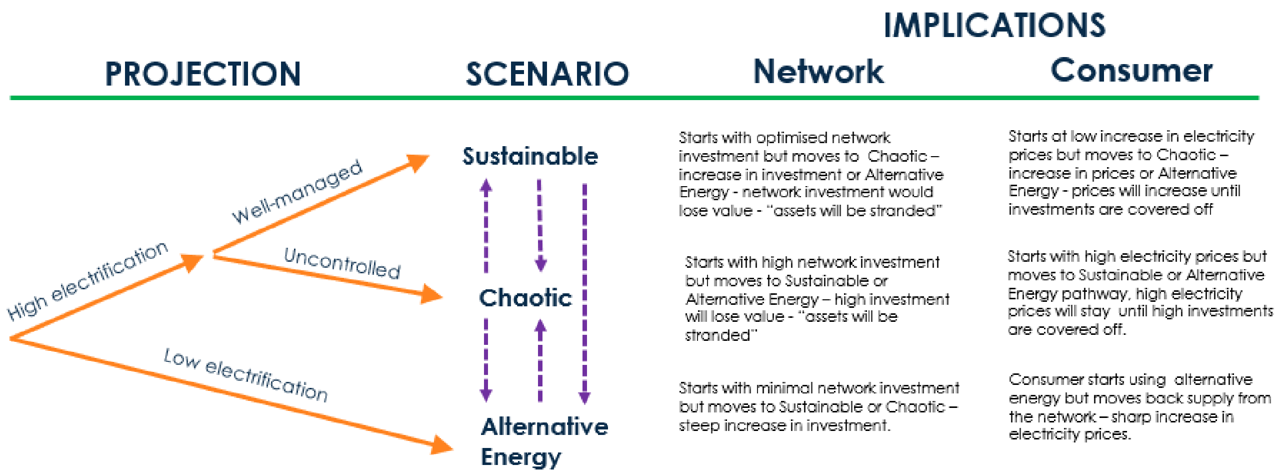
Figure 9-3: Decarbonisation scenarios and implications



The Sustainable scenario requires careful management of peak demand as energy use increases overtime. 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 9-4 illustrates this view.

Figure 9-4: Moving from one scenario to the other



9.4.2. Impacts of climate risk

Our network is planned and built based on Aurora Energy's security of supply. We consider supply resiliency in areas of the network that requires 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 the 10-year expenditure plan. We acknowledge the changing and increasing number of severe weather conditions are having a great impact on the network and the consumers. Lessons learned from Cyclone Gabrielle have certainly reverberated throughout the industry, and we will prepare a resiliency strategy and plan.

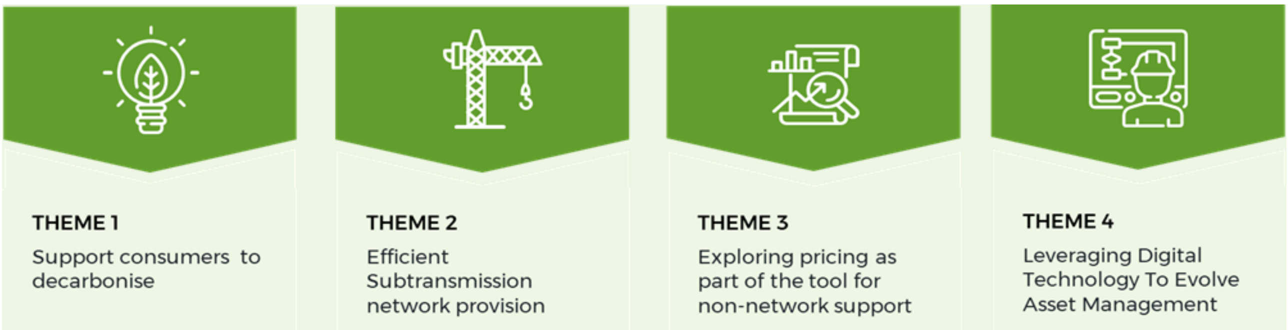
9.5. NETWORK EVOLUTION

Our network evolution plan prepares Aurora Energy for a future in which electricity plays a key role in decarbonisation. We will support consumers' adoption of EVs, PVs, battery storage, PV-battery or other forms of future DERs installed on our network. We consider DERs as an important toolkit to manage the distribution 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.

9.5.1. Network evolution themes

We have four key network evolution themes, as summarised in Figure 9-5. These themes are further described below.

Figure 9-5: Network Evolution Themes



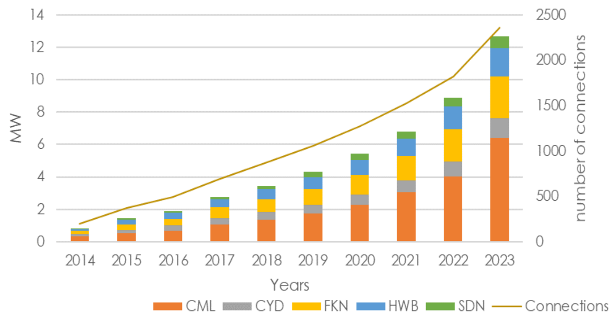
THEME 1: SUPPORT CONSUMERS TO DECARBONISE

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 25.

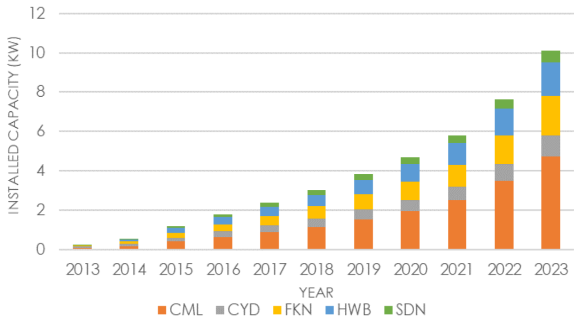
Figure 9-6 shows the 10-year uptake of solar generation in our network. Total solar generation capacity is 12.7 MW, which equates to 4% of the system maximum demand with 2,360 connections. In the last five years, solar generation has grown 1.9 MW annually. Cromwell GXP has the highest solar generation with 6.4 MW and an annual increase to 2023 of 2.43 MW, which includes 990 kW of Devon Dairy.

Figure 9-6: Solar generation 10-year uptake



Small-scale solar DG (<10 kW) capacity (Figure 9-7) grew by 2.5 MW from 2022 to 2023 compared to 1.8 MW from 2021 to 2022. 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: Small-scale (<10 kW) solar generation 10-year uptake

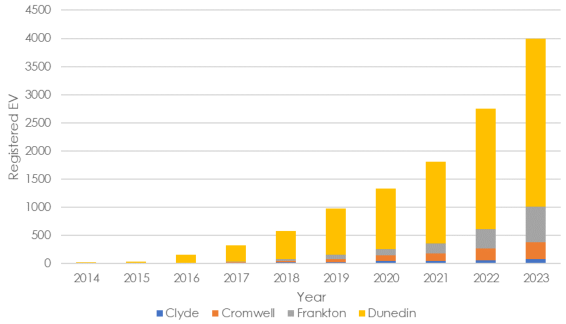


ELECTRIC VEHICLE UPTAKE

Unlike solar generation, which goes through our connection process, residential EV chargers do not. Commercial EV chargers (e.g. ChargeNet) go through our connection process, which gives us visibility. To date, all EDBs do not have visibility on residential EVs and their chargers. Waka Kotahi New Zealand Transport Agency (NZTA) EV registration is the only available source data, but is of limited use. According to NZTA, there are about 3,995 EVs in our network. Figure 9-8 shows the 10-year uptake of registered EVs. Most of these are in Dunedin, where the daily commute is short compared to Central Otago.

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 9-8: Registered electric vehicles 10-year uptake



THEME 2: EFFICIENT SUBTRANSMISSION NETWORK PROVISION

The Upper Clutha DER solution demonstrated the ability to utilise solar-batteries with hot water load to reduce load during constrained periods. Through our procurement process in 2019–20, we engaged solarZero in a non-exclusive agreement to utilise their solar-battery systems. We developed a Flexibility Management plan that manages the operation of Aurora Energy's hot water channels and solarZero's solar-battery during constrained periods on the Upper Clutha subtransmission circuits. Figure 9-9 illustrates the system architecture and Figure 9-10 shows the functional diagram.

Figure 9-9: Flexibility Management – System architecture

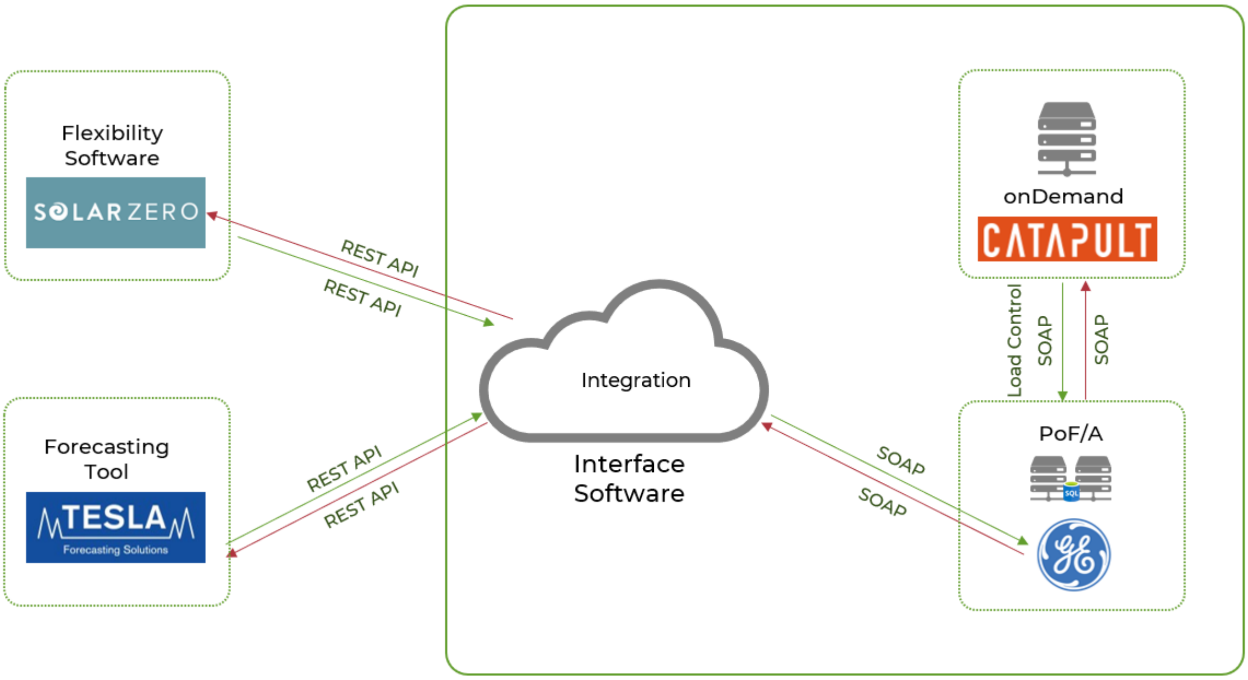
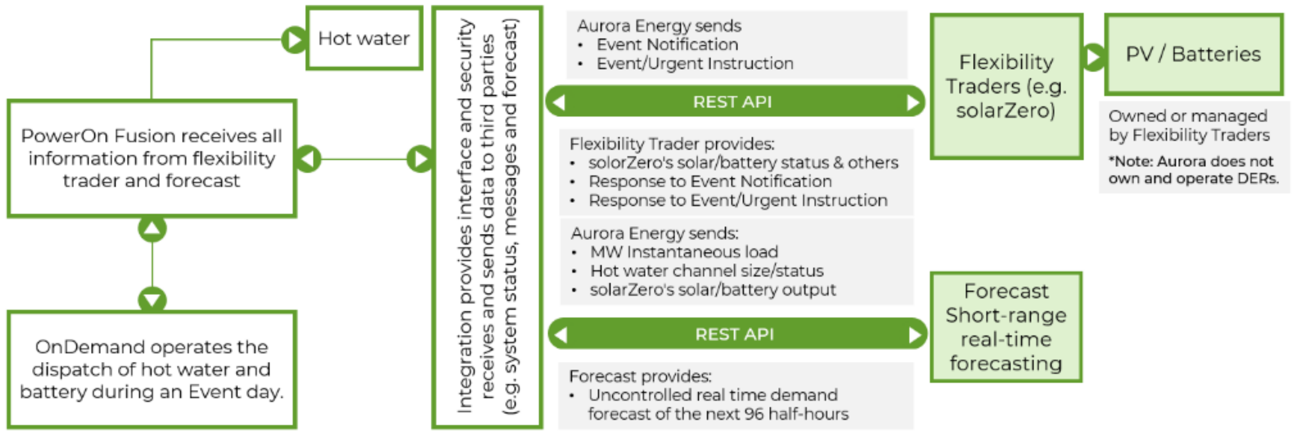


Figure 9-10: Flexibility Management – Functional diagram



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

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

THEME 4: LEVERAGING DIGITAL TECHNOLOGY TO EVOLVE ASSET MANAGEMENT

LV VISIBILITY

Theme 1 shows the penetrations of solar and electric vehicle in our low voltage network. The level of penetration has not led to power quality issues at this stage. However, we anticipate that this will continue to increase leading towards 2050. However, the LV network has been a passive network historically and spending after installation has been reactive in nature.

Our preferred way to achieve LV visibility is through the use of smart meter data and distribution transformer monitoring (DTM) data for data analytics in combination with Aurora Energy systems to understand the LV network. We are in discussion with metering equipment providers for access to operating network data – for example, voltage, current and phase angle.

We are currently working through a procurement process for an LV Visibility platform. The platform aims to provide us with the view of the LV network, perform data analytics and provide monitoring. This enables us to take initiative in low/high voltages occurrences and power quality issues, be proactive in identification of safety hazards (e.g. broken neutral), optimise asset capability, improve network performance, enable operability of the LV network and, foremost, improve our consumer service.

LV DG HOSTING CAPACITY STUDY

Aurora Energy and ANSA Consulting conducted a study of DG hosting capacity during the initial stages of the Upper Clutha DER solution project. After this, a network-wide hosting study was conducted. We will re-run a hosting study for the whole LV network once we have begun receiving smart meter 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:

- Level of penetration and size of PV system and EV chargers that can be connected prior to occurrence of constraint
- Constraints (existing and likely to occur) – such as distribution transformer loading, LV feeder loading, or voltage incursions outside the regulatory limit
- Locations on the LV feeder where constraints can potentially occur

Both LV Visibility and DG hosting capacity will aid asset management of the LV network in terms of:

- **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 occur, 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 that can be incorporated in GIS and used in the DG connection process

9.6. NON-NETWORK SOLUTIONS

When the network becomes constrained, spending on new infrastructure may not be the best option to relieve the constraint. Non-network solutions can enable deferral of much greater capital expenditure that is usually associated with network solutions. This provides value in terms of lower lifecycle cost, 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 9-6.

Table 9-6: 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 assist in managing the 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 is an alteration of consumer behaviour in response to incentives provided by the distribution business (or retailer). The key difference between DSM and DERs is the greater flexibility of the latter. DERs also have 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 the 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 DERs and smart appliances.
Value Stacking	DERs in the community provide value stacked benefits for consumers, electricity distribution businesses, Transpower and NZ. Value stacking provides the most benefit as it maximises the value of DERs to multiple benefactors. This is the model we used for Upper Clutha capacity support.

Figure 9-11 illustrates how value stacking works and how the benefit is translated from one consumer to NZ. In this example, the consumer has a PV-Battery system.

Figure 9-11: Value stacking

Encourages increased uptake and acceptance of the technology, and ultimately supports the nation's decarbonisation goal.	NEW ZEALAND
Wholesale Electricity Market - Generation Benefits by enabling optimisation of base load generation with new intermittent renewable electricity generation.	WHOLESALE ELECTRICITY MARKET
National Grid - Transpower As grid owner, capital investment deferral. As system operator, assists in managing system stability in terms of voltage and frequency.	NATIONAL GRID
EDBs like Aurora Energy Deferral or potential avoidance of major capital investment. Network benefits such as constraint management, reduction of everyday peak. Supports network restoration during major event (e.g., storm), voltage support and increased asset utilisation among others.	ENERGY DISTRIBUTION BUSINESSES
Consumers with DERs Benefits on savings in electricity bills, export excess generation and back-up power supply. Working with Flexibility Traders (suppliers) who aggregate these DERs and provide services to EDBs like Aurora Energy or Transpower, providing additional benefit to the customer.	CONSUMERS

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 security criteria, reliability and power quality under forecast demand conditions. We consider both network and non-network options in our planning processes. We 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 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 high demand times 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 supply interruption).

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

Feeder classifications provide information on network geography or the types of loads supplied by each zone substation, and these influence its security classification.

Distribution feeder security guidelines are established for each feeder type depending on the type of loads. 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, especially in the mass-market, or at lower voltage levels, is impractical. Our current security criteria are therefore 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 the section. When planning for load growth, we aim to optimise the level of security and fault tolerance 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 is 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 2 hours	No interruption for 50% and restore remainder within 2 hours
Rural/Semi-Rural	GXPs supplying predominantly rural and semi-rural areas	15–60	No Interruption	Restore within 4 hours	No interruption for 50% and restore remainder within 4 hours
Substation					
Category Z1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	15–24	No Interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Category Z2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0–15	Restore within 2 hours (may include use of mobile substation)	Restore 75% within 2 hours and remainder in repair time	Restore in repair time
Category Z3	Predominantly rural and semi-rural areas	0–15	Restore within 4 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 2 hours and remainder in repair time*	Restore in repair time	Restore all but 1 MW within 2 hours and remainder in 4 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 4 hours and remainder in repair time*	Restore in repair time*	Restore all but 1 MW within 4 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.

Medium-term (3–5 years) projects are captured in the business case paper and long-term (6–10 years) projects in a high-level paper.

Figure 10-1: Network development process

Identify Needs	Options Analysis	Economic Analysis	Preferred Solution	Project Definition
Needs identified through: • Demand forecasting in relation to security of supply, regulatory limits, reliability and operation of the network • Geographical model • Large customer connections, operational requirements, legislative and regulatory compliance, and safety requirements can trigger a need case.	Complexity depends on: • Level of risk associated with the project • Likely cost of the project Analysis considers: • Other related works (e.g., renewals) which may create cost-effective and efficient delivery • Network and non-network options (e.g., flexibility services) • Long-list options are filtered to short list by defined criteria.	Applied to shortlist of options. Economic analysis encompasses the whole-of-life costs of each option. Three main aspects are considered for each option: • Capital expenditure, • Probabilistic reliability cost • Operational expenditure.	The preferred solution is identified by cost and benefit analysis.	Project definition document prepared for short-term needs (e.g., 1–2 years). Describes the scope of the project, including references to the development process (i.e., need case to preferred solution stage).

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 demands. 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 such example. 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. We have incorporated these in our demand forecasting tool to give us a view of peak demand in the 10-year AMP plan.

We have included decarbonisation levers in our demand forecast as one of the actions from the decarbonisation study. We forecast demand on an annual basis, looking 10 years into the future at the GXP, subtransmission and zone substation levels. We also consider future load on HV feeders, if needed, by adjusting for any known step changes, for example, new subdivisions and council plan changes. We plan to implement 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.

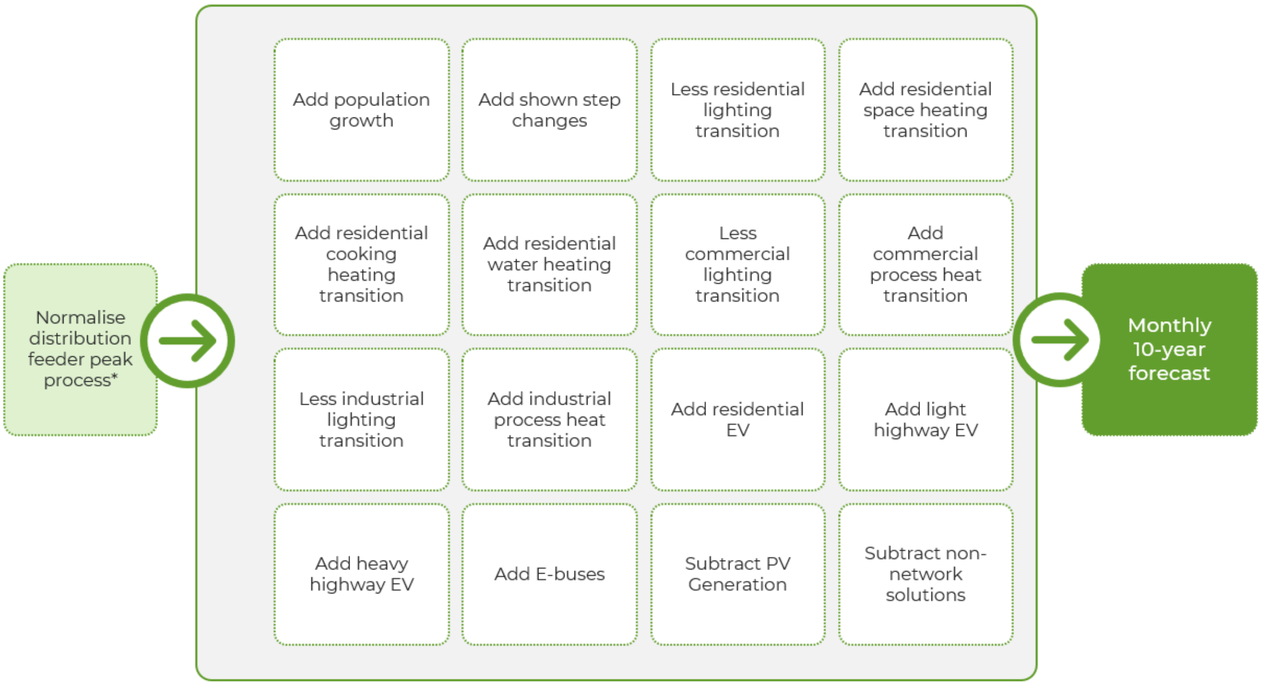
For the prudent forecast, we take the expected forecast and add extra growth to account for potential demand growth. For example, we might have allowed a 2 MW load for four years (0.5 MW each year) for the expected forecast; but with accelerated development, this may become 2 MW in two years.

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 Normalisation process:* Transferred load is added back to the donor substation, disregarding abnormal 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 the long-term (6–10 years). The uncertainty increases over longer forecast periods. This is influenced by many factors, including but not limited to the drive for decarbonisation, uptake of emerging/new technologies, regulations, and potential changes to the power system landscape accompanying increased utilisation of flexibility services.

Electrification of large transportation – for example, planes, ferries, 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. We are monitoring and collaborating with key contacts at the Port of Otago, Dunedin International Airport and Queenstown Airport.

NETWORK MODEL

We have created two geographical network models in PowerFactory modelling software, representing the Dunedin sub-network and the two other 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 given us the opportunity 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 on 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

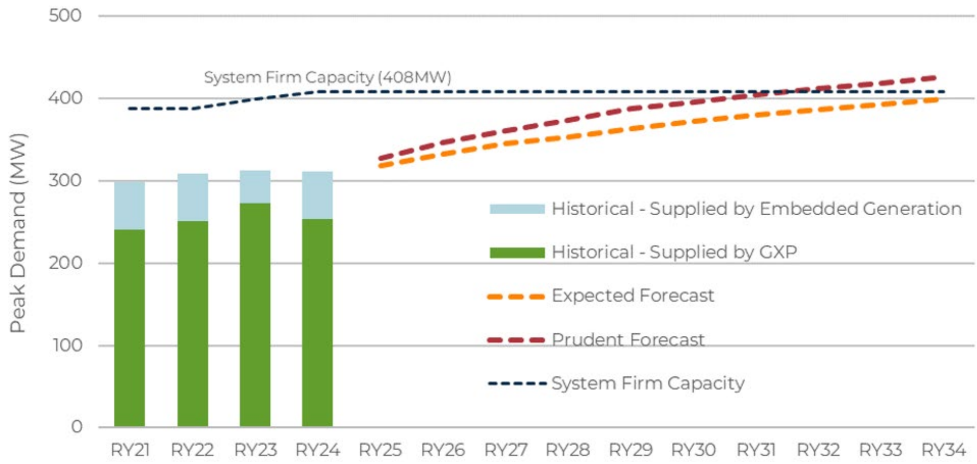
Using the demand forecasting approach described above, we also review actual historical demand. Table 10-2 outlines the total network historical demand broken down by GXP.

The system peak demand typically occurs in winter. This year's system peak demand was almost the same as last year's. After 2020 (affected by Covid), the system peak demand has continued to grow. Figure 10-3 shows the peak demand increasing from RY21. Generation reduces the system peak demand through the GXPs by an average of 17%. The peak demands of the GXPs are forecast to continue to increase.

Table 10-2: Historical peak demand

Maximum Demand	RY21	RY22	RY23	RY24
Halfway Bush	117.5	118.8	120.6	123.0
South Dunedin	75.0	75.0	72.9	73.1
Cromwell	43.9	46.5	49	48.8
Frankton	68.8	71.7	71.6	74.7
Clyde	18.8	18.2	19.3	20.0
Total system demand	**298.9**	**308.7**	**312.6**	**311.4**

Figure 10-3: Total system demand



The total system forecast indicates that demand will increase 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.

For our planned growth-related projects, see Appendix E.

10.5. DUNEDIN SUB-NETWORK INVESTMENT

The following sections show the demand forecast, network gaps, and expenditure for the Dunedin sub-network.

10.5.1. Halfway Bush demand

Halfway Bush GXP forecast capacity versus demand is shown in Figure 10-4.

Figure 10-4: Halfway Bush GXP forecast capacity

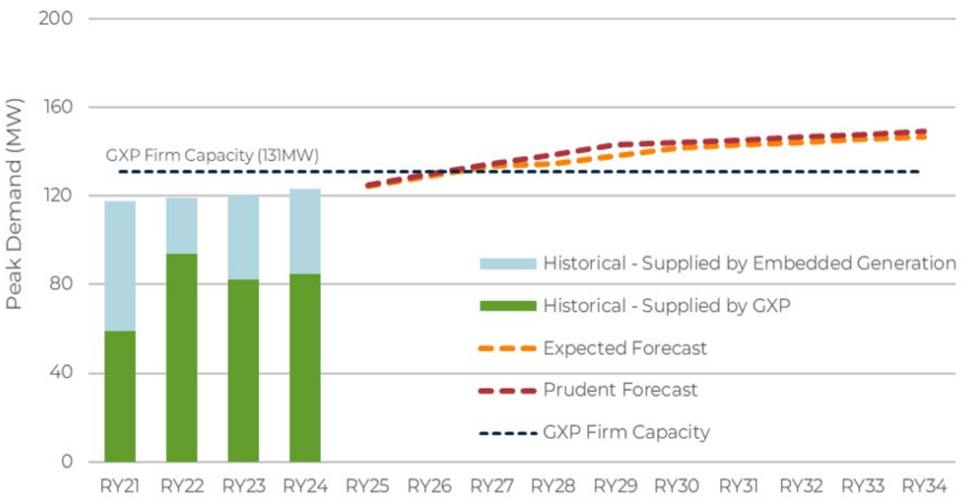


Table 10-3: Halfway Bush zone substations

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Berwick	Z3	N	2.7	1.4	1.6	**1.6**	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	Summer
East Taieri	Z1	N-1	22.9	18.7	18.0	**18.6**	18.9	19.3	19.5	19.8	20.1	20.3	20.6	20.8	21.0	21.2	21.4	Winter
Green Island	Z2	N-1	18	14.5	14.6	**14.0**	14.8	14.9	15.1	15.2	15.4	15.6	15.7	15.8	16.0	16.1	16.2	Winter
Halfway Bush	Z2	N-1	18	13.4	13.6	**13.9**	14.0	14.1	14.2	14.3	14.4	14.6	14.7	15.0	15.2	15.5	15.8	Winter
Kaikorai Valley	Z2	N-1	22.9	10.5	10.0	**10.6**	10.8	11.0	11.0	11.1	11.2	11.2	11.3	11.4	11.4	11.5	11.6	Winter
Mosgiel	Z2	N-1	12	7.2	7.1	**7.3**	7.3	7.4	11.7	11.8	11.9	12.0	12.0	12.2	12.3	12.4	12.5	Winter
North East Valley	Z2	N-1	14	10.4	10.4	**10.8**	10.9	11.0	11.1	11.2	11.3	11.4	11.5	11.6	11.7	11.7	11.8	Winter
Outram	Z2	N	7.5	3.2	3.3	**3.0**	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7	3.7	3.8	Winter
Port Chalmers	Z2	N-1	7.5	7.3	7.6	**7.7**	8.3	9.0	9.1	9.2	9.3	9.5	9.6	9.6	9.7	9.8	9.9	Winter
Smith Street	Z1	N-1	18	12.9	13.2	**12.6**	12.7	15.7	15.8	15.9	16.0	16.0	16.1	16.2	16.4	16.5	16.6	Winter
Ward Street	Z2	N-1	22.9	9.3	9.6	**9.5**	9.6	9.6	9.7	9.7	12.7	15.8	15.8	15.9	16.0	16.0	16.1	Winter
Willowbank	Z2	N-1	15	11.8	12.5	**12.9**	13.0	13.1	13.1	13.2	13.2	13.3	13.4	13.4	13.5	13.6	13.7	Winter

Historical demand

Forecast demand

N security zone substation if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

NETWORK GAPS

Key gaps between capacity and expected 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 would be above the firm capacity of the GXP. However, the Waipori generation offsets 30% of the GXP load. Decarbonisation plans of Port of Otago and Dunedin Airport will impact the capacity of the GXP. *Note:* Aurora Energy shares this GXP with OtagoNet.	We will conduct a study to understand the implication when whole or part of generation is out of service. We are in discussion with the Port of Otago and Dunedin Airport on their future plans.
Dunedin CBD 33 kV Subtransmission	Halfway Bush and South Dunedin GXPs both supply the CBD but have a very limited transfer capacity between GXPs. Most of the subtransmission circuits are in radial configuration and at 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 zone substations can be transferred between GXPs. Our preferred plan is combining the subtransmission cable renewal schedule with the creation of the subtransmission ring. The Smith St to Willowbank 33 kV cable is currently underway and is projected to be completed in RY25. This allows deferral of Willowbank gas cable renewal. The other projects scheduled at the later 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 requirement of electric ships and associated timing.

Area	Constraint	Status
Port Chalmers Substation	The peak demand of Port Chalmers Substation in winter 2023 was above the firm capacity and forecast to further increase. The transformers are planned for renewal in the latter part of the 10-year plan	The transformer replacement is brought forward to RY27–28 with larger size transformers to accommodate growth
Mosgiel Substation	Two large loads are expected to be connected within the 10-year plan in which the forecast indicates that the demand will be above the firm capacity. The substation is planned for renewal in the latter part of the 10-year plan	The rebuild of the substation is brought forward with increased capacity to cater for the expected large loads by RY28–30
Berwick Substation	Berwick Substation is an N-security level with limited backfeed supply from Outram. For contingent events such as zone transformer failure, restoration of power supply is dependent on repair time	Aurora has created a backfeed project to be completed in RY24 to provide backup supply from Outram. This would limit the outage duration to only switching time
Outram Substation	Outram Substation is an N-security level but has transfer capability to adjacent zone substations Outram Substation supplies the Dunedin Airport. Airport demand is likely to increase with decarbonisation	Aurora will prepare a contingency plan for loss of power supply We are working with Dunedin Airport on their decarbonisation plans

10.5.2. South Dunedin demand

South Dunedin GXP forecast capacity is shown in Figure 10-5.

Figure 10-5: South Dunedin GXP forecast capacity

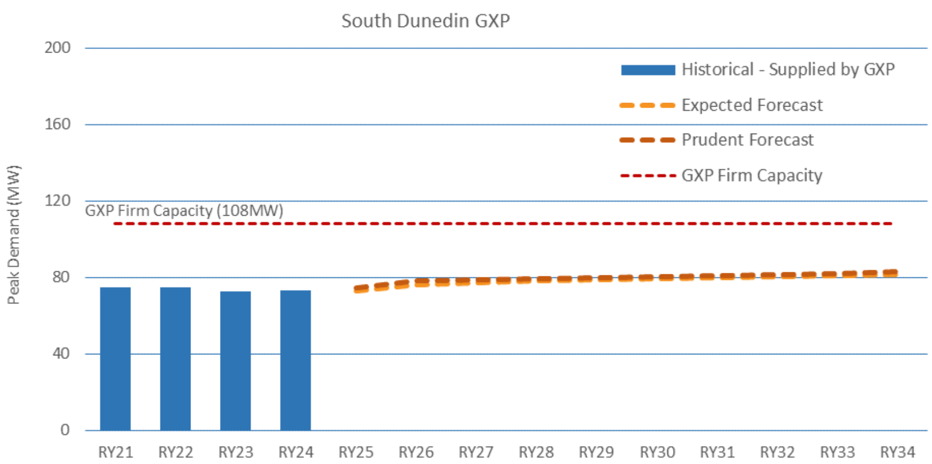


Table 10-5: South Dunedin zone substations

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Andersons Bay	Z1	N-1	24	15.5	14.2	**15.1**	15.3	15.6	15.9	16.1	16.3	16.5	16.6	16.8	16.9	17.1	17.3	Winter
Carisbrook	Z2	N-1	22.9	12.1	9.5	**10.5**	10.5	11.1	11.7	11.8	12.0	12.1	12.3	12.5	12.7	12.9	13.1	Winter
Corstorphine	Z2	N-1	19	12.9	12.0	**13.2**	13.2	13.3	13.5	13.7	13.8	14.0	14.1	14.3	14.4	14.5	14.6	Winter
North City	Z1	N-1	28	15.3	15.4	**16.2**	16.2	16.9	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.7	Winter
South City	Z1	N-1	18	15.1	14.8	**16.0**	15.9	15.8	15.8	15.8	15.8	15.8	15.9	15.9	16.0	16.0	16.1	Winter
St Kilda	Z1	N-1	22.9	14.6	14.6	**15.4**	15.6	17.7	17.9	18.0	18.1	18.2	18.3	18.5	18.6	18.7	18.8	Winter

Historical demand | Forecast demand | **N security zone substation** if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

10.5.3. 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 of having the subtransmission capable of supplying either Willowbank or Smith Street Substations 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
Mosgiel Substation Rebuild This project will replace the existing two 12 MVA transformer with 24 MVA transformers and replace the existing double 33 kV bus with a single indoor bus	2028	2030	8.4
Other Dunedin CBD 33 kV Subtransmission Projects			
South City to Ward Street	2031	2033	2.8
Smith Street to South City	2031	2032	3.5
South City to Carisbrook	2032	2034	6.2
North City to Ward Street	2033	2036	3.5

The distribution projects to be completed for the Dunedin sub-network are shown in Table 10-7.

Table 10-7: Distribution project for the Dunedin sub-network

Distribution Projects	From	To	Capex ($m)
Load transfer from St Kilda to Carisbrook This project is to offload St Kilda and increase capacity utilisation of Carisbrook substation	2031	2031	1.4

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 forecast capacity versus demand is shown in Figure 10-6.

Figure 10-6: Cromwell GXP forecast capacity

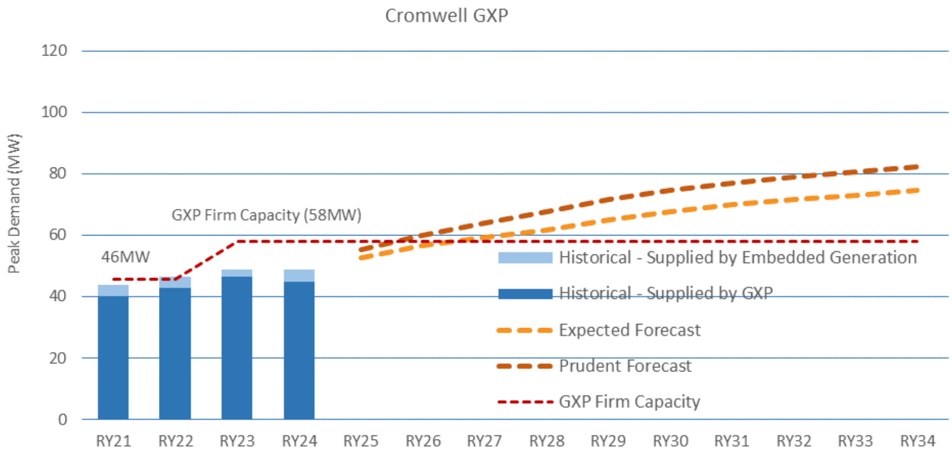


Table 10-8: Cromwell subtransmission

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Upper Clutha	Z1	N-1	33	30.5	34.5	**35.2**	38.5	41.3	43.1	45.0	47.5	49.4	50.9	51.9	52.8	53.6	54.4	Winter
		N-1	29	25.0	27.8	**30.6**	31.8	32.9	33.6	34.3	35.0	35.7	36.3	36.5	36.7	36.9	37.1	Summer

Historical demand | Forecast demand | **N security zone substation** if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

Table 10-9: Cromwell zone substations

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Camp Hill	Z2	N	7.5	5.5	5.7	**5.8**	6.2	6.6	6.9	7.1	7.3	7.5	7.7	7.8	7.9	6.1	6.3	Summer
Cardrona	Z3	N	24	3.7	3.9	**5.0**	6.8	7.8	8.3	8.9	10.3	10.9	11.2	11.3	11.3	11.4	11.5	Winter
Cromwell	Z2	N-1	24	13.8	14.4	**14.0**	16.7	17.8	18.5	19.2	19.9	20.6	21.3	22.0	22.4	22.9	23.4	Winter
Lindis Crossing	Z3	N	10	6.6	7.0	**8.5**	8.8	8.9	8.9	8.9	9.0	9.0	10.1	10.1	10.2	10.2	10.3	Summer
Queensberry	Z3	N	4	3.4	3.8	**3.4**	3.5	3.6	3.7	3.7	3.8	3.8	2.8	2.8	2.9	3.0	3.1	Summer
Wanaka	Z1	N-1	23.8	25.0	27.2	**25.5**	26.5	27.7	20.7	21.1	21.5	21.3	21.9	22.4	22.9	22.7	22.9	Winter
Riverbank	Z3	N	24						8.1	8.6	9.2	10.5	10.8	11.1	11.3	12.2	13.0	New substation
New Substation Luggate		N	7.5													3.2	3.4	New substation

Historical demand | Forecast demand | **N security zone substation** if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

10.6.2. Network gaps

Key gaps between capacity and expected 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 circuits supplies the GXP's two 3-winding transformers. There is no 220 kV bus. The 110 kV side supplies the FKN GXP through the CML-FKN transmission line. The 33 kV side supplies the Cromwell area	We are in discussion with Transpower and QLDC in regard to the future capacity requirement beyond the 10-year plan to ascertain expenditure decision-making As a tactical solution before the mid-term, Transpower and Aurora Energy has agreed to install a Special Protection Scheme (SPS) to allow the load to be above the firm capacity. This

Area	Constraint	Status
	The 33 kV firm capacity is 58 MVA (summer/winter) limited by the 33 kV cable between the GXP Transformer and the 33 kV outdoor bus Additional capacity is required from the midterm of the AMP period	solution provides an optimised expenditure per MVA of capacity increase
Upper Clutha 66 kV Subtransmission circuit	The two Upper Clutha 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 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 inconsideration of the line losses when one circuit is out-of-service Towards the latter part of the ten-year plan, forecast indicates additional capacity is required	Aurora Energy commissioned a SPS last year for winter and summer to allow load to be above the firm capacity Aurora Energy has been employing non-network capacity support to augment the capacity constraint. Aurora has partnered non-exclusively with solarZero to provide support during peak demand periods. This is part of the CPP approved Upper Clutha DER solution To increase capacity Aurora Energy is installing a new autotransformer of a higher rating and parallel the existing autotransformer by RY25 to have 40/43 MVA (summer/winter) capacity Aurora Energy has plans to construct a third circuit and create a 66 kV bus at Queensberry substation to cater for the forecast demand at the latter part of the ten-year plan
Wānaka zone Substation	The forecast indicates that the load will be above the firm capacity and continue to increase beyond the security of supply because of significant growth in the area	Aurora Energy has completed the load transfer project last year to provide 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 which is planned to be completed by RY25. In the long-term, we plan to install a second 24 MVA transformer at Riverbank when the load grows above the security level
Lindis Crossing and Queensberry zone Substation	Both zone substations are N-security level. We expect that developments in the area will increase the demand beyond the capacity of both substations	We plan in the short term to increase the capacity of Lindis Crossing by adding a second transformer rated at 24 MVA then offload Queensberry load. If the load continues to grow, we plan to replace the 10 MVA transformer with 24 MVA
Camp Hill zone Substation	The forecast indicates that by mid-term of the AMP period, the demand will be above the capacity of the transformer	Aurora has completed the load transfer project last year to provide capability to transfer >1.5 MVA between Wānaka and Camp Hill We are installing a 2 MVA generator to be utilised for emergency situations and is expected to be commissioned in RY25 We plan to install transformer fans to increase its capacity to 10 MVA in RY29 Further, we plan to construct a new substation in the Luggate area to cater for load growth and rationalise the long run of distribution feeders between Camp Hill, Queensberry and Wānaka to improve reliability

10.6.3. Clyde demand

Clyde GXP forecast capacity versus demand is shown in Figure 10-7.

Figure 10-7: Clyde GXP forecast capacity

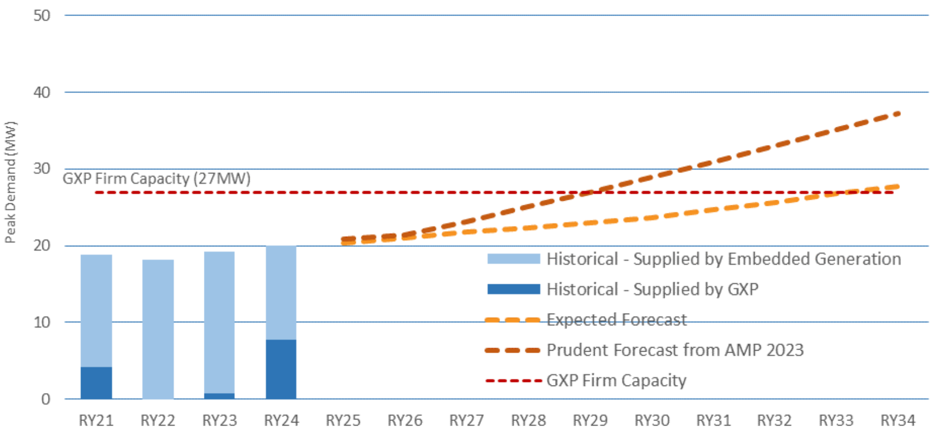


Table 10-11: Clyde subtransmission

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Alexandra - Omakau	Z2	N	4.8	4.0	4.2	**4.0**	4.7	4.9	5.1	5.4	5.8	6.1	6.4	6.7	7.0	7.3	7.6	Summer
Alexandra - Roxburgh	Z1	N-1	16	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
Clyde - Alexandra	Z1	N-1	13	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 zone substation if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

Table 10-12: Clyde substations

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Alexandra	Z2	N-1	15	10.8	11.5	**11.1**	11.5	11.7	12.0	12.4	12.7	13.1	13.4	13.7	14.0	14.3	14.6	Winter
Dunstan	Z3	N	24		0.0	**0.0**	0.0	0.0	0.0	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.1	New substation
Clyde/Earnscleugh	Z3	N	4.8	3.9	4.1	**4.2**	4.3	4.6	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Summer
Ettrick	Z3	N	3.6	1.9	2.2	**2.0**	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	Summer
Lauder Flat	Z3	N	3	1.0	1.2	**1.0**	1.3	1.3	1.4	1.4	1.5	1.6	0.0	0.0	0.0	0.0	0.0	Summer
Omakau	Z3	N	4	3.4	3.2	**3.2**	3.6	3.8	4.0	4.2	4.5	4.7	6.6	6.9	7.3	7.6	7.9	Summer
Roxburgh	Z2	N	5	2.0	1.7	**2.1**	2.1	2.1	2.2	2.2	2.3	2.4	2.4	2.5	2.6	2.7	2.8	Summer
Earnscleugh			2															

Historical demand
Forecast demand
N security zone substation if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

10.6.4. Network gaps

Key gaps between capacity and expected 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) 60% of last year's peak demand was supplied by embedded by generation	

Area	Constraint	Status
Alexandra-Omakau Subtransmission	The subtransmission is a single circuit that runs 24 km with small size conductors. This impacts the voltage limits and capacity towards Omakau and Lauder Flat Substations Demand continues to grow in the region and voltage constraints will need to be addressed	The plan is to increase capacity and security to the area. The subtransmission plan is to construct a second line with higher capacity to mitigate voltage drop then upgrade the existing subtransmission to the same capacity in two stages. This will be implemented via a staged approach over the long-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 site for the Clyde/Earnscleugh Substation	Stage 2 of the substation development is planned to be completed in RY26. After which, the Clyde/Earnscleugh distribution network will be transferred to Dunstan Substation. Once completed, the Clyde/Earnscleugh and Earnscleugh Substations will be decommissioned
Omakau Substation and Lauder Flat	Rebuild of Omakau is work in progress which is planned to be completed in RY24. The rebuild includes installation of a 2 MVA generator to provide emergency supply during a loss of the single subtransmission or the single transformer Both substations are at N security level. Omakau can provide back-up to Lauder Flat; however, this is not the same case with Lauder Flat. Further, load is growing in their service areas	The plan is to increase capacity and security to the area by transferring Lauder Flat to Omakau. Two existing feeders will be upgraded in two stages. A second transformer will also be installed in Omakau in RY27–28. The subtransmission plan is described above. Further, we plan to increase transfer capacity between Omakau and Alexandra substations.
Ettrick substation	Ettrick substation is at N security level. Ettrick is planned to be renewed midterm of the AMP period. The distribution network is supplied by a single feeder with limited transfer capacity	The plan is to rebuild the substation and increase capacity, reconfigure the distribution network to improve reliability and increase transfer capacity to Roxburgh substation

10.6.5. 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	**Upper Clutha new autotransformer (capacity event reopener)** Work in progress to install a new 50 MVA autotransformer and parallel the existing two autotransformer to increase capacity of the Upper Clutha circuit to 40/43 MVA (summer/winter)	2023	2025	5.1
	Riverbank zone substation (capacity event reopener) Work in progress to install a 24 MVA transformer at the Riverbank Switching Station to offload Wānaka substation	2024	2025	4.9
	Lindis Crossing Capacity Upgrade Stage 1 We will install a second transformer and extend the 11 kV switchgear which will cater for load growth, offload Queensberry substation and allow additional 11 kV feeders into the Bendigo area	2026	2028	3.9
	Upper Clutha new 66 kV line A new 66 kV line from Cromwell GXP to Cardrona substation will be built to increase capacity to the Upper Clutha region to cater for the significant load growth. *Note:* **This incorporates a component of renewals expenditure**	2025	2029	40.7

GXP	Major Projects	From	To	Capex ($m)
	Queensberry 66 kV bus The existing 66 kV tee off to supply Queensberry substation from the Upper Clutha circuit will be converted to a close bus with ground-mounted 66 kV CB on the tee off	2027	2028	4.1
	Camp Hill Transformer fans To increase transformer capacity, we will install fans to uprate the transformer from 7.5 MVA to 10 MVA	2029	2029	0.25
	Cardrona to Riverbank 66 kV line A new Cardrona to Riverbank 66 kV line will be constructed to increase further the capacity of the third Upper Clutha circuit. The existing line will be used as additional 11 kV intertie between Cardrona and Wānaka Substation	2030	2032	8.8
	Lindis Crossing Capacity Upgrade Stage 1 This project will replace the existing 10 MVA transformer with a 24 MVA transformer to increase the firm capacity to 24 MVA	2032	2033	3
Clyde	**Dunstan Substation Stage 2** Stage 2 development includes construction of the 11 kV switchgear building and installation on the switchgear	2026	2026	1.8
	Omakau second transformer Installation of a 24 MVA transformer and expand 11 kV switchgear with new feeders. These new feeders allow the transfer of Lauder Flat as described below	2027	2028	3
	Alexandra to Omakau Subtransmission stage 1 & 2 Construct a second subtransmission line with higher capacity and upgrade the existing line with the same capacity	2031	2034	15.1
	Ettrick Substation upgrade Upgrade the substation capacity with a 7.5 MVA transformer, install indoor switchgear and mobile substation bay	2031	2033	5.4

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	**Riverbank 11 kV feeders Stage 1 (capacity event reopener)** Reconfiguring the Wānaka feeders to become feeders of Riverbank Substation and offload Wānaka. The reconfigured network will have interconnection between the substations	2024	2025	1.3
	New Cromwell 838 Feeder Stage 2 & 3 Reconfiguring the Cromwell distribution network to increase security level and reliability	2026	2026	0.8
	Cromwell 832 Feeder reinforcement Reconfiguring the Cromwell distribution network to increase security level and reliability	2027	2027	1.5
Clyde	**Alexandra new feeder** Install a new feeder cable to offload an existing feeder which increases transfer capacity between Alexandra and Clyde/Earnscleugh. The existing feeder also increases the transfer capacity between Alexandra and Omakau with the project described below	2024	2025	0.8
	Reconfigure Clyde/Earnscleugh distribution network Distribution component of Dunstan Substation. Transfer the distribution network to Dunstan Substation and reconfigure the network to increase reliability	2026	2027	3

GXP	Distribution Projects	From	To	Capex ($m)
	Lauder Flat security upgrade stage 1 & 2 Supply Lauder Flat from Omakau Substation with two feeders using the existing lines	2026	2029	2.7
	Transfer load from Omakau to Alexandra Substation Increase transfer capacity between Omakau and Alexandra and offload Omakau	2030	2031	5.6
	Ettrick network reconfiguration Reconfigure the network to increase security and reliability, and transfer capacity to Roxburgh	2033	2034	1.5

10.7. QUEENSTOWN SUB-NETWORK INVESTMENT

10.7.1. Frankton demand

Frankton GXP forecast capacity versus demand is shown in Figure 10-8.

Figure 10-8: Frankton GXP forecast capacity

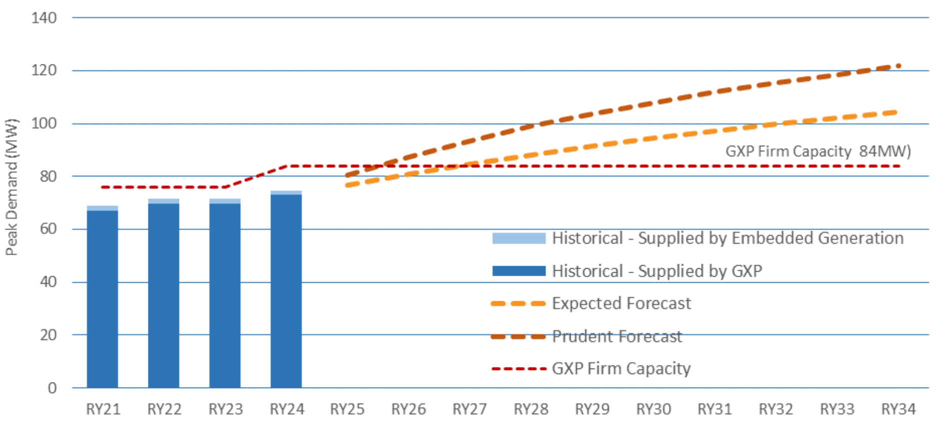


Table 10-16: Frankton Subtransmission

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Arrowtown Ring	Z1	N-1	30	17.5	17.9	**17.8**	18.2	19.7	20.3	21.0	21.4	22.8	23.2	27.7	28.3	28.8	34.4	Winter
Queenstown	Z1	N-1	35	29.4	30.9	**31.5**	32.0	33.2	34.6	36.0	37.4	38.5	39.3	40.1	40.9	41.7	42.5	Winter

Historical demand

Forecast demand

N security zone substation if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

Table 10-17: Frankton zone substations

Zone substation	Security class	Security level	Firm capacity (MVA)	Historical			Forecast											Peak period
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	
Arrowtown	Z2	N-1	10	9.4	9.7	**9.6**	9.8	10.1	10.6	11.0	11.4	9.9	9.1	9.3	9.6	9.8	0.0	Winter
Commonage	Z2	N-1	15		11.6	**11.8**	11.9	12.0	12.2	12.4	12.6	12.8	13.0	13.3	13.5	13.7	13.9	Winter
Coronet Peak	NA	N	6	5.4	5.1	**5.2**	5.2	5.2	5.2	5.2	5.2	0.0	0.0	0.0	0.0	0.0	0.0	Winter
Dalefield	Z3	N	3.6	1.7	1.7	**1.7**	2.0	3.2	3.5	3.8	3.9	0.0	0.0	0.0	0.0	0.0	0.0	Winter
Fernhill	Z2	N-1	10	5.9	6.3	**6.5**	6.7	7.0	7.3	7.7	8.8	9.0	9.2	9.3	9.5	9.7	9.9	Winter
Frankton	Z1	N-1	15	17.1	18.0	**18.2**	18.9	19.8	20.9	21.9	23.0	23.0	24.0	25.0	25.8	26.5	27.2	Winter
Queenstown	Z2	N-1	20	12.2	12.4	**12.7**	12.9	13.7	14.6	15.5	15.6	16.2	16.7	17.1	17.5	17.9	18.1	Winter
Remarkables	NA	N	3.6	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	N-1	24									9.9	10.9	11.1	11.3	11.5	11.7	Winter
Whitechapel	Z1	N-1	24														10.2	Winter

Historical demand | Forecast demand | **N security zone substation** if forecast demand > 70% of the stated capacity OR **N-1 security zone substation** if forecast demand > 110% of the stated firm capacity

10.7.2. Network gaps

Key gaps between capacity and expected 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 is supplied by the 110 kV CML–FKN line. There is no 110 kV bus at FKN The GXP capacity is limited to 84 MVA. The forecast indicates that in the next 2-3 years the load will be above the limit The next constraint is the 110 kV transmission line, which is limited by line loading at 77 MW	Aurora Energy, PowerNet and Transpower are progressing the replacement of the existing GXP transformers with 120 MVA transformers to be completed by 2025 Aurora Energy and PowerNet has engaged Transpower to conduct a study to increase transmission line capacity. Implementation of thermal upgrade is planned to be completed by RY27
Queenstown Subtransmission	The forecast shows that the peak demand will be above the firm capacity from mid-term of the AMP period	We will upgrade the limiting section of circuits 1 & 2 to increase the capacity We will seek non-network support through an Open Call for non-network capacity
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
Dalefield Substation	Dalefield and Arrowtown Substations supplies 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 (N security) and Arrowtown Substation (N-1 security) in the planning period In the mid-term, the forecast indicates the demand will be above the capacity of the said substations	Aurora Energy will construct a new substation (Malaghans) with a firm capacity of 24 MVA to cater for the expected growth The plan is to bring across Coronet Peak ski field to the new substation and decommission its substation. The existing Dalefield Substation will also be decommissioned. Further, the plan is to transfer some load of Arrowtown substation The transfer allows deferral of 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

Area	Constraint	Status
Frankton Substation	The load is above the N-1 capacity and will continue to increase driven by significant growth	Work in progress to replace the existing 15 MVA transformer with 24 MVA transformer to be completed by RY25. This increases the firm capacity to 24 MVA Toward the latter part of the 10-year plan, the demand will breach the 24 MVA firm capacity. We have developed potential solutions at this stage to cater for the potential demand increase in Queenstown Airport driven by decarbonisation and developments on the southern part of Frankton. Depending on when demand eventuates, new capacity injections will offload Frankton Substation We have also planned to reconfigure the distribution network to increase reliability and operability
Fernhill Substation	The forecast indicates the demand will be within the firm capacity at the end of the 10-year planning horizon	We are investigating options for the wider area from Queenstown to Glenorchy, which will involve the substations at Queenstown, Commonage and Fernhill Initial plan is to transfer the Glenorchy load from Queenstown to cater for the large development in Queenstown

10.7.3. 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 in progress to install a new 24 MVA transformer to replace the 15 MVA transformer to increase firm capacity to 24 MVA	2024	2025	1.6
Malaghans Substation Construct a new substation with indoor 33 kV and 11 kV switchgear building and outdoor installation of two 24 MVA transformers. The new substation will replace the Dalefield and Coronet Peak Substations	2025	2026	10.9
Fernhill Substation additional 11 kV Circuit Breakers To allow for the Glenorchy feeder transfer from Queenstown, additional circuit breakers will be installed	2026	2027	1
Queenstown Subtransmission capacity upgrade The limiting section of Queenstown Subtransmission circuits 1 & 2 will be replaced to increase capacity	2028	2029	4.3
Whitechapel Substation This substation will replace the Arrowtown Substation. The new substation will have indoor 33 kV and 11 kV switchgear building and outdoor installation of two 24 MVA transformers	2030	2032	8.1
Lake Hayes Subtransmission cable upgrade The limiting section of the Arrowtown Subtransmission circuit will be replaced to increase capacity	2033	2034	1

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)
Frankton 11 kV cable across Shotover bridge The existing feeder to Lake Hayes has high load and has limited offloading options. This project will resolve this constraint and also cater for future developments in the area	2026	2027	1
Queenstown Feeder Reconfiguration Stage 1 Load on the existing feeder that supplies Gorge Road is increasing and this feeder provides backup supply to Arthurs Point. This project will resolve this constraint and increase transfer capacity	2027	2028	0.7
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	2027	2028	5.4
New Frankton Feeder One of the feeders is highly loaded and the Frankton 11 kV bus has an unequal loading. This project will split the highly the loaded feeder and would result to have the bus equally load to assist in load transfer	2027	2027	0.7
Frankton Southern Corridor cable Growing load at Jacks Point will impact the 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	0.6
New Fernhill Feeder This is the distribution component of the new 11 kV circuit breaker at the substation to transfer Glenorchy load to Fernhill	2028	2028	0.9
Frankton Arm 11 kV feeder The load in the Kelvin Heights area is increasing and is supplied only by a single feeder from Frankton with no transfer capacity. This project will bring the level of security to the are based on Aurora's security of supply guidelines	2028	2029	1
New Commonage Feeder The existing two feeders of Commonage are highly loaded and is limited by the existing cable size. This project will divide the load of the feeders and provide transfer capacity	2029	2030	2.5

D

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 enables the best opportunity for enhancing resilience and reliability, while minimising risk to both personnel and public safety, for the least cost.

11.1. OVERVIEW

Section 6.5 of this AMP describes the approach and strategies we apply to Asset Lifecycle Management. In this chapter, we describe in more detail, how the approach is applied to our assets and summarise resulting renewal and maintenance plans by asset fleet.

This section provides an overview of our network assets, by portfolio and by fleet. The age, condition, performance and risk profiles are indicative of key considerations documented in more detail in our *Fleet Strategies*. These are 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 31 March 2024 (unless specified otherwise).
- 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 G.

11.1.1. Asset portfolios

Aurora Energy owns and operates a substantial network of assets to supply electricity to 93,600 customers. Our current categorisation of assets has 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 the team 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', ancillary distribution substation assets in 'Distribution Substations and Transformers')
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/fleets, from a complexity and management perspective, we provide more detail in the relevant fleet-specific sections.

11.1.2. Fleet strategies

The 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
- Spare 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

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 AM objective (bold). Each of our Fleet Strategy documents captures the line of sight from AM 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 constraint
	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 our 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 contractor of systemic issues
	We provide an avenue of 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
Reliability to defined levels	**Reliability improvements are achieved by refined management of assets**
	Our outages caused by condition-driven failures are trending downward

Asset Management objective	**Key Asset Management Objectives** Portfolio Objectives
	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 **Manage planned outages to reduce impact upon consumers** We take into account the potential impact upon 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 to 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 undertake QA 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 solution to improve cost outcomes** We measure asset performance and investigate new/alternative materials and manufacturers to ensure value in our investments, reduce management costs and increase life expectancies
Responsive 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 measure the impacts of such decisions **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

Asset Management objective	**Key Asset Management Objectives** Portfolio Objectives
	- 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** Negative environmental impact is minimised We explore OHUG as part of our reconductor options analysis Our investment decision-making considers the long-term sustainability of our business **We evaluate the implications of the disposal and making good processes in our whole of life considerations** Environmental criticality is factored 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 Disposing of assets responsibly, and reusing them where practical to benefit the community Applying good industry practice and reporting for management of hazardous substances, including oil and SF_6 Minimising spills and leaks of oil and SF_6 from all assets, and ensuring all leaks are fully contained Pursuing opportunities to increase network resilience through management of seismic risk and uprating of assets where economically viable Maintaining comprehensive, up-to-date, and readily accessible asset data—including for secondary and protection settings—in an effective and controlled asset information system Minimising interruptions and inconvenience to the public when undertaking asset repairs or renewals, and planning consolidated works with other utilities Mitigating 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	Inspection programmes designed to identify onset of failure modes Preventive maintenance activities informed by inspection results, understanding or risk, failure modes and supplier recommendations where applicable Corrective maintenance informed by inspections, defects or faults Identification of safety risks to our workforce and the public in a timeframe appropriate with the risk Minimisation of vegetation-related safety and environmental risks Improved education around risks associated with vegetation near conductor
Reliability to defined levels	Consideration of planned outage reliability limits when planning outages for preventive maintenance Remediation of defective or deteriorating components in an appropriate timeframe to minimise unplanned service interruptions Reduction in risk of vegetation-related events damaging network equipment, to minimise the impact of vegetation on reliability performance Reduction in planned outages by targeting vegetation trimming and ensuring such work is aligned with other activities
Affordability through cost management	Minimisation of whole-of-life costs by undertaking corrective work based on well-informed Opex/Capex trade-offs Ensuring economies of scale by undertaking multiple works in a coordinated manner Improvement of vegetation management cost efficiency and programme effectiveness Reduction in the occurrence of vegetation-related faults and related expenditure Expanding our feeder-based approach to inspection and testing to other network assets for greater efficiency and improved asset data Increase understanding of failure causes with a view to better targeting preventive and corrective maintenance activities Identify systemic causes of failure to inform more effective maintenance and inspection activities Use technology to assist in vegetation management planning and improve efficiency
Responsive to a changing landscape	We use RCA 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 Identify and remediate environmental risks and issues before they become unacceptable to stakeholders Minimise landowner disruption as much as reasonably practicable 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 the appendices. The reported data accuracy scale of 1–4, is in accordance with the scale defined by the Commerce Commission at https://comcom.govt.nz/.

1 - Means that good quality data is not available for any of the assets in the category and estimates are likely to contain significant error

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 assets in the category

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 IBM Maximo, which will be the repository for our asset data. Data confidence will grow as we expand on 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[5]
Support structures	Poles	GIS	A direct connection to GIS used to provide the asset-specific information that links the pole to other assets	3
	Crossarms	GIS	A direct connection to GIS used to provide all asset information	2[6]
Overhead conductor	Subtransmission 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

[5] 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 error
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

[6] Note that the confidence score of 2 given here differs from the score given in Schedule 12. This updated score reflects our revised understanding based on data ascertained through new overhead inspections conducted over the last six months.

Portfolio	Asset Fleet	Primary Data Source	Source Description	Condition Data Confidence Level[5]
	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
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	GIS	A direct connection to GIS used to provide all asset information	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	GIS	A direct connection to GIS 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	GIS	A direct connection to GIS used to provide all asset information	3

Portfolio	Asset Fleet	Primary Data Source	Source Description	Condition Data Confidence Level[5]
	Ancillary distribution substation equipment	GIS	A direct connection to GIS used to provide all asset information	3
Distribution transformers	Ground-mounted distribution transformers	20230703 DTX Fleet Strat File	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME	3
	Pole-mounted distribution transformers	20230703 DTX Fleet Strat File	A manual spreadsheet giving a more complete view of the asset information. Actively maintained by SME	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
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 fall into one of 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, while 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, and trends which 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, which is included in our SONS portfolio.

11.2.1. Preventive maintenance

Preventive Maintenance activities are predetermined activities, including 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 the 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 F.

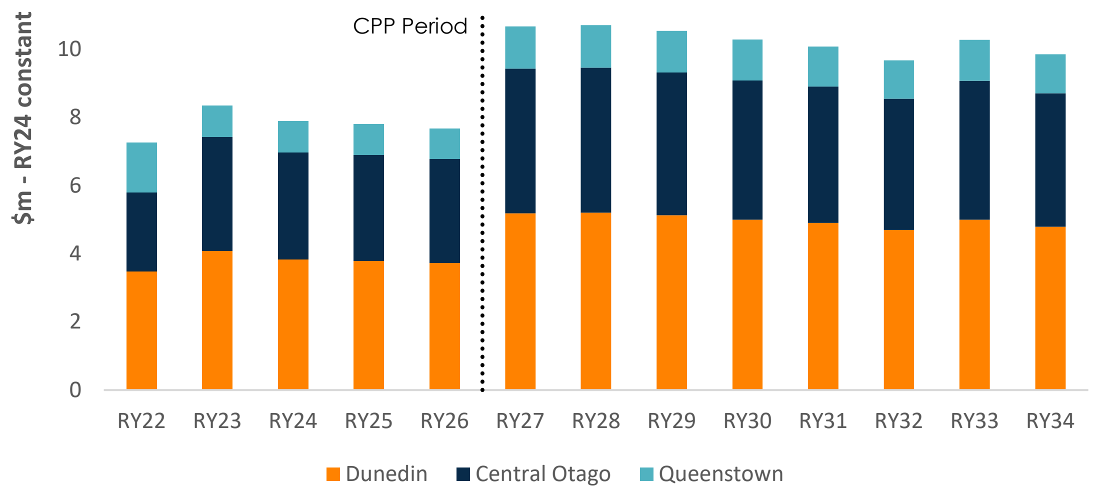
The Base forecast for preventive maintenance is calculated by analysing the expenditure in the nominated 'base year' (the last full year of data at the time of putting the forecasts together). As part of our continuous improvement work to better understand asset condition and respond to root cause fault information, we have made step changes in our preventive maintenance forecast. Key steps and trends incorporated into our Preventive Maintenance Plan include:

- Introduction of a visual and thermal overhead inspection programme of $2.8 million in the DPP4 period. This includes a reduction of $1.2 million associated with disestablishing our ABS inspection programme, which is now incorporated into the new overhead programme. This programme has been 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 $0.75 million in the DPP4 period.
- Enhanced distribution switchgear inspections to enable deferral of switchgear renewals. This cost declines over time as we progress our switchgear renewal programme. Forecast increase of $2 million in the DPP4 period.
- Introduction of a lidar survey in RY27 and RY29. Forecast increase of $1 million in the DPP4 period.
- $1.8 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 1.13% 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.

For a summary of our preventive maintenance activities by fleet, refer to Appendix F.

Figure 11-1: Preventive maintenance Opex forecast by region (RY24 constant, $m)



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 (RY23 constant, $,000s)

Asset Portfolio	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Support Structures	2,326	2,113	2,295	2,867	2,986	2,767	2,886	2,651	2,731	2,711	2,793
Overhead Conductors	506	818	827	1,360	846	1,391	866	1,422	885	1,455	905
Underground Cables	177	164	153	220	236	220	226	208	210	213	215
Zone Substations	1,358	1,257	1,178	1,691	1,813	1,688	1,735	1,598	1,616	1,634	1,653
Distribution Switchgear	2,411	2,426	2,262	3,149	3,342	3,093	3,151	2,891	2,905	2,919	2,933
Distribution Transformers	938	868	814	1,168	1,253	1,166	1,199	1,104	1,116	1,129	1,142
Secondary Systems	171	159	149	213	229	213	219	202	204	206	209
Total	**7,887**	**7,804**	**7,678**	**10,669**	**10,705**	**10,537**	**10,282**	**10,075**	**9,667**	**10,267**	**9,850**

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 the 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 as per the base plan.

Step and trend changes incorporated into the corrective maintenance forecast include:

- Consumer pole remediation: This contributes significantly to the plan in the period from RY25–RY29
- Deferred/rollover maintenance: Forecasting deferral of maintenance from RY25 and RY26 years, out into RY28, RY29 and RY30

[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.

- Increased defect discovery and remediation from enhanced ring main unit (RMU) inspection regime
- Increased crossarm and conductor defect find rate due to an area prioritised acoustic inspection programme
- Allowances for increase in labour cost: New contract for field services (FSA2)
- Application of Commerce Commission 2019 trend factor for change in network scale of 1.13% per annum to our forecast

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.

Figure 11-2: Corrective maintenance Opex forecast by Region (RY24 constant, $m)

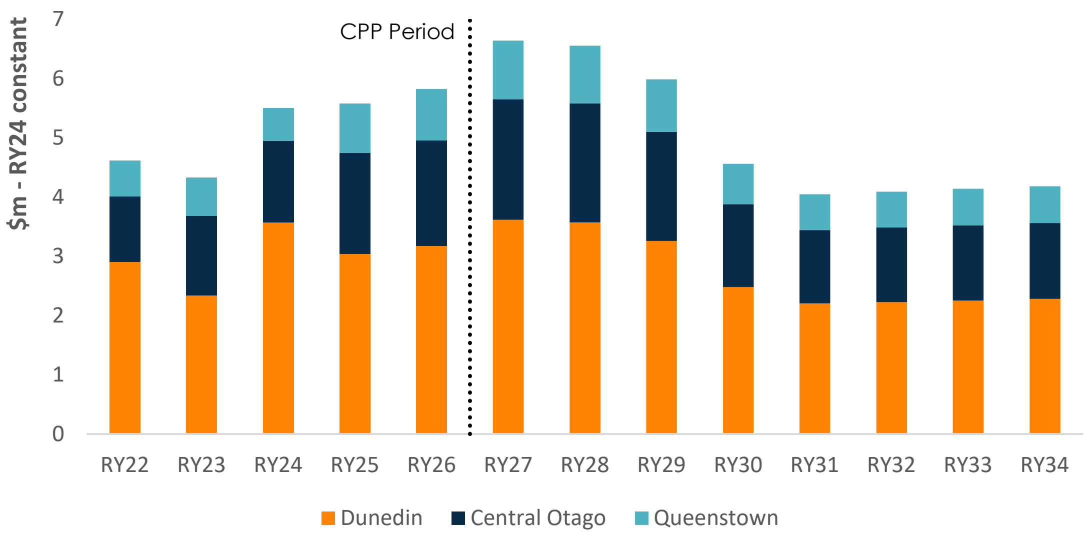


Table 11-6: Corrective maintenance Opex forecast by portfolio category (RY23 constant, $,000s)

Asset Portfolio	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Support Structures	1,159	2,912	3,323	3,450	2,911	2,302	816	758	766	775	784
Overhead Conductors	191	150	140	181	207	210	213	186	188	190	193
Underground Cables	539	424	396	510	585	592	601	525	531	537	543
Zone Substations	1,296	1,020	953	1,227	1,407	1,423	1,446	1,264	1,278	1,293	1,307
Distribution Switchgear	736	602	570	705	795	804	816	728	736	745	753
Distribution Transformers	395	311	291	374	429	434	441	385	390	394	398
Secondary Systems	205	161	151	194	222	225	228	200	202	204	206
Total	**4,520**	**5,580**	**5,824**	**6,640**	**6,556**	**5,989**	**4,560**	**4,046**	**4,092**	**4,138**	**4,185**

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'. This is not favourable in most cases, and can reflect the effectiveness of the asset management and asset maintenance strategies. We note that over the long-term there has been a downward trend in the number of faults, which reflects the improved asset management practices that we have established.

However, there are also external influences that will continue to drive the need for reactive maintenance: events such as storms have a significant impact and create significant volatility from year to year, as shown in the figure below. Events that may require a reactive response include adverse weather/storm damage, asset failure/imminent failure, vehicle or other third-party damage, network field switching associated with repair work, and dispatched response to alarms.

Figure 11-3 shows the historical fault numbers have been reducing over time.

Figure 11-3: Historical fault numbers (RY14–23)

The amount of work we undertake in other maintenance or renewal portfolios affects reactive maintenance volumes in the longer term. For example, Figure 11-3 indicates that an increase in renewal work on the overhead network has helped to decrease reactive maintenance volumes as it improves the condition of assets. 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 per 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 approaches to address emerging issues, step changes for new requirements, and escalation to account for growth of the network.

The Base expenditure is informed by historic 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.

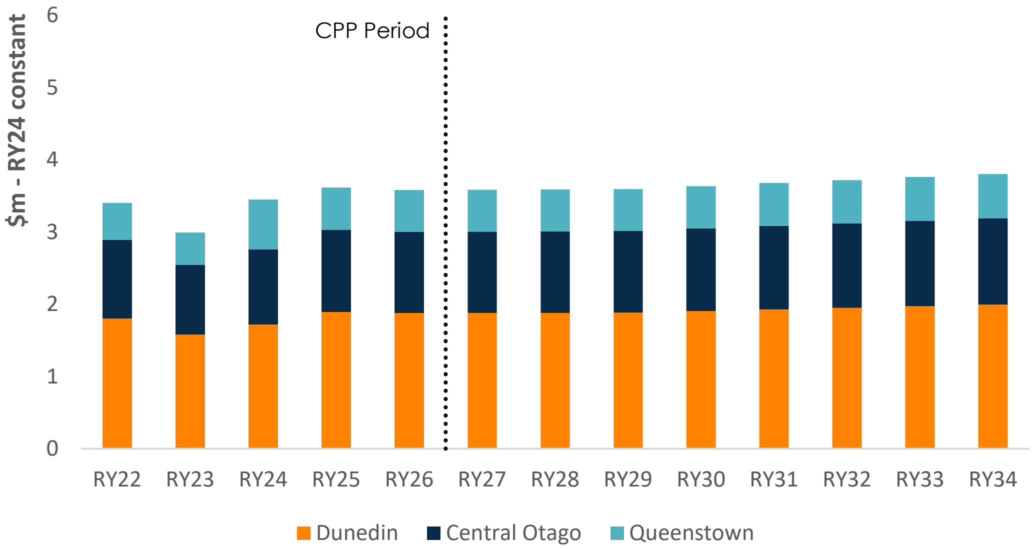
Step and trend changes incorporated into the reactive maintenance forecast include:

- Allowance for cost associated with enhanced contractor stand-by requirements to enable better fault response
- A trend assumption regarding improved network performance

[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.

- We have applied the Commerce Commission 2019 trend factor for an increase in network scale of 1.13% per annum
- Allowances for increase in labour cost: new contract for field services (FSA2)
- Application of Commerce Commission 2019 trend factor for change in network scale of 1.13% per annum to our forecast.

Figure 11-4: Reactive maintenance Opex forecast by region (RY24 constant, $m)



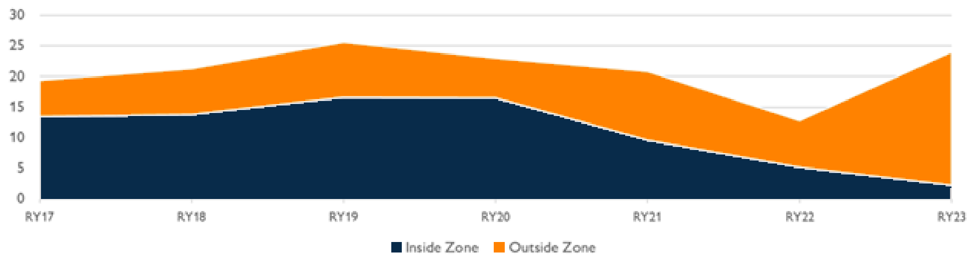
11.2.4. Vegetation management

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. Vegetation 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. As part of this programme, we perform regular inspections of our overhead network to identify network growing close to overhead lines. We also face additional costs to ensure that 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 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 covered in the regulations, has significant potential to affect reliability performance in the future.

Figure 11-5: Vegetation SAIDI performance — Inside zone vs Outside zone



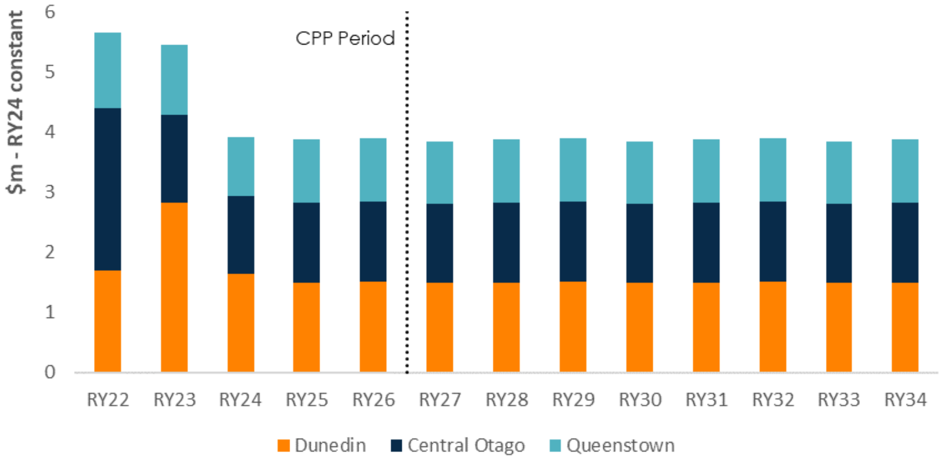
Our historical approach was largely reactive, whereby crews responded to issues as they were identified by line inspections, third-party reports, or network faults. In March 2022, we completed an initial round of inspection and maintenance across the network, and we have now moved to a three-year cycle to ensure that vegetation remains in a maintained state. In some locations where there are more critical assets or fast-growing vegetation, we complete 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 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 PR24, indicating that we expect to trim or remove less vegetation than in previous years, and we also anticipate transferring a greater share of costs towards tree owners for trees requiring a second cut, as per the Tree Regulations. As a result, we are now moving into a steady-state management programme and forecast lower vegetation management expenditure.

Figure 11-6: Vegetation maintenance Opex forecast by region (RY24 constant, $m)



There are some areas where there is potential for changes to regulations or a need to change our management approach based on an assessment of risk. These potential changes, listed in Table 11-7, are not currently included in our cost forecast; however, any change to the regulations or continued impact of 'fall zone' trees may result in additional costs.

Table 11-7: Vegetation management future revisions

Potential change	Description
Updated Tree Regulations	The current regulations were published in 2002. As of writing, MBIE are conducting a review, and we anticipate changes in the early part of the planning period. We may face a change in the scope of our programme to comply with new regulatory requirements.
Second cut costs	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 RY24.

Potential change	Description
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 we 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 we experienced an increase in SAIDI from out of zone vegetation. If these risks present an ongoing reliability concern, we will look to additional expenditure to address the 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. To facilitate a possible change in strategy we have begun to investigate the role of 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 thus continually review the performance of the network and effectiveness of our maintenance activities. This means seeking to optimise the level of expenditure needed to manage safety and reliability risk.

We are looking at advancing our understanding of certain failure modes, so that we can optimise timing and thus cost associated with intervention strategies; either maintenance or renewals. We are also looking at technologies that enable us to assess 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 working on enhancing our understanding of how our assets perform and fail, so that we have greater understanding of failure modes and failure rates – all of which we will use to drive optimised expenditure, from both a renewal and maintenance perspective.

The following are some of the key initiatives that we are currently implementing/ progressing.

LEANING POLES

Through 2023, Aurora Energy has actively participated in an industry-led study aimed at establishing evidence-based rules for evaluating pole lean, 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, we have (RY24) identified poles that were being tagged for renewal based on lean only, and undertaken individual engineering assessments, in some cases confirming that renewal can be deferred. We have also taken some learnings that are more specific, from the subsequent stages of the study. Applying this in practice will make our inspection more complex; meaning we need to build additional functionality in our inspection application. This is being assessed by our ICT team. We are working towards, being positioned to fully implement the updated lean assessment framework during RY25.

We anticipate that this will result in a more targeted focus on poles requiring rectification, whether through straightening or replacement. This initiative underscores Aurora'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.

MID-CYCLE INSPECTION FOR H2 POLES

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.

VONAQ TESTING

Aurora relies on the MPT testing system as its primary method for assessing pole conditions, which has proven to be a reliable tool. However, this system comes with notable drawbacks – in particular, the weight of the hardware 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 if the system would provide us with continuity of assessed conditions of Aurora Poles.

Thus far, positive results have emerged from the Vonaq testing system, and ongoing trials are planned for RY25. This reflects Aurora's commitment to staying at the forefront of technology and adopting solutions that enhance efficiency, add to our tool kit, and also address the physical demands on inspectors during the evaluation of pole conditions.

OVERHEAD INSPECTION SYSTEM

In 2023, Aurora unveiled an advanced overhead inspection system featuring a new IT platform, Survey123, along with an updated comprehensive Overhead Inspection Standard. This system represents a significant leap forward, introducing a streamlined approach that greatly improves the precision and data quality in the assessment of poles, crossarms, and conductors. Aurora plans to make additional enhancements to the system in RY25.

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 at 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. Proactively identifying failing assets enables a managed intervention before the asset fails, which typically has a higher consequence such as a longer and a more widespread outage and higher risk. Typical defects identified are:

- Cracked/broken insulators/bushings
- Insulator contamination
- High resistance connections
- Broken conductor strands
- PD on cable terminations
- Failing binders
- Vegetation interference

The Dunedin sub-network has a high volume of roadside assets in a reasonably compact coastal environment. As such, based on the value ascertained from previous acoustic inspections, we have decided to carry out ongoing biennial acoustic inspections of the complete Dunedin sub-network.

We have also implemented a springtime annual acoustic inspection on 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 in certain circumstances: Aurora Energy has carried out two acoustic inspections on parts of the Dunedin sub-network targeting feeders with the highest faults per kilometre that meet the location and asset type requirements for acoustic inspections, with positive results.

EARLY FAULT DETECTION SYSTEM

The early fault detection 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 of emerging faults and thereby enabling proactive intervention prior to failure. The technology has been trialled and is now being used successfully in both Australia and America.

The technology consists of solar powered EFD collection units installed on the overhead line feeder positioned at 4-5 kilometre spacing. These units detect signals and measure their energy and arrival time, communicating to an EFD portal server via 3G or 4G.

The software carries out analysis using algorithms that calculate signal source and strength to identify emerging faults to within 10 metres location accuracy. 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.

We are installing the technology on the OM33 feeder and are expecting to complete the work in Q4 RY24.

The OM33 feeder is a radial subtransmission feeder with N security (meaning that there is no back up 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. The estimated Volume of Lost Load (VoLL), assuming a typical four-hour outage, is $240,000.

The expected benefit is an improvement in SAIDI and SAIFI to consumers where the technology is deployed, as well as a reduction in the risk of property damage and/or injury arising from an overhead asset failure.

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 (RCA)

A comprehensive understanding and record of how, why, where, and when assets and their components fail is critical information for building a robust asset management framework.

In RY24 we established an equipment failures database to record RCA information from 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. The learnings enable improvements in inspection frequencies and techniques, which in turn inform asset health and emerging asset failures, thereby facilitating proactive intervention. The learnings also enable improvements in design and construction methodologies and material choice. Learnings this year 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. The medium-term intent is to establish a library of failure modes, and also to lock in an associated process once this has been fully refined.

ABS NEMA

Aurora Energy has recently reviewed and updated its approved materials choice of ABS. Failure of three recently installed new ABS devices where the likely root cause was manufacturing errors, alongside ongoing systemic issues identified in inspections and on other failures, prompted us to review other options and subsequently initiate a New

Equipment or Material Approvement (NEMA). The key steps undertaken in a NEMA are:

- Options review
- Advantages/disadvantages
- Financial evaluation

Following on from the approval of the new ABS, standards and documentation are being updated and issued with a view to deploying the new switch on the network in early 2024.

11.3. SUPPORT STRUCTURES

This section describes our support structures portfolio and summarises how we manage the following two 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.

Adequate performance of support structure assets is essential 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 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 1,767) 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. They 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 types. There is no single method to reliably assess all aspects of the condition of wood poles; we have developed and refined the framework and the tools that we use to test and understand evaluate 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 – the pole are cold formed hollow steel poles, of various height, diameter and thickness. There are also some legacy 'rail iron' poles in service.

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	8291	7167	1804	17262
Softwood Pole	2312	2260	950	5522
Concrete Pole	18419	8959	1711	29089
Steel Pole	351	1246	170	1767
Total	**29,373**	**19,632**	**4,635**	**53,640**

The rating of a pole is typically based on the highest voltage asset attached to it. Table 11-10 summarises our population of poles by voltage.

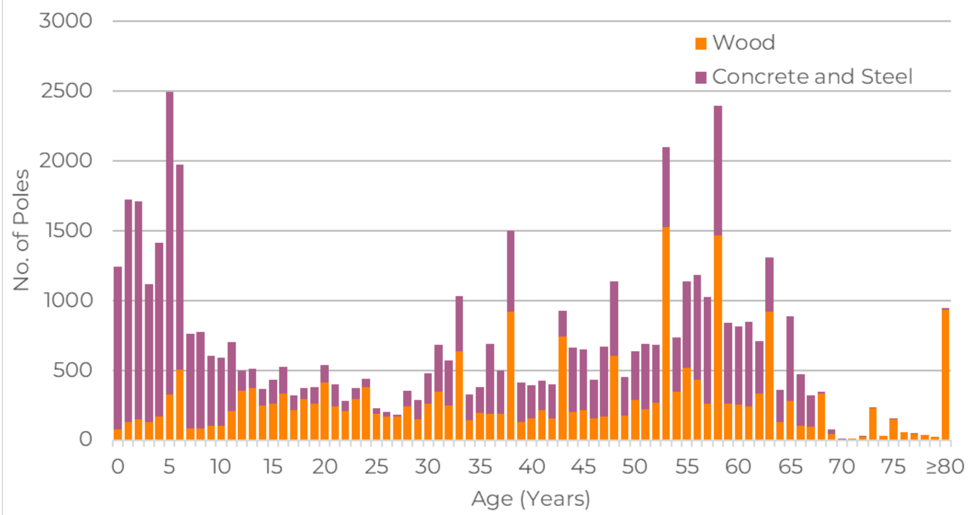
Table 11-9: Overview of poles by voltage

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
33 kV	2713	2107	781	5601
66 kV	0	1423	0	1423
HV	13993	13692	3091	30776
LV	12667	2410	763	15840
Total	**29,373**	**19,632**	**4,635**	**53,640**

ASSET AGE

Figure 11-7 below shows that a number of our hardwood poles have exceeded, or soon will exceed, their expected life of about 50 years.[9] In contrast, very few concrete and steel poles have yet 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



ASSET HEALTH

The condition of poles is determined by various inspection methods, such as visual, dig, 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 Auroa.

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 assists in prioritising pole replacements. Typically, poles with a higher criticality rating are replaced first.

As an additional control, we have implemented a sample programme of re-

[9] Estimated from our wood poles survivor curve, which is informed by historical data.

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 of assessing asset health. Previously, we estimated the health of poles primarily using age and expected survivorship. Age-based AHI models are often misleading, as asset operation and the effects of the environment can significantly impact the life of the asset. Consequently, we developed an AHI model which 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 have been identified to be 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.

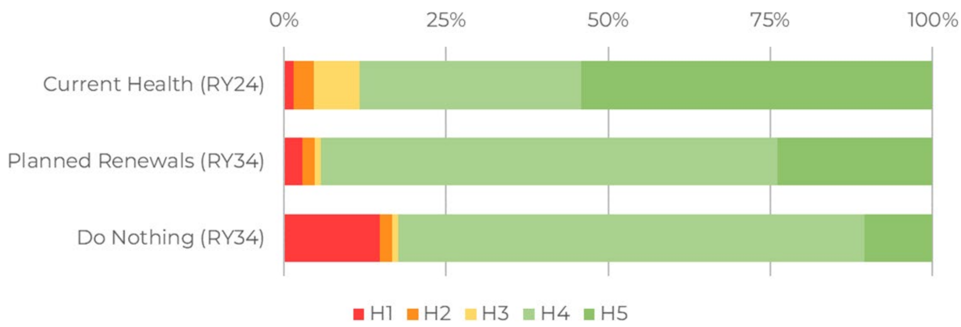
For poles with deterioration at the top, the condition AHI is set to H2 regardless of the pole's grade. This is because we expect the pole will soon not be able to support other assets. Once we have improved crossarm information, this criterion should be modified to only include poles with a poor head and a poor crossarm state.

We have modified the pole AHI model to better handle asset replacement that is undertaken as part of other projects. An additional input has been included to identify poles that will be replaced as part of another project if not determined to be prioritised by the AHI score. 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.

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 – i.e. we may prioritise a H2 pole located outside a school over a 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, once it's been 15 years since install the health is recategorised in the model to H1. We have 650 nailed poles coming to the 'end-of-life' at the end of the planning period.

Where we have deployed this life-extension strategy on a section of the network, line renewals will be considerate of the life extension recommendations.

It is also noted that the vast majority of the H1 shown in RY34, are earmarked for replacement in RY35 – the 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 works presents a significant workplace safety hazard.

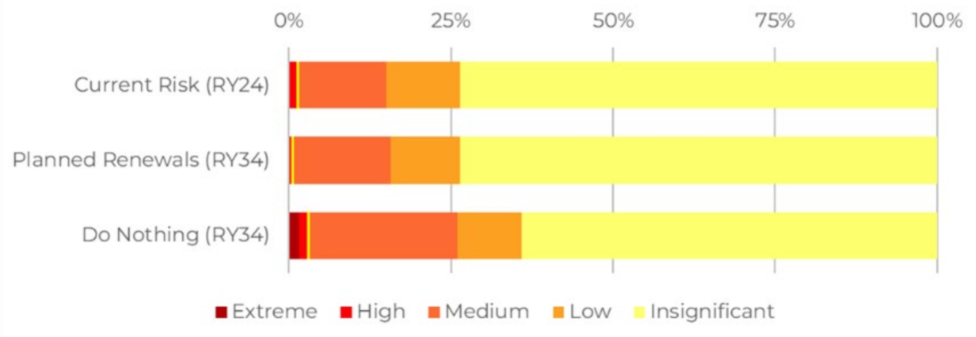
Table 11-10 sets out the failure modes, including systemic risks for this asset class, the risks posed by the failure mode, and how Aurora is managing the risk. Level of risk is assessed as a function of the asset health and the asset safety criticality. Assets in Criticality Zones 1-3 are prioritised 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, bring 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 F** Where poles fail the test criteria, options for replacement are considered. Typically, replacement with the current standard pole
Car v pole: Poles are commonly located adjacent to roads, bringing the risk of cars colliding with poles	Relocation of poles where possible/undergrounding
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 F** 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 F** 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 F** 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 F** 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 F** 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 F** Rectification is undertaken when required

The reduction in the number of poles categorised as *Intolerable* (those to the left of the vertical yellow 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 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 life of the pole 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 either the risk of failure is high and renewal is not practical at the time or it is known that more significant work (including relocation or decommissioning) is in the pipeline, rendering ad hoc renewal economically unviable. The processes applied when deciding when an asset should be replaced take into account condition and criticality (safety sensitivity and location). The drivers for replacement are typically:

- 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

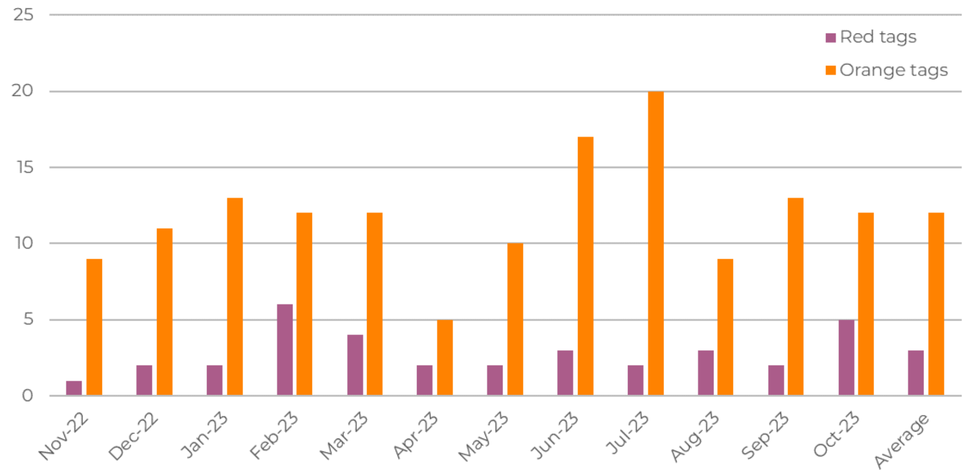
TAGGED POLES

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 tag poles to 19, representing a population of predominantly under control recently-found red-tag poles. Currently, we have no red-tagged poles that are outside of compliance, which means any new finds are being addressed within three months.

Our population of orange-tagged poles (not suitable to support design loadings such as high snow/ice event loadings) as of December 2022 was 674. As such, these poles remain a focus for rectification in RY23–RY24. As of November 23, there was a total of 472 orange tagged poles, of which 286 were in backlog – i.e. not addressed within 12 months. Rectification options for these poles 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 are discovering 12 new orange tag and 3 new red tag poles per month.

Figure 11-10: Newly discovered red and orange tags



WAIPORI LINES

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, a strategy of strengthening through nailing has been implemented, where 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 RY25. 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 $107m during the 10-year planning period, which is significantly more than forecast during our previous AMP. This change is informed by improving risk forecasting capability, and improved condition assessment techniques. The additional expenditure also encompasses the cost of 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 is reduced from RY25, there are a number of contributing factors, including:

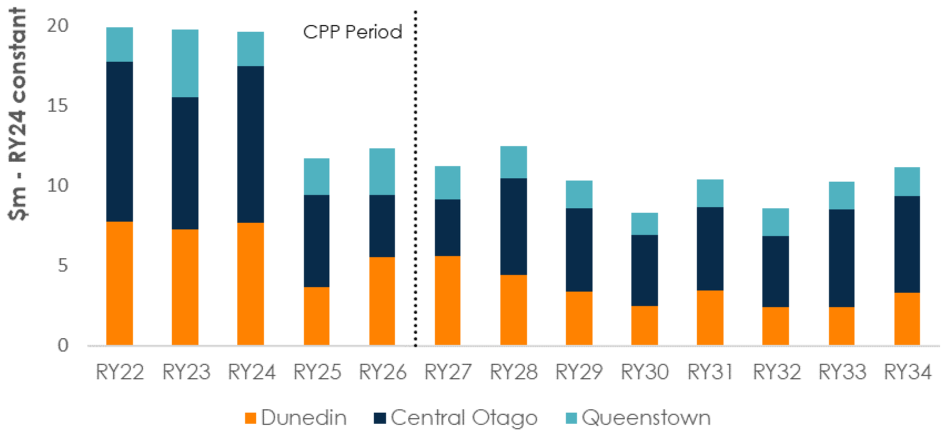
- A maturing view of asset condition and failure modes which has enabled us to re-assess risk and intervention thresholds – e.g. leaning poles
- Progress against SDP commitments for this fleet
- Increasing pressure to financially facilitate growth on our network
- Significant conductor renewal projects, such as the Waipori A, B and C lines, where the end-of-life poles will be replaced as part of the conductor renewal projects – i.e. associated assets

Specific programmes and expenditure are shown in Table 11-11 and Figure 11-11. Note that the 500 poles called out in the Waipori A, B and C lines project, constitutes poles that are 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	RY25–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 (RY24 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. Our crossarm fleet consists of a variety of different types and configurations due to different equipment suppliers, historical line designs, line voltage levels and historical network owners.

We have approximately 90,480 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, though a limited number of galvanised steel crossarms are also used.

Table 11-12: Crossarm population

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Crossarm	56352	31534	7830	95716
Total				**95,716**

ASSET AGE

Our historical data sets do not have age entries for crossarms. In all cases where a pole is replaced, new crossarms are installed. Given that there has been no historical crossarm replacement programme, 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. The average age of our crossarms is shown in Table 11-13 for each sub-network.

Table 11-13: 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 historic pole inspections, it is not fit for purpose, from the perspectives of both data quality and completeness. The data gathered from historic pole inspections indicated that the crossarm fleet health was poor. In response, and knowing some limitations existed in that data, we undertook some structural testing of decommissioned crossarms. The testing outcomes confirmed shortcomings in the crossarm condition data gathered under the first pole inspection programme.

Since standing up the new improved OH Inspection programme, we have gained access to quality data, which further supports these limitations. Once the first round of the new improved inspection programme is complete, we will have a more advanced understanding of the overall condition and health of this fleet.

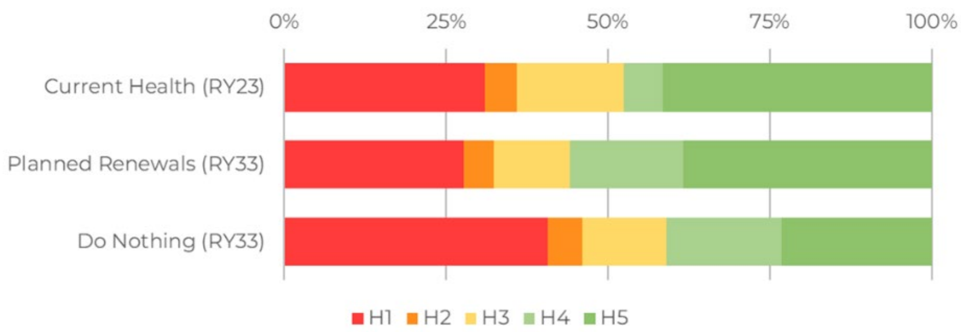
We expect the enhanced inspection regime to significantly improve the known health/ condition profile of the crossarm fleet through:

- 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 lesser focus on visual appearance (ageing, moss) of crossarms used in the previous assessment regime
- Capturing accurate position info of each inspection crossarm (facilitating targeted replacements)
- Shifting to inspecting all crossarms (vs the 2017–2023 policy of inspecting crossarms greater than 10 years old), allowing identification of early onset failure and construction defects.

It will take a full 5-year inspection cycle to gain the full benefit and insights of the updated inspection criteria.

Aurora Energy's current crossarm health profile and forecast change uses an age-based approach. The crossarms are assumed to have the same age of the associated pole and an expected life of 55 years and 75 years for wooden and steel crossarms, respectively. The output is summarised in Figure 11-12. There is a reduced rate of replacement for the coming two years while we focus on gathering the enhanced condition data.

Figure 11-12: Projected crossarm asset health



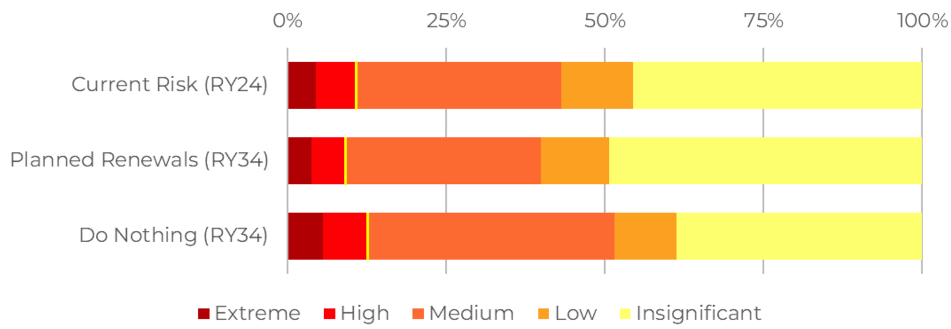
ASSET PERFORMANCE AND RISK

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 the initiation of a Root Cause Analysis (RCA) of asset failures in 2023 we have established a robust basis to collect data on the number and type of crossarm failures, so we can 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-based 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-based 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-based 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-based and aerial-based inspection programmes, leading to replacement of visually defective crossarms
Conductor down or conductor floating event - Binder failure	Ground-based and aerial-based inspection programmes, leading to corrective maintenance defect repairs
Bird strike (particularly NZ native falcon) on steel crossarms - Pole located in falcon sighting/breeding area	Falcon guard retrofit programme on steel crossarms near falcon sighting/breeding areas
Loss of secure connection between the crossarm and the pole and/or the 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 we have undertaken industry research and subsequently amended our design standards, we also implemented a Corrective Maintenance activity and are actively inspecting security of bolts and nuts under the PM OH Inspection programme

Figure 11-13: Projected crossarm risk



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 identified asset for replacement.

A priority is placed on crossarms with imminent insulator defects (leaning/cracking) and located within high fire risk zones.

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 replacements.

DISPOSAL

When crossarms are removed, efforts are made to donate or repurpose them for landscaping or agricultural uses. In cases where repurposing is not feasible, landfill disposal becomes necessary due to concerns related to the treatment 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 treatment preservative.

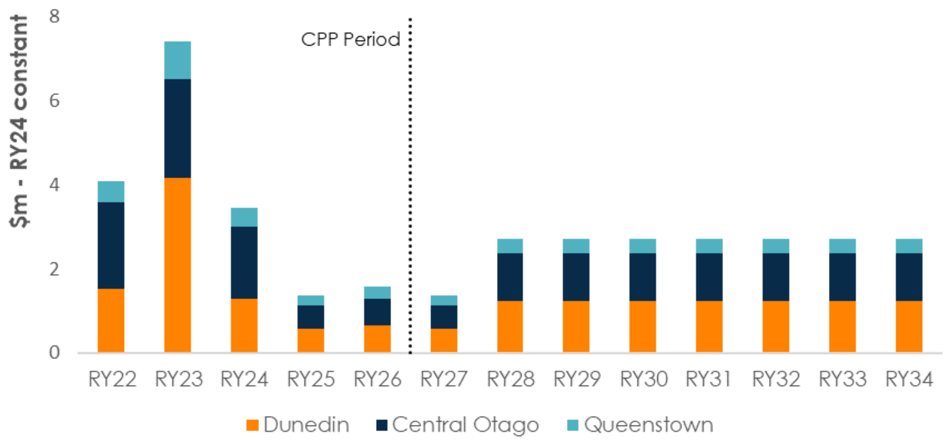
FORECAST CAPEX EXPENDITURE

Our expenditure plan has changed considerably since AMP23. There are a number of factors behind the drop in renewal planning including:

- The limitations in the condition data, retrieved 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 see the new and enhanced OH Inspection information coming in
- The need to create financial capacity to facilitate growth
- The plan below does not capture crossarms replaced when the pole is replaced – i.e. associated assets

Figure 11-14 shows the predicted Capex expenditure on crossarms for the forecast period.

Figure 11-14: Capex forecast crossarms by region (RY24 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.

Overhead conductor, along with support structures and the plant and equipment on them, all comprise a system that make our overhead line network, which comprises approximately 63% of our total network circuit length.

The allocation of overhead conductor into respective sub-fleets reflects not only the risks and criticality associated with the assets, both of which vary with voltage, but also the inherent nature of each voltage level. Different combinations of these factors lead to different lifecycle strategies.

Our conductors are installed in a range of different environments from inland alpine to coastal, and a range of different contexts from agricultural to industrial, giving rise to different degradation mechanisms and subsequent lifecycle management.

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 different material types across the three conductor fleets and three sub-networks.

- **ACSR:** Aluminium conductor steel reinforced
- **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	266.3	0.01
	AL	12.1	75.2	232.1
	CU	105.4	381.6	569.3
	ST	0	4	0.07
	Unknown	0	2.3	6.9
Central Otago & Wānaka	ACSR	293.7	1,007.3	10.6
	AL	2.7	84.3	59
	CU	11.9	25.4	38.7
	ST	0	150.5	0.03
	Unknown	0	2.7	65.9
Queenstown	ACSR	67.2	250.5	1.4
	AL	2.0	11.7	14.2
	CU	0.2	6.3	5.8
	ST	0.0	13.1	0.0
	Unknown	0.0	0.4	23.1
Network total		**520.7**	**2281.7**	**1027.1**

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 through either overload in operational management due to applying 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, Overhead Inspection will require inspectors to validate conductor type records as part of inspections. 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 minimise the risks.

We also expect that the implementation of Gridsight would 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 to track and update all validated data.

ASSET AGE

Our oldest conductor was installed in 1907 and our newest in 2023. Figure 11-16 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 as AHI model. However, there is some risk in this approach because our conductor age data is incomplete and often incorrect in our records. 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 11-15 and Figure 11-16 show our conductor age profiles by operating voltage and conductor material.

Figure 11-15: Conductor age profile by operating voltage

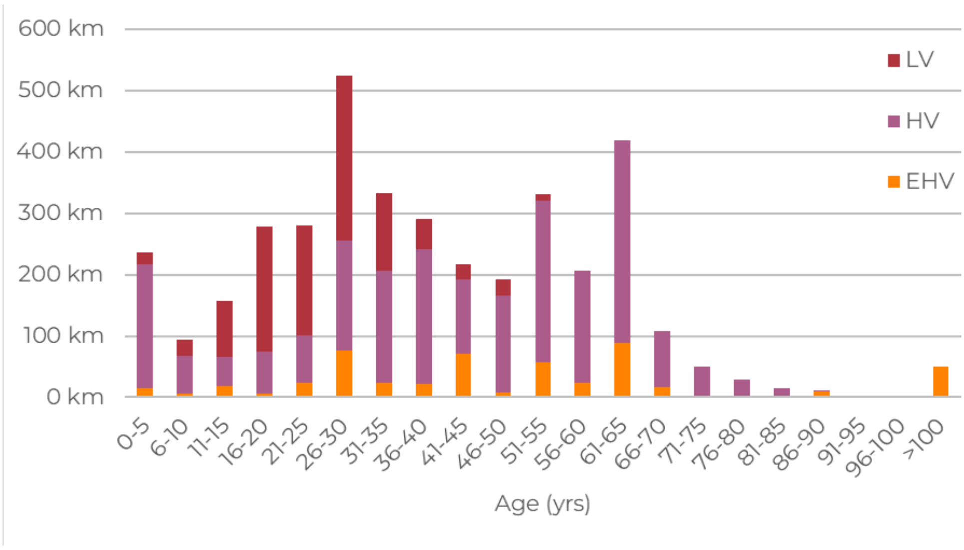
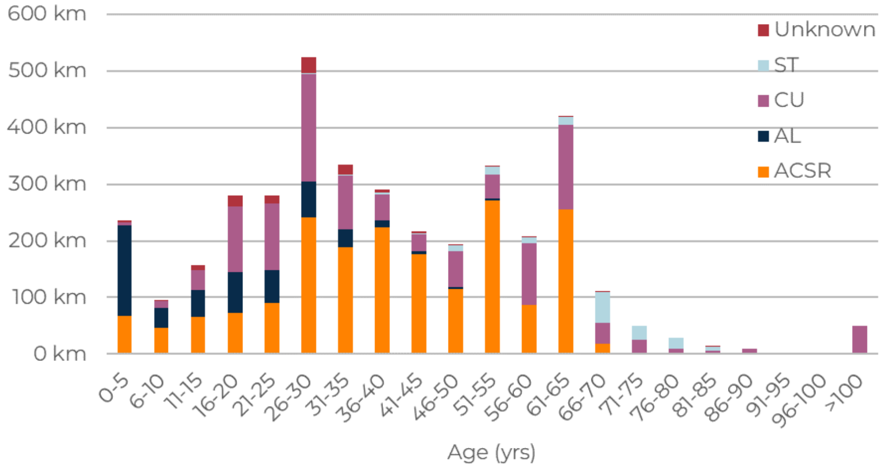


Figure 11-16: Conductor age profile by conductor material



ASSET HEALTH

Overhead conductor condition assessment typically represents 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. Aurora Energy now requires inspectors to grade conductor condition using a visual representation guide as part of cyclic overhead inspection, with the data fed into the asset health model. The visual grading criteria is aligned to the EEA asset health indicator scale.

We use material, size, age and location data as the primary driver 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 expected lives we have set out provide a good starting point and are within the bounds of good practice when compared to the life expectancies used by other NZ electrical asset owners, 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	< 100	48	59	75
Unknown		52	62	88

Our AHI model uses the material, size, age, location and visual grading from inspections to determine conductor life expectancies. Figure 11-17 to Figure 11-19 below compare the current health of the asset fleet to the projected asset health in RY34 following our planned programme of renewals, and a counterfactual 'do nothing' scenario. This comparison indicates the benefits provided by our proposed expenditure programme.

Figure 11-17: Projected EHV conductor asset health

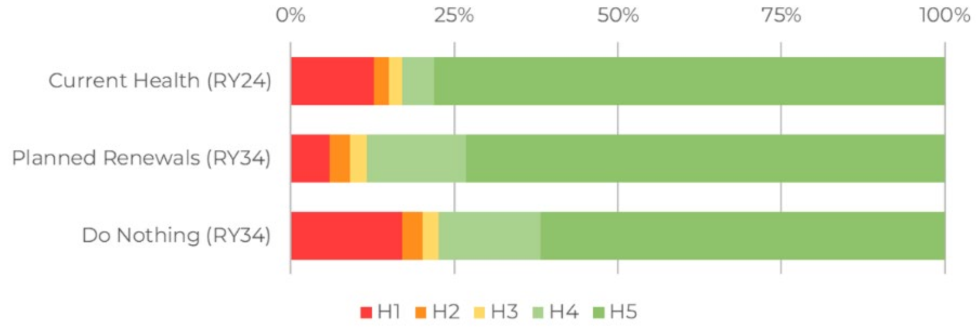


Figure 11-18: Projected HV conductor asset health

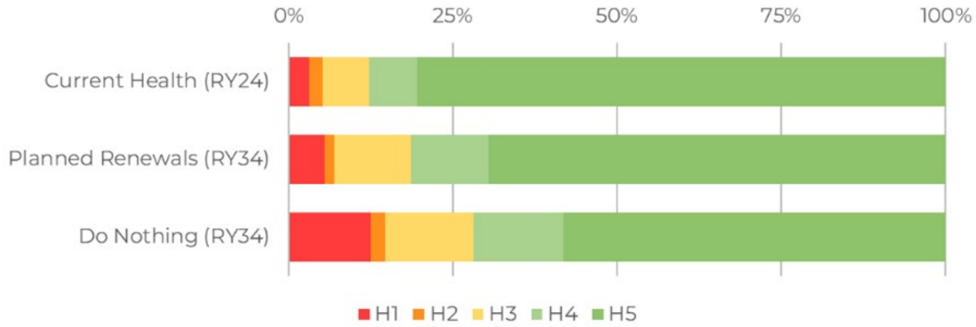
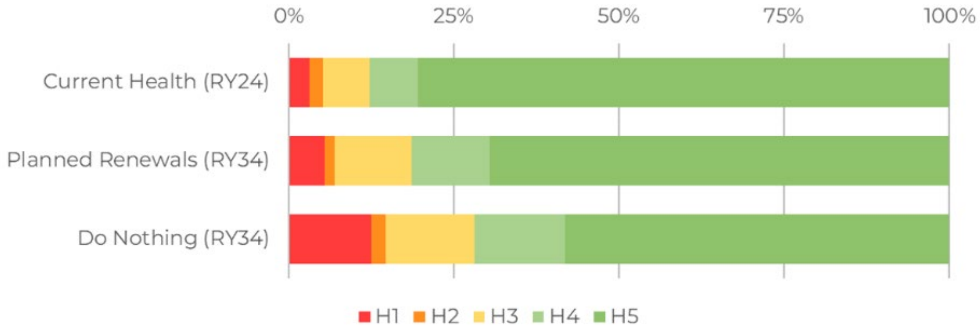


Figure 11-19: Projected LV conductor asset health



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/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 joints/fittings usage and installation Protection systems and prioritised electromechanical relay replacement programme RCA on failures, targeted advanced inspections in response to monitored reliability and performance, including on associated assets that may lead to conductor failure to ground incidents
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 Vibration damper install 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/maintenance for all subtransmission plus those identified as critical distribution feeders Fitting of bird diverters and/or falcon guards onto steel crossarms in areas of known significant presence/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 and 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, it is assessed that 7/.067 Copper, 4SWG Copper, and No. 8 Steel conductors are identified as being at greatest risk of unassisted failures.

7/.064 Copper has been targeted due to being an aged, small diameter low strength conductor which has had multiple unassisted failures across the network (five in 2023), with investigations determining the failure mode to be corrosion fatigue. On the HV network we have approximately 160 kilometres of 7/.064 Copper or 7% of HV conductor. Testing has indicated an average degradation of 26% from new ultimate tensile strength.

4SWG Copper has been targeted due to being the oldest conductor on the network. Installed in 1907, the conductor is now obsolete making 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.

Under binder fretting has been identified by some contractors on aged copper conductors when carrying out maintenance activities on the associated pole, it has also been identified on returned conductors from renewal projects. It is planned to raise awareness of this failure mode/degradation with contracting staff and request intrusive inspections as part of planned work in 2024 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 improvements in 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. The 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. Full tension joints on the conductor were often made by wrapping the conductor back on itself resulting in a high resistance connection adding to the issues.

This conductor will often elongate following bird or tree strikes or after a snow event leading to a subsequent failure. Due to the fact that the conductor was manufactured as fencing wire and not to conductor standards, a known new material strength is not defined, as the new steel grade is unknown. This makes destructive testing type degradation assessments impractical.

On the HV network we have approximately 145 kilometres of No. 8 Steel conductor – or 6% of HV conductor. There was one unassisted failure in 2023, with investigation determining a failure mode as corrosion fatigue.

Failure of OH conductor can also be caused by factors unrelated to the conductor's condition. Vegetation or trees that strike or fall through the lines is one of the most common causes of conductor failure. Third-party strikes – from agricultural or construction plant, are also common causes of conductor failure.

With the new RCA process in place, we are establishing a more robust process to ensure the correct cause is established – hence enabling us to trend cause rather than just number of failures, enabling us to respond effectively to 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.

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.

With the new Overhead Inspection programme rolled out in 2023, we are actively gathering more data to enable enhanced predictive analysis and forecasting. We are also actively maturing our understanding of asset performance through implementation of RCA on all failures.

We will review and update our forecasts as the benefits of the new OH Inspection programme are realised.

Our current programme is informed by/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 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 region. The Dunedin renewal Waipori ABC lines, as discussed above, is 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 zones.

LV DISTRIBUTION

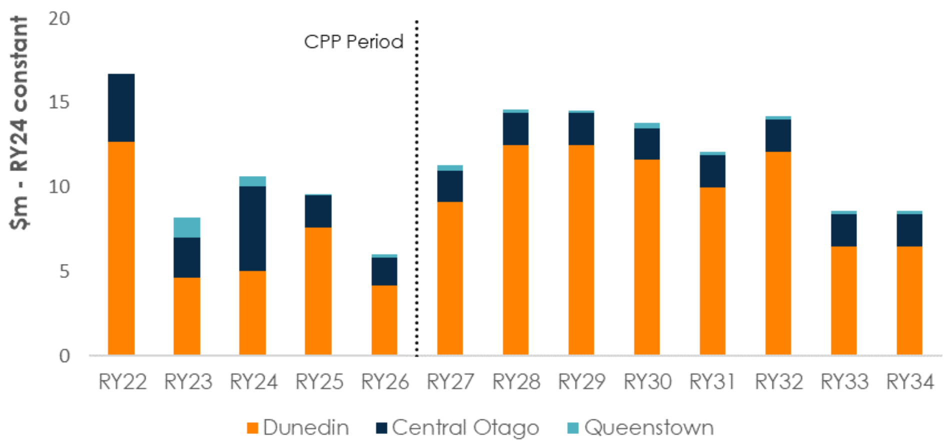
Of our distribution LV conductor, approximately 21% is nearing the same replacement criteria. We are targeting small diameter low strength LV conductor such as 7/.064 and 19/.052 Copper for renewal. To realise cost and interruption efficiencies, we are prioritising conductors that are showing signs of 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 sufficiently degraded that 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 11-20: Capex forecast overhead conductor by region (RY24 constant, $,000s)



Our forecasts for Subtransmission Conductor have changed from AMP23 to AMP24 – increased by $11.63m in the period of RY26-RY30.

Key considerations in making these adjustments are:

- Increase in cost of major subtransmission renewal projects
- Increasing capacity/voltage requirements on subtransmission lines – larger conductor required for new lines
- Timing supported by learnings from RCA

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 increasing focus/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 by conveying electricity between the transmission system, zone and distribution substations, and LV customers. They come in a variety of types and sizes, enabling electrical flow at various voltages. This portfolio also includes 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 the 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 the 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	18.0	272.3	34.7
	XLPE	39.3	59.5	192.0
	PVC	0.0	0.0	53.0
Central Otago & Wānaka	Gas-filled	0.0	0.0	0.0
	Oil-filled	0.0	0.0	0.0
	PILC	0.1	58.3	1.4
	XLPE	16.1	516.6	475.4
	PVC	0.0	0.0	28.5
Queenstown	Gas-filled	0.0	0.0	0.0
	Oil-filled	0.0	0.0	0.0
	PILC	0.0	81.1	2.1
	XLPE	40.1	210.0	278.2
	PVC	0.0	0.0	31.1
Network total		156.3	1197.8	1096.4

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 required additional assets to maintain and monitor the gas pressure, there is a risk of gas leaks that can degrade insulation levels, and it 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 required 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 it 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 11-21 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 11-21: Subtransmission cable age profile

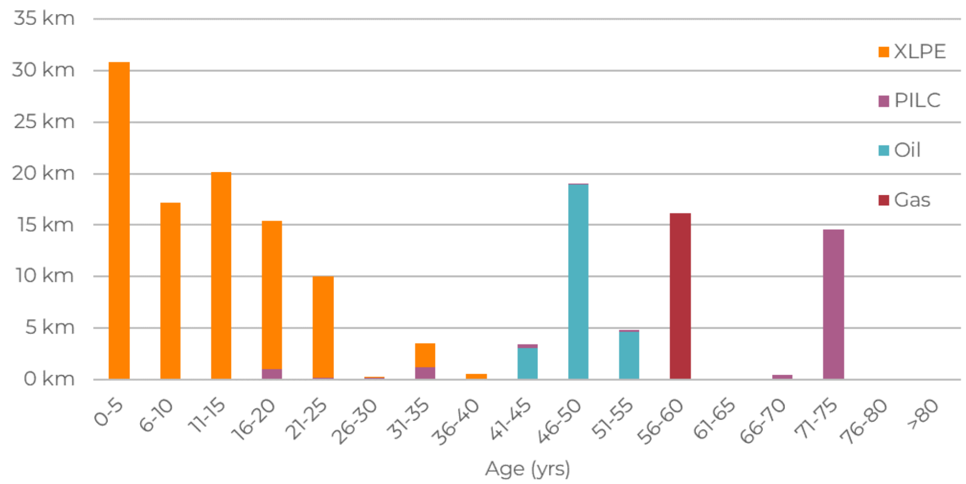


Figure 11-22 shows our distribution cable age profile. Our distribution cable fleet is considerably younger than our subtransmission cable. The young population of XLPE distribution cable reflects the large growth in new connections in the Central Otago & Wānaka and Queenstown regions over the last 20 years.

Figure 11-22: Distribution cable age profile

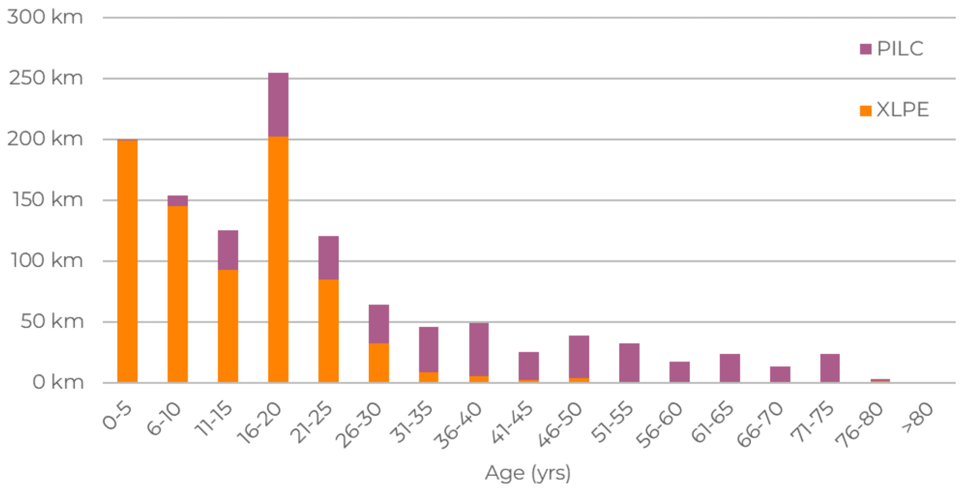
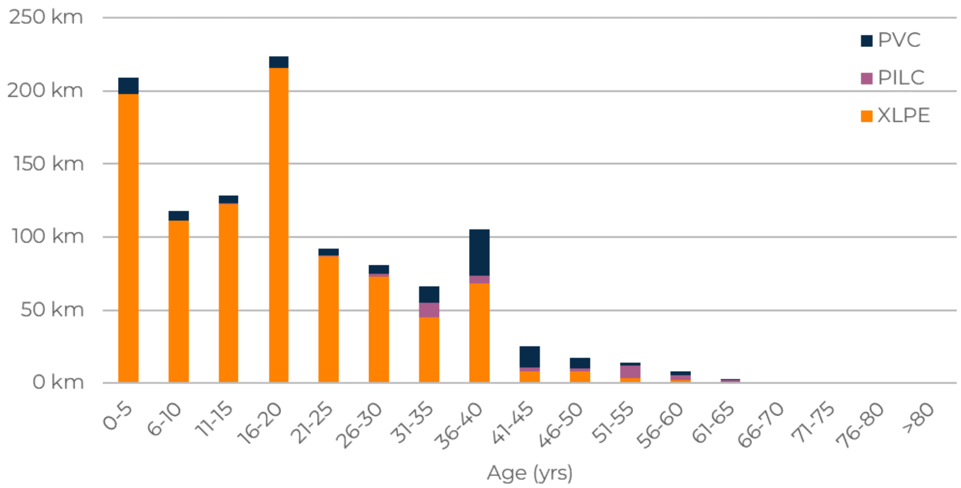


Figure 11-23 depicts our LV cable age profile. Our LV cable fleet is relatively young, much of it reflecting network growth over the past 20 years.

Figure 11-23: 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 the cable portfolio is informed by condition and non-condition parameters, age, and criticality. Figure 11-24 to Figure 11-26 show the AHI of our cables by fleet. The condition factors are prominent where we have known failure or fault occurrences, and known issues with the original design other than for those cables (all subtransmission cables identified for replacement in the AMP period), we are reliant on age-based health models for forecasting. The model for subtransmission cables is showing that when the three identified priority projects have been completed, the overall health profile is improved, while of course some age-based deterioration is inferred.

As discussed in **Renewal priorities**, below, for distribution and LV cables, renewals are mostly reactive. This is aligned with our commitment to invest in Safety First. Also, there is a lesser reliability impact and as a result, investing in this fleet has not yet been a priority.

Figure 11-24: Projected subtransmission cable asset health

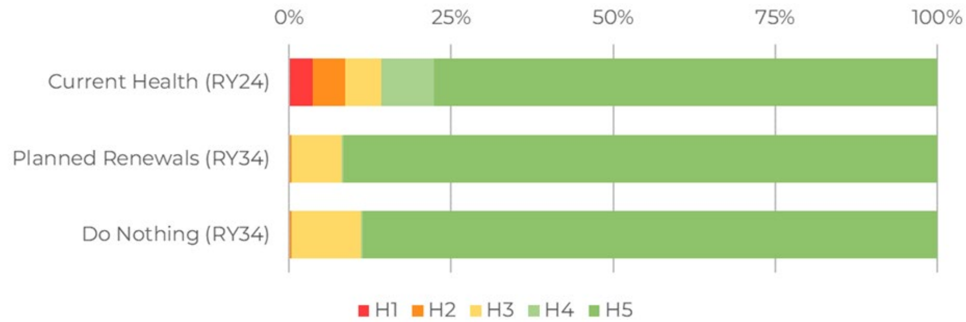


Figure 11-25: Projected distribution cable asset health

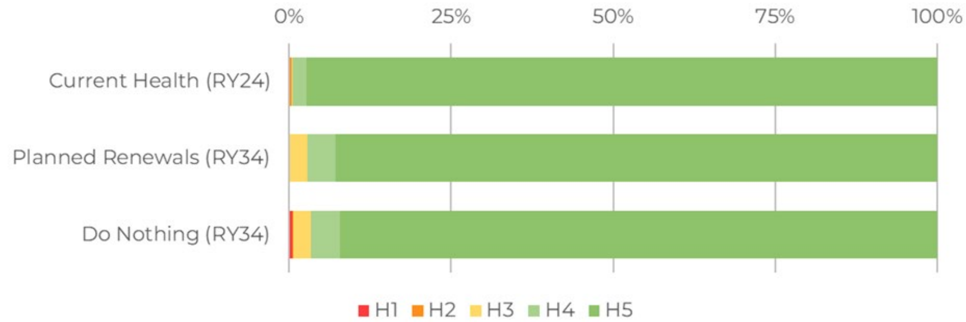
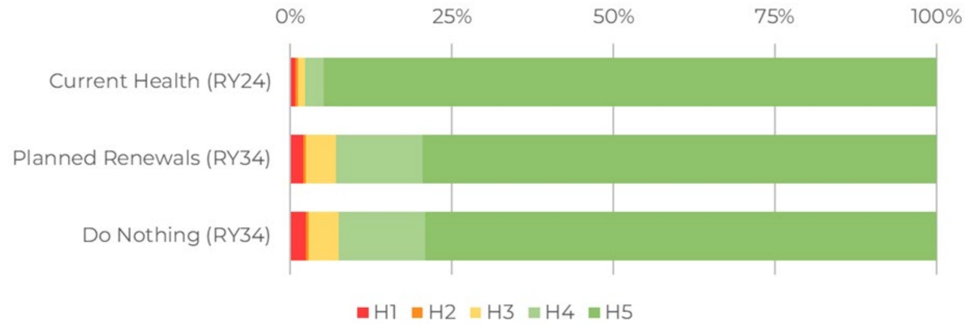


Figure 11-26: Projected low voltage cable asset health



ASSET PERFORMANCE AND RISK

Asset performance and risk apply generally across all of our underground cable fleets, so 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	B4UDIG 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 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

Significant cable failures are now investigated with findings recorded in a consistent way and unassisted failures with a root cause condition driver are reviewed against our conductor health model to ensure data accuracy.

REPLACEMENT/RENEWAL

At present, we identify renewal candidates by using age and expected life as a proxy for condition, and augment this using condition information where available. As previously mentioned, we validate data and use inspections and testing of samples of conductor to continually adjust or validate remaining functional life expectancies.

Where cables are identified with 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 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, 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 removed by RY44 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. Due to the nature of replacing subtransmission assets in a built-up environment, the plan is to replace our oil and gas cables by RY44 (a 20-year horizon). Where cables cannot be replaced in the existing route an alternative route will be identified – or 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 to have 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 is considerate of renewals, 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/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. Since we were alerted to 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 prioritised the removal of units in high criticality locations, such as near schools or high population density areas. Work undertaken on assets with a direct impact upon cast iron cable terminations will automatically trigger the removal of these items.

The replacement of CIPH is often not straightforward and often 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. Efficiencies are always being explored for consolidated work packages that bundle drivers of many projects by outage zones to minimise the cost and reduce customer impact due to the required outage to replace CIPHs.

To date, 280 units have been replaced or removed and the remaining 100 (this number includes new discoveries) will be removed by RY26.

DISPOSAL

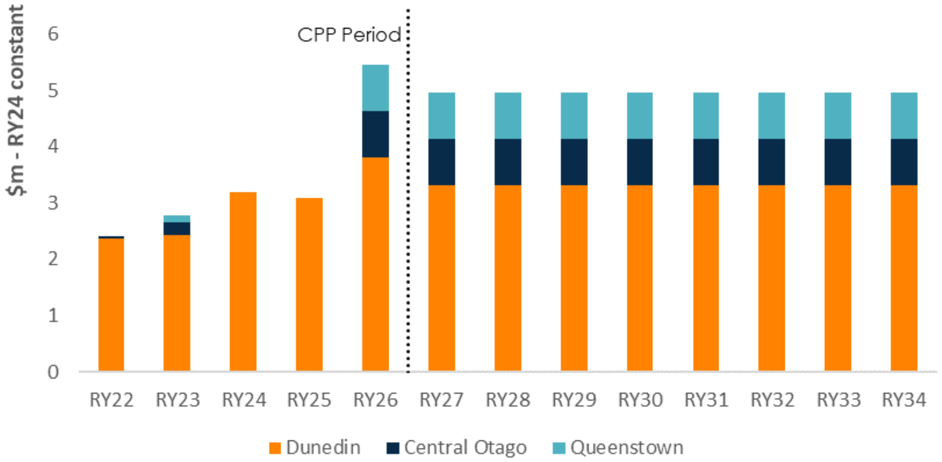
Generally, when a cable is abandoned, only the above ground sections are recovered, while the below ground sections are made safe at the point of being severed where they enter the ground by fitting a cap and burying the cable tail.

Where the cable is an oil or gas-filled cable the oil or gas is extracted from the cable and the oil or gas either recycled or disposed of.

Recovered cable is then collected by third-party scrap dealers for processing.

FORECAST CAPEX EXPENDITURE

Figure 11-27: Capex forecast underground cables by region (RY24 constant, $m)



Our forecasts for subtransmission cables have changed from AMP23 to AMP24 – increased by $10.21 in the period of RY26–RY30.

Key considerations in making these adjustments are:

- Health forecast updated to reflect emerging trend of failures and we have changed 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
- Maturing view on project scope and costs – feasibility studies undertaken/underway. We will be focusing on extending our Major Projects, Cost Estimation process to incorporate subtransmission cables, and expect that once feasibility studies and route options are fully explored, we will need to flex our plan
- Increase in cost of 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 increasing focus/resources.

11.6. ZONE SUBSTATIONS

This section describes our zone substation portfolio, which comprises the following five asset fleets:

- Buildings and grounds
- Power transformers
- Indoor switchgear
- Outdoor switchgear
- Ancillary equipment

Zone substations take supply from GXPs through 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 11-28 shows one of our modern zone substations.

Figure 11-28: Andersons Bay zone substation

We also own and operate a mobile zone substation, which reduces or eliminates the need for lengthy planned outages. It 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 36 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 have fencing and earthing. 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	4
Total	**36**

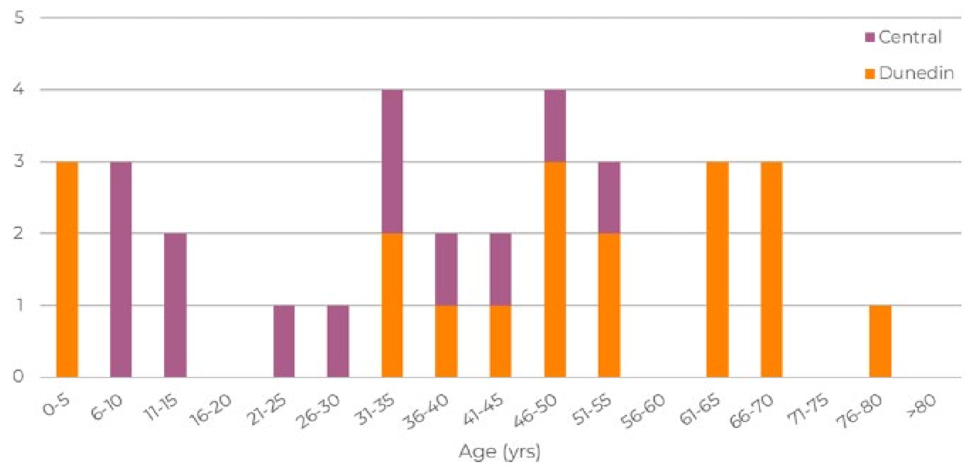
Our zone substation buildings mainly house protection and communications equipment, indoor switchgear, and ripple injection plants. Buildings and grounds must provide security for the equipment contained within, be well secured against seismic risk, and be adequately earthed.

We have undertaken a seismic survey of our zone substation buildings, which identified a list of buildings that require strengthening to meet the NZ Building Code. We are presently addressing the issues identified.

ASSET AGE

The buildings in the fleet range from new to over 70 years old. A significant number of them were built between 1950 and 1970. Figure 11-29 depicts the age profile of our zone substation buildings by region.

Figure 11-29: Zone substation buildings age profile (by region)



The average age of our zone substation buildings is 38 years, with the buildings in the Dunedin region having a higher average age (49 years) than those in our Central region (24 years). The oldest substation building, located at Ward Street substation in Dunedin, is 77 years old and the newest substation building, located at Andersons Bay substation in Dunedin, was built in 2023.

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 fleet, but we will consider whether there would be value in developing such tools in 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.

We will continue to refine our methods of assessing building and grounds condition and consider whether there would be value in developing an AHI and criticality framework for this fleet in the future.

ASSET PERFORMANCE AND RISK

Table 11-21 summarises the key risks identified in relation to our buildings and grounds fleet.

Table 11-21: Key zone substation buildings and grounds risks and mitigations

Risk/Issue	Mitigation
Seismic event	Programme of structurally strengthening buildings to 100% of NBS for the IL3 standard and upgrading internal/external equipment hold-downs
Flooding event	Elevating equipment as it is renewed, above certain flood criteria, 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

Risk/Issue	Mitigation
Poor internal building environment leads to primary asset or electronics failure	Heat pump and insulation retrofits where practical Internal equipment anti-condensation heaters Replacement 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

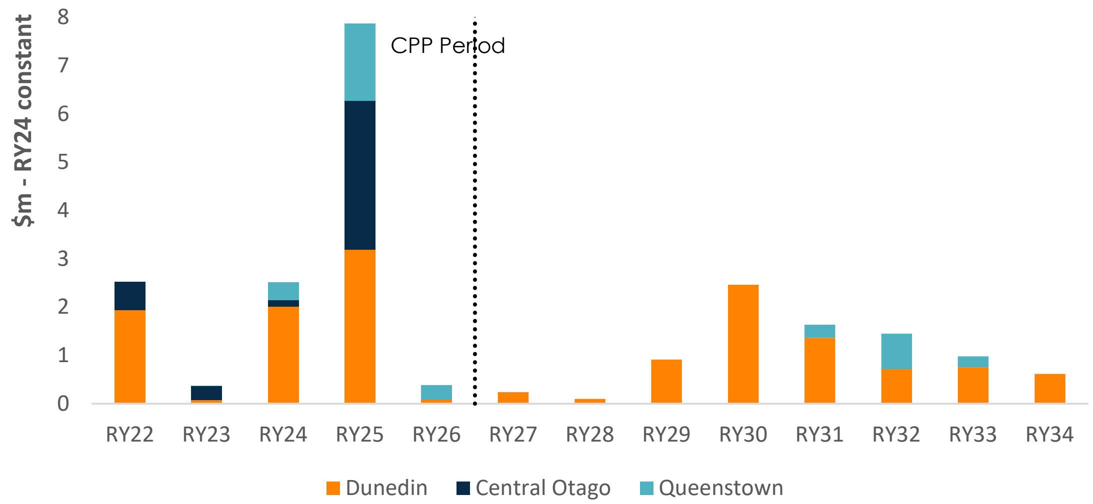
The renewal of buildings is often undertaken as part of an indoor switchgear renewal project and is driven by need for seismic upgrades and/or physical space to accommodate new equipment. We also consider the risks, future proofing requirements and costs associated with re-using existing buildings or land to accommodate new equipment.

DISPOSAL

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. Recently, we initiated a project to re-purpose the old Andersons Bay substation building for use as a MENZSHED facility.

FORECAST EXPENDITURE

Figure 11-30: Capex forecast buildings and grounds by sub-network (RY24 constant, $m)



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 70 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.

Figure 11-31: Power transformer

Table 11-22 summarises the population of our power transformer fleet by operating voltage and size.

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 of tap-changers, which have more maintenance requirements.

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	5	9
		VACUTAP	2	2	0
	>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	22	14

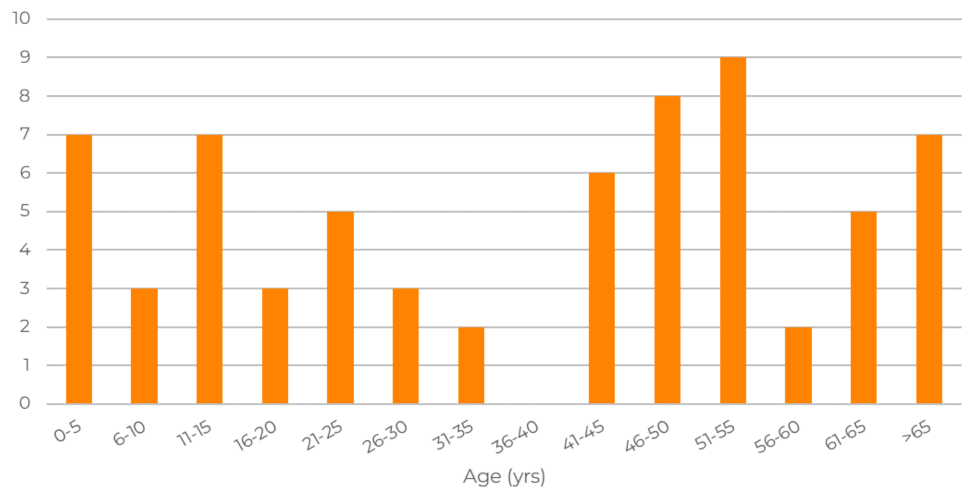
ASSET AGE

The transformers in the fleet range from new to 68 years old, as indicated by the age profile shown in Figure 11-32.

Recent renewals have reduced the average age of our power transformers 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 11-32: Power transformer age profile



ASSET HEALTH

Our routine testing and inspection programmes help us understand how our power transformers are ageing, and to 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 the measured condition parameters. The parameters measured are:

Oil analysis provides indirect evidence of the internal condition of the transformers including when there has been overheating, arcing and deterioration of the internal paper insulation. 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. Our fleet shows no major signs of these modes of deterioration, although we have three transformers with DP values of less than 500, indicating they are approaching the end of their serviceable life. Periodic use of online oil filtration has helped control moisture levels in our transformer fleet which reduces the rate of internal deterioration.

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.

The number of tap-changer operations. Each tap-changer is designed with a lifespan generally based on number of operations which determine when components such as contacts need to be replaced as well as when the tap-changer needs to be refurbished.

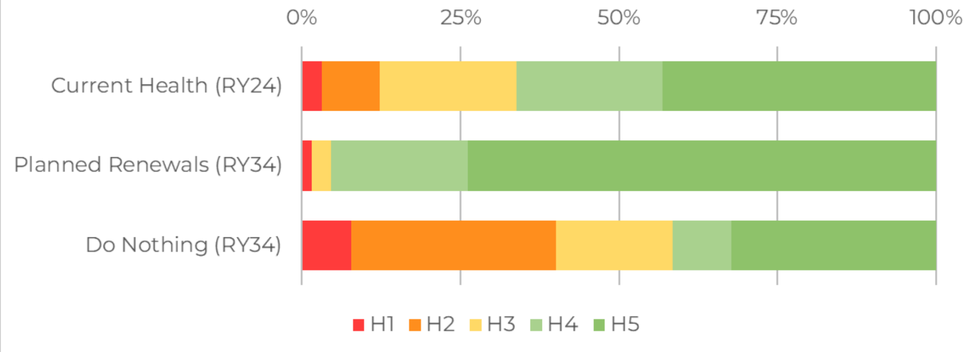
We determine the AHI of power transformers using a weighted average of scores derived from the condition measurements described above. As **Figure 11-33** indicates, our health forecast shows a reduction in H1, H2 and H3 transformers over the planning period due to the asset renewal plan. As we mature our understanding and management of asset risk, we will continue to refine our methods of assessing asset health.

We aim to further develop the framework to incorporate other condition EOL drivers such as visual inspections of the main tank, radiators and 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 (competence, spares, etc.).

The external condition of the fleet is assessed through visual inspection and includes 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 are an imminent failure concern or 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 35% (H1–H3) will be considered for replacement in the planning period.

Figure 11-33: Projected power transformer asset health



ASSET PERFORMANCE AND RISK

Power transformers are high value and 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, they are carefully monitored and managed.

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, and on-load tap-changer (OLTC) failures 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 of the failed transformers is 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 power transformer risks 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 which 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 consequence of an oil fire
Seismic event	New transformer arrangements are seismically compliant and do not have mercury switches on protective devices 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 Keep unit spare parts once decommissioned, in case of future failures Preventive and corrective maintenance of OLTCs
Lightning strike or switching surge	HV and LV surge arresters on new transformers as standard practice Retrofit surge arresters onto existing transformers where feasible

Risk/Issue	Mitigation
Excessive transformer noise	Investigate complaints and remediate to council limits if required Acoustic studies and transformer specification Fit vibration pads under new transformers and consider retrofit on a case-by-case basis Consideration to move to ODAN transformers to avoid issues with noisy fans

Over the last 15 years, we have had five major power transformer failures at our substations that led to full replacement of the transformer, as follows:

- 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.

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 two 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 and a distribution backfeed scenario where the affected feeders are supplied through 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 the 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 should a catastrophic failure occur.

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.

The risk profile of transformers is forecast, and intervention is planned to occur 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 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) 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 if it is no longer required or the customers can be supplied from an alternative zone substation

When assessing the need to replace 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

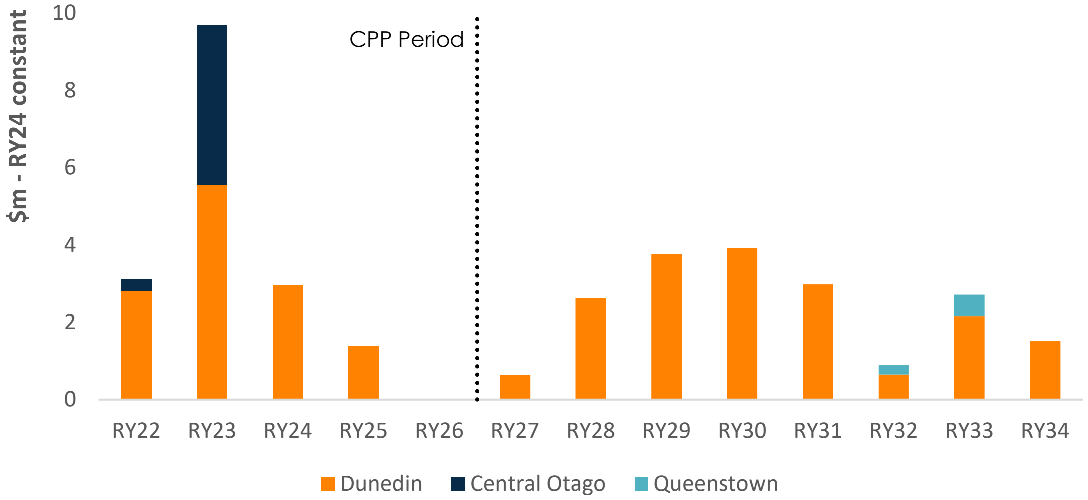
We renew power transformers based on risk, as informed by asset health and criticality. Our risk framework generates an 'AHI vs Criticality' Risk Matrix for all power transformers for the planning period. Those transformers whose 'AHI vs Criticality' show the highest likelihood and highest consequence are considered to present an intolerable risk and need to be addressed/replaced. Refurbishment of assets is currently considered on a case-by-case basis but generally limited to bushings, tap-changers and oil replacement/filtration. We have recently initiated an enhanced condition assessment programme for H1 and H2 power transformers. This work will provide greater certainty of our assessed health and subsequent assessment of remaining life on an asset-by-asset basis and ensure that 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.

FORECAST EXPENDITURE

Figure 11-34: Capex forecast power transformers by region (RY24 constant, $m)



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 11-35 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 insulation and metering equipment. They may also contain protection and control devices; alternatively, they may be installed in a separate relay panel, sometimes located in a separate protection/control room.

Figure 11-35: Indoor switchboard at Andersons Bay

Our indoor switchgear fleet contains a total of 344 indoor circuit breakers (making up 30 switchboards). Table 11-24 summarises the population by type, rated voltage and sub-network.

Table 11-24: Indoor switchgear population by insulation medium and operating voltage

Interrupting Medium	Voltage	Dunedin	Central Otago & Wānaka	Queenstown	Total
Oil	11 kV	161	8	0	169
	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	70	42	34	146
	33 kV	0	0	0	0
	66 kV	0	0	0	0
Total		**247**	**50**	**47**	**344**

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 can be used to isolate equipment but cannot be used to break significant load current. Load break switches connect, disconnect and isolate and can be used to break load current.

Our outdoor switchgear fleet contains a total of 374 outdoor switchgear units, comprising circuit breakers, reclosers (within zone substations, reclosers provide zone substation circuit breaker functionality), and switches. Table 11-25 summarises their populations by type.

Table 11-25: Outdoor switchgear population by type/insulation medium and operating voltage

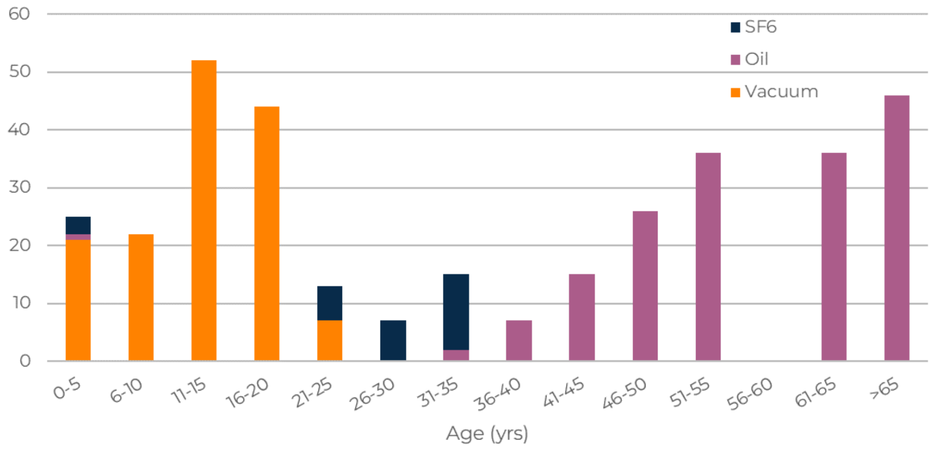
Interrupting Medium	Voltage	Dunedin	Central Otago & Wānaka	Queenstown	Total
Oil	11 kV	0	3	2	5
	33 kV	4	8	1	13
	66 kV	0	1	0	1
SF_6	11 kV	0	0	0	0
	33 kV	0	0	0	0
	66 kV	0	14	0	14
Vacuum/Reclosers	11 kV	1	11	8	20
	33 kV	15	17	11	43
	66 kV	0	0	0	0
Air break switches		147	102	29	278
Total		**167**	**156**	**51**	**374**

ASSET AGE

The technology associated with switchgear has evolved over time. The majority installed prior to the 1990s used oil as the insulation medium, and these make up a significant proportion of our current population. The remainder (generally installed after 1990) are vacuum or SF_6-insulated.

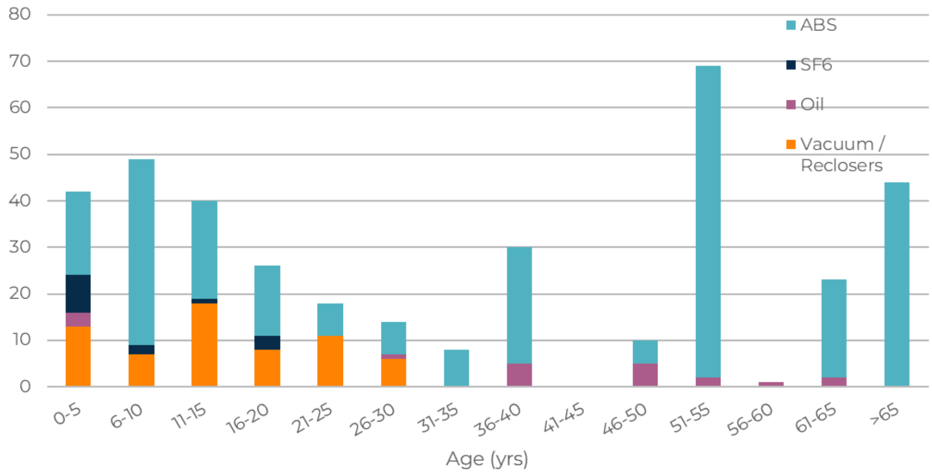
The average age of our indoor circuit breakers is 35 years, with those in our Dunedin sub-network region having a higher average age than those in our Central Otago & Wānaka and Queenstown sub-network regions. Figure 11-36 shows the age profile of our indoor switchgear by circuit breaker type.

Figure 11-36: 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 11-37 shows our outdoor switchgear profile.

Figure 11-37: 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 and other tests provide a good indication of potential insulation breakdown and circuit breaker condition. We also carry out thermal inspections to identify thermal anomalies and ultrasonic & transient earth voltage (TEV) measurements to monitor any partial discharge activity. Routine testing and monitoring across the whole fleet enables trends to be tracked, enabling early identification of potential failure and continuous condition monitoring.

We apply our risk framework to this asset fleet with the key input being 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

CB 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	35–50	35	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 (competence, 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. Also, 25% 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:

Two 11 kV switchboards of the same type at different zone substations that 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 had not been 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 to undertake a full condition assessment 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 works to replace them are at various stages.

We identified a potential failure mode through 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 these works appear to have addressed the issues.

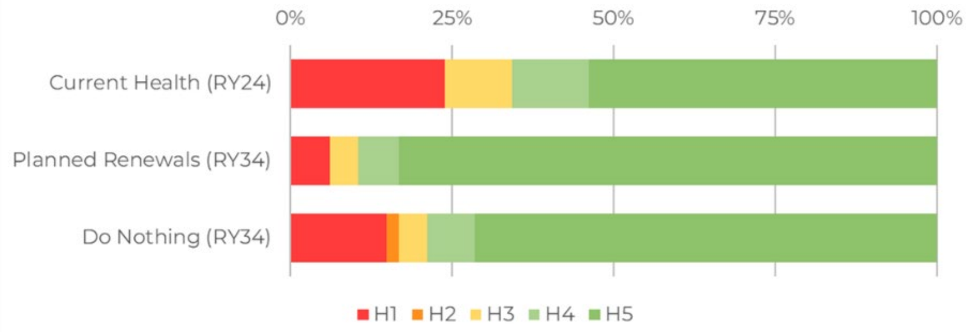
We have a population of indoor-type minimum oil circuit breakers (ABB type HKK) that have been installed in poorly designed locally fabricated outdoor cubicles in our switchyards. One installation of these circuit breakers has been set up as a switchboard where the circuit breakers can be withdrawn as 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 to be cost-effective, but we (and other EDBs) have experienced issues with these installation types. 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 oil in the circuit breakers.

Figure 11-38 summarises the current health profile for the outdoor circuit breakers. It illustrates that approximately 20% of the fleet has already exceeded its life expectancy (H1) and also shows the health profile forecast for the planning period with no expenditure.

Figure 11-38: Projected outdoor switchgear asset health

Figure 11-39 summarises the current health profile for the indoor switchgear. The planned level of expenditure will enable us to manage a critical safety and reliability risk. The planned renewals programme will significantly improve overall fleet health.

Figure 11-39: 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 our personnel due the potential failure mode where an arc flash (fault between phases or earth) occurs, which can release a large amount of energy and cause an explosion. Indoor switchgear is housed in confined spaces and a large proportion of the 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 PSA 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, externally vented, uses vacuum interrupters, and does not contain SF_6. This reduces the type of risks we face on older equipment to very low levels.

Outdoor switchgear has a lower risk profile compared to indoor switchgear as it is typically comprised of individual circuit breakers physically separated by a distance rather than installed in a single switchboard. This reduces the impact on reliability of an individual failure and 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 works to replace the insulators is at various stages. Table 11-27 summarises the key risks identified in the fleet.

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 NERs 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
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 and criticality. 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 and criticality is assessed from a combination of both SAIDI and VoLL to measure the impact of an asset failure.

For outdoor switchgear fleet, we use an age-based model to forecast renewal requirements and we intend improve and include criticality assessment in the forecasting framework. Where a significant amount of outdoor switchgear is planned for renewal, we consider conversion to indoor modern 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 adding a bus section circuit breaker and busbar protection, less 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, and any considerations regarding availability of spare parts or other maintainability concerns, to determine the overall network replacement needs. We intend to further improve the AHI models to include condition-based end-of-life drivers.

In some instances, we may replace switchgear earlier than forecast where condition has been assessed to deteriorate more quickly than anticipated or efficiencies can be achieved by combining replacement with other zone substation works. Generally, switchgear renewals are grouped with other zone substation renewals and delivered as one 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.

The following priorities have been identified for replacement:

INDOOR OIL FILLED SWITCHGEAR END-OF-LIFE REPLACEMENT
In consideration of this risk, our approach to indoor switchgear renewal includes a programme of oil-filled switchgear replacements.

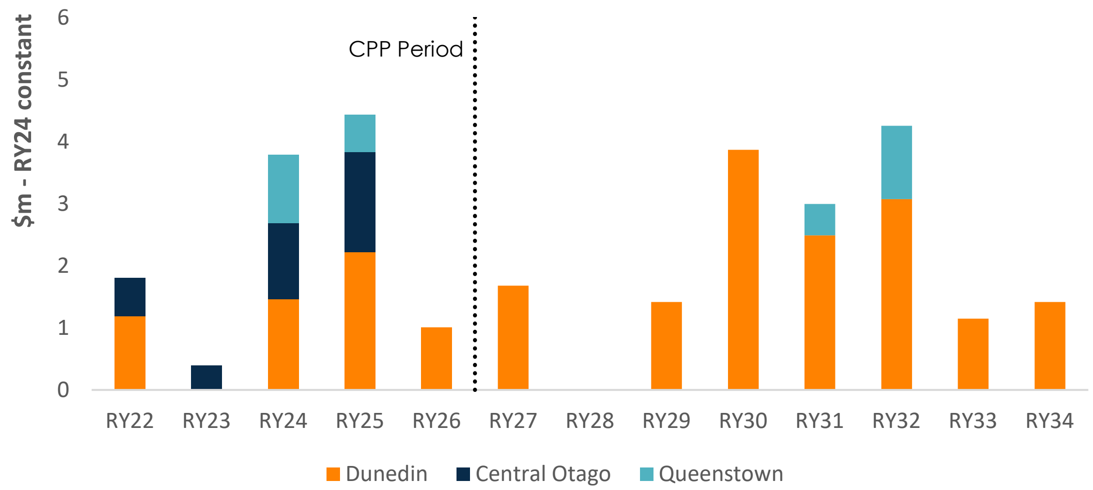
REPLACEMENT OF INDOOR SWITCHGEAR INSTALLED IN OUTDOOR CUBICLES
An indoor SF_6 11 kV circuit breaker (ABB type HPA) in an outdoor cubicle/switchboard arrangement failed at a Central Otago zone substation. Oil was expelled from the breather of one of the minimum oil 11 kV circuit breakers (ABB type HKK) installed in an outdoor cubicle.

DISPOSAL

We dispose of all switchgear when it has reached end-of-life and is removed from service. Where the same make/model switchboard remains in service at another site, we will assess it for retention of spare parts and keep them 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.

FORECAST EXPENDITURE

Figure 11-40: Capex forecast indoor switchgear by region (RY24 constant, $m)



11.6.4. Ancillary zone substation equipment

The 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 the 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 a 2 MVA generator installed at the Omakau zone substation and work is currently in progress to install a second 2 MVA generator 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 types and arrangements and can be 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 end of life 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 comprised 16 injection plants injecting into distribution circuits at each Dunedin zone substation. We had 15 rotary plants, installed between the 1950s and 1970s and one static plant installed in the 1990s. These have been progressively decommissioned, and to date only five remain. All of these are forecast to be decommissioned by the end of 2024. 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.

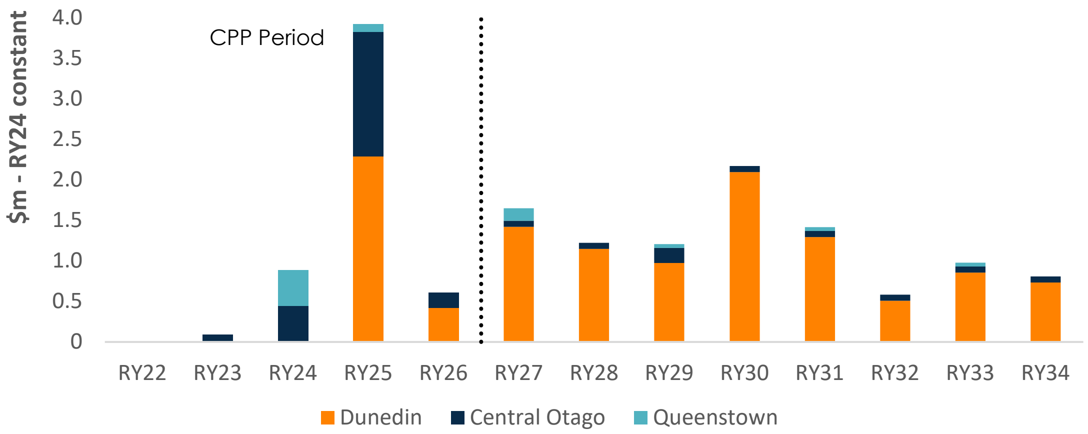
The condition and health of our ancillary equipment is assessed during routine inspections and preventive maintenance. As this fleet contains a variety of equipment, we do not have a single framework for assessing asset health. Our general approach is to carry out relevant tests and visual inspections 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 rust-kill/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, with a design life expectancy of 15 years, are approaching end of life, with the majority now 13 years old. The coupling cells are also same age as the converters but have longer life expectancies, except for the Alexandra coupling cells that were installed in the 1980s.

FORECAST EXPENDITURE

Figure 11-41: Capex forecast ancillary zone substation equipment by region (RY24 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.

OVERALL ZONE SUBSTATION FORECAST EXPENDITURE

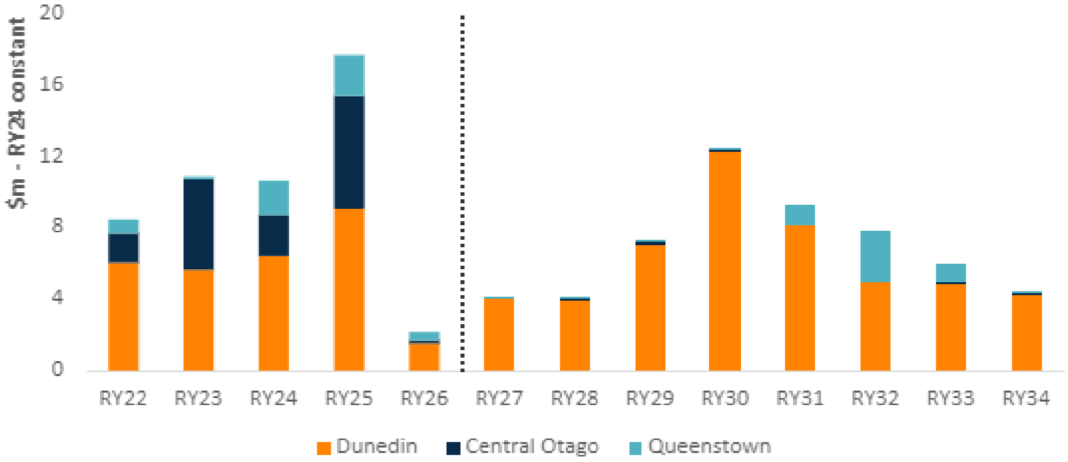
There is a notable change in the forecast for zone substation renewals from previous forecasts.

The following factors have contributed to and been considered in determining the AMP24 forecast:

- Shift in the driver for several projects, from primary driver *Renewal* to primary driver *Growth*
- Enhanced Cost Estimation processes
- 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

Consideration of the overall network resilience following the completion of growth projects, where more options for back-feeding are achievable.

Figure 11-42: Total Capex forecast zone substation expenditure by region (RY24 constant, $m)



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:

- HV ground-mounted switchgear
- Pole-mounted switchgear (which includes air break switches (ABS), pole-mounted reclosures and sectionalisers, pole-mounted fuses and links)
- LV enclosures, which includes underground link boxes and aboveground pillars
- Ancillary distribution equipment

Each of these fleets is described in the following sections.

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

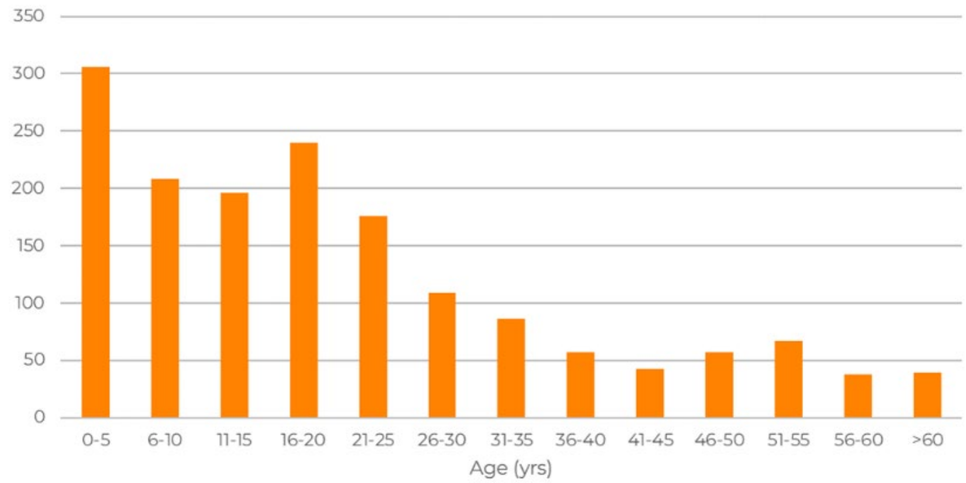
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Statter Oil-filled	103	0	0	103
Long & Crawford Oil-filled	197	0	0	197
ABB SD Series Oil-filled	227	182	249	657
ABB SafeLink2 SF_6 Insulated	140	181	125	446
ME/ETEL Air Insulated	2	113	58	173
Siemens 8DJH SF_6 Insulated	0	2	1	3
ENTEC HALO Solid Dielectric	18	10	5	33
J&P Oil-filled	2	0	0	2
Reyrolle Oil-filled	3	0	0	3
Tamco Vacuum Insulated	3	0	0	3
Magnefix Solid Dielectric	0	0	1	1
Total	**695**	**488**	**439**	**1622**

ASSET AGE

Our Fleet Strategy documents define type-specific expected useful lives ranging from 40 to 70 years, informed by condition. Figure 11-43 depicts the fleet's age profile.

The fleet includes 252 oil filled switchgear units that are already beyond the EEA AHI Guide Maximum Practical Life (MPL) of 40 years, with 46 of those units already beyond 60 years. Another 135 oil filled switchgear units will exceed the EEA AHI Guide MPL over the planning period. Of the 858 ABB SD Series 2 and L&C oil filled switch hear units, 613 have had an invasive maintenance overhaul completed in recent years, in the planning period the remaining 245 units will have had an invasive maintenance overhaul if not replaced.

Figure 11-43: Ground-mounted distribution switchgear fleet age profile

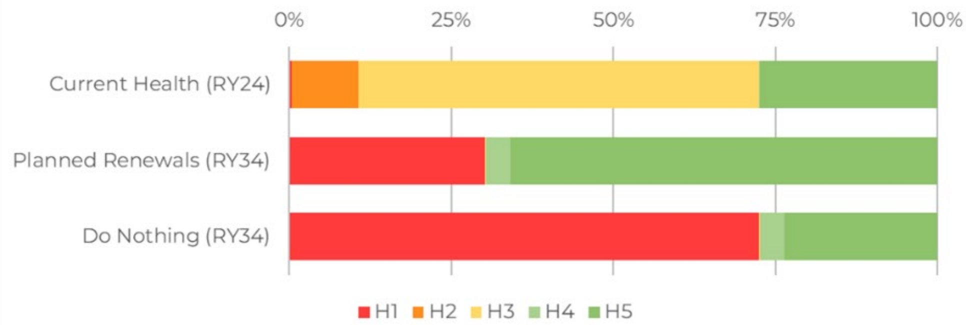


ASSET HEALTH

Our ground-mounted switchgear fleet is generally considered to be in good condition with only a small number of assets currently identified as H1 and with plans to implement a replacement programme as described below. The AHI of the ground-mounted distribution switchgear is calculated based on our AHI methodology described in Section 6.4. The AHI for this asset class is informed by expected life, maintainability, condition, age, and type.

Figure 11-44 depicts the current fleet AHI as well as the forecast AHI and the counterfactual Do Nothing scenario. 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 called "informed effective life" in the model.

Figure 11-44: Projected ground-mounted distribution switchgear health index



ASSET PERFORMANCE AND RISK

Our historical outage records indicate relatively few outages due to faulty ground-mounted switches. However, we do presently have a number of switches that are in poor condition or 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 as these are installed on the ground in urban areas, these assets have an elevated risk profile (criticality with respect to public safety) than other switchgear assets.

Specific asset performance and condition issues on the network include:

- Operational risks exist for specific models of Reyrolle oil filled switches, Magnefix, and Entec. These are being managed through planned replacement programs and operational restrictions until replaced.
- With a long serviceable life, spare part availability and retention of technical knowledge to maintain units create potential for obsolescence from the perspective of ability to maintain. Where

relevant, this may require asset replacement to address the obsolescence of the switches.

As age is 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 beyond 60 years old. This demonstrates an elevated risk from this asset fleet.

Potential future risks that have been identified include:

- 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 if not separately replaceable.

Table 11-29 summarises the key risks in our ground-mounted distribution switchgear fleet.

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
Magnefix requires specialist operators and has a small orphan population	Operating personnel with specialist training Operating procedures Replacement programme
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 which creates 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, it is a risk prioritised approach which takes into account our ability to deliver, the type, age and condition, failure modes and maintainability of each asset.

The renewal strategy is defined in the Fleet Strategy, the year-to-year programme adjusted based on inspection and maintenance insights. The location of the asset is also taken into consideration, those in safety critical zones being prioritised. Assets identified to be 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 the ability to repair assets, rather than replace, and whether changes to the network topology would enable the asset to be decommissioned or if 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 considered 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 by RY64. 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 the current risk assessment resulting in the following sequence and timeframes:

- Replacement of all Eaton, J&P, Reyrolle, Statter, Tamco and Entec Halo units by the end of RY30
- Incorporation of ME/ETEL boxes in the programme and replacement by end RY50
- Replacement of Dunedin oil-filled L&C by end RY55
- Replacement of Dunedin oil-filled ABB SD Series 2 by end RY60
- Replacement of Central oil-filled ABB SD Series 2 by end RY64

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, we plan to ensure we have sufficient spares and critical spares in our stores along with our workforce trained to an appropriate skill level to manage the L&C and ABB SD Series 2 units due to the longer-term replacement timeframe. This will ensure these assets remain safe and reliable while on our network.

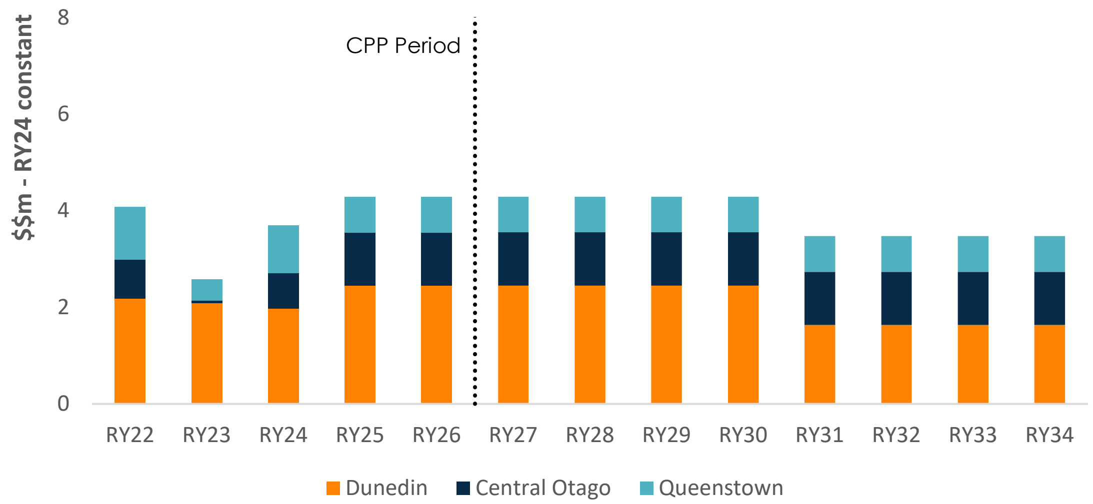
DISPOSAL

Removed ground-mounted distribution switchgear that will not be reused on the network is disposed of through the following the steps:

- Donor unit for parts
- Offered to other EDBs
- Oil recycled and reused
- SF_6 collected by third-party contractors approved to recover SF_6
- Steel collected by third-party scrap dealers

FORECAST EXPENDITURE

Figure 11-45: Capex forecast ground-mounted distribution switchgear by region (RY24 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, and are used from LV up to 66 kV. ABS 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 insulating medium consisting of oil or vacuum and are used to improve the reliability of our network by limiting the area impacted by faults. Reclosers have protection capabilities and can automatically open when a fault is detected and attempt to reclose in case the fault was transient. This helps improve the performance of our network. The protection and reclose setting can be configured for each device individually. Sectionalisers are gas insulated switches that can be located at the switch or remotely to de-energise parts of the network. Sectionalisers do not have any protection or automated functionality. 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.

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

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
ABS	571	383	139	1093
Reclosers	15	31	18	64
Total	**586**	**414**	**157**	**1157**

ASSET AGE

Our Fleet Strategy documents define the life expectancies of our pole-mounted switchgear.

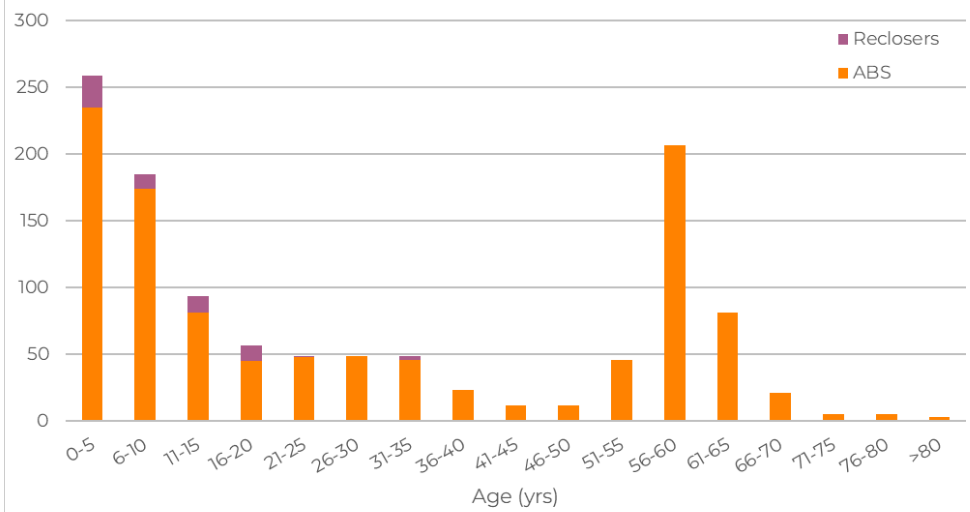
The life expectancies of our ABSs vary by type, ranging from 30 to 65 years.

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. Through the roll out of our OH inspection – including thermal inspections on these assets – we will be able to inform the AHI model, including shifting to condition-based criteria and verifying expected life, and thus focus spending where we know it is needed.

Figure 11-46 depicts the fleet's age profile.

Figure 11-46: 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.

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 after sales 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 and experience of personnel are:

- Due to infrequent use, mechanisms seize and maintenance or renewal is required (particularly common in coastal areas)
- We are experiencing corrosion issues with some of our older pole-mounted switches, particularly in coastal areas
- We found 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 and so they are tagged *Do Not Operate* (DNO). This 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 11-47 and Figure 11-48 below compare projected AHI in RY34 following planned renewals for pole-mounted switches and reclosers, respectively, with a counterfactual ‘do nothing’ scenario. 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 – through our new OH inspection programme we are starting to get better quality information that will help us to 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 11-47: Projected pole-mounted switch asset health

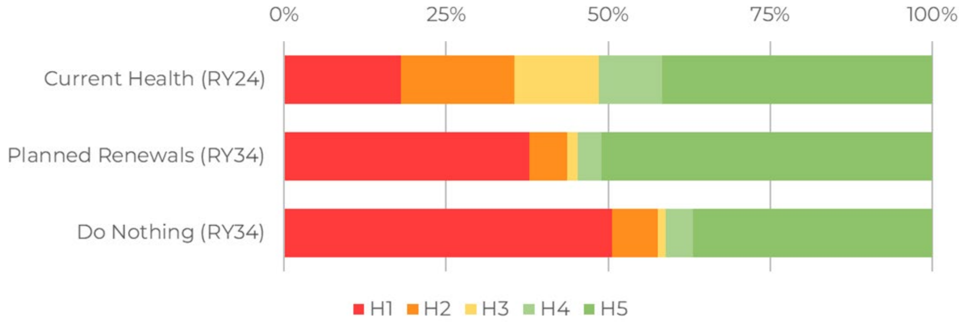
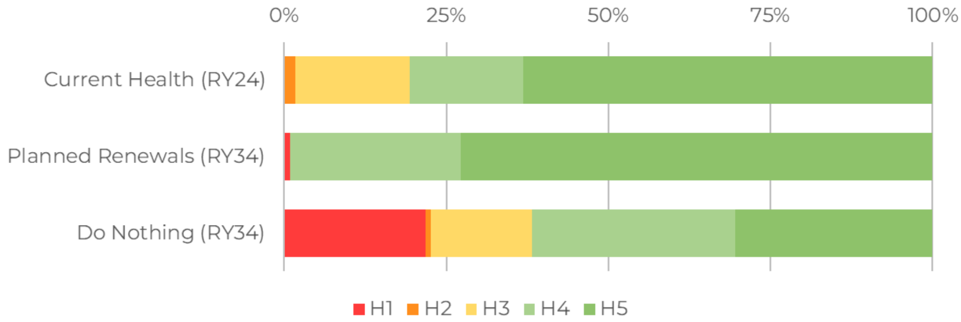


Figure 11-48: Projected recloser asset health



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, as they have tight clearances between phase bushings. We have had isolated problems with some controllers from our recloser fleet, and the 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.

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

Risk/Issue	Mitigation
Lack of easement on site (most sites installed post-1992 existing use rights consideration)	Gain easement New site chosen when renewing or adding, bypassing if easement cannot be gained on 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 includes 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 it 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 switch and 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.

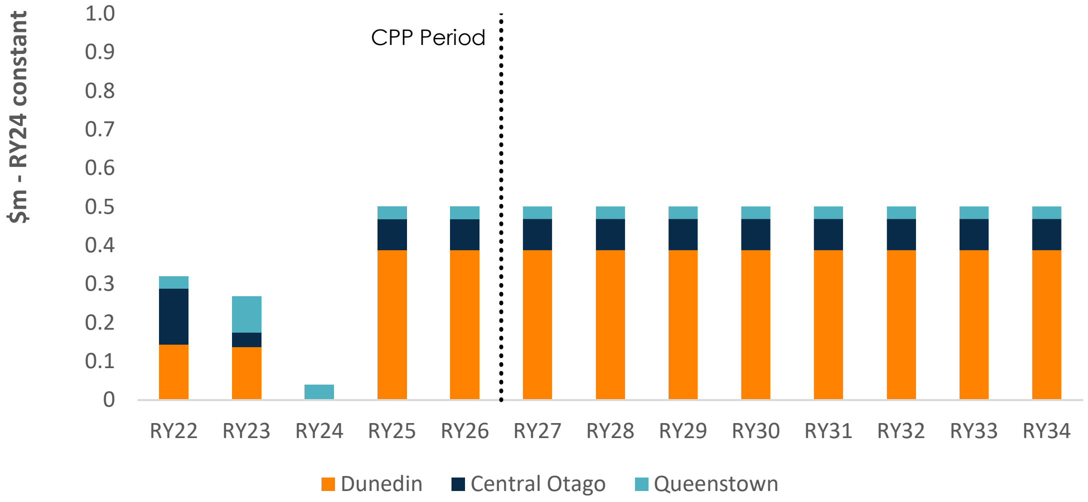
DISPOSAL

Removed assets not to be reused on the network are disposed of through the following the steps:

- Donor unit for parts
- Oil recycled and reused
- Steel collected by third-party scrap dealers

FORECAST EXPENDITURE

Figure 11-49: Capex forecast pole-mounted distribution switchgear by region (RY24 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 16,000 LV enclosures with 258 are underground link boxes and 16,943 pillars.

Table 11-32: LV enclosure population by sub-network

	Population			
Asset Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Link boxes	258	0	0	258
Pillars	7850	5879	3214	16943
Total	**8108**	**5879**	**3214**	**17201**

ASSET AGE

Our Fleet Strategy documents define the life expectancies of 40 years for our LV enclosures.

The average age of our LV enclosures is less than 40 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 11-50: Low voltage pillar age profile

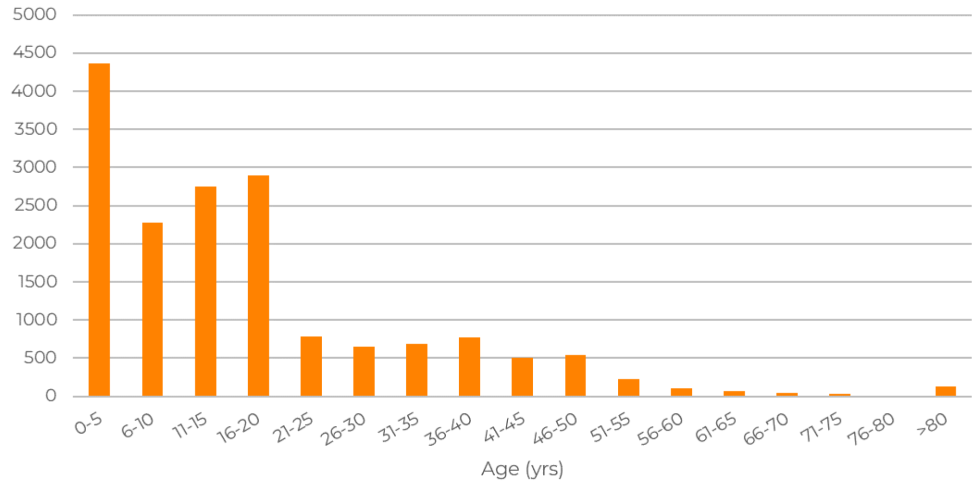
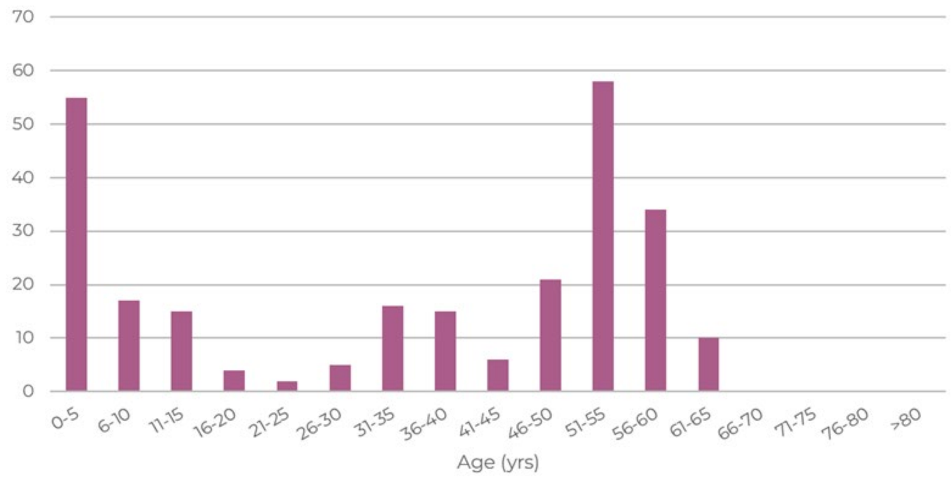


Figure 11-51: Low voltage link box age profile



ASSET HEALTH

We began assessing the condition of LV enclosures in RY19, and will complete 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 are finding 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 require relocation to be accessible.

Based on asset health, 11% of our LV enclosures have reached EOL. Most EOL enclosures are in the Dunedin sub-network, which 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 relatively good, but there is a high reactive renewal component for these assets due to third-party damage.

Figure 11-52 and Figure 11-53 compare projected asset health of our LV pillars and LV link boxes in RY34 following our planned programme of renewals, with a counterfactual 'do nothing' scenario. A 'do nothing' approach would increase the number of H1 enclosures from 11% to 21%.

Figure 11-52: Projected low voltage pillar asset health

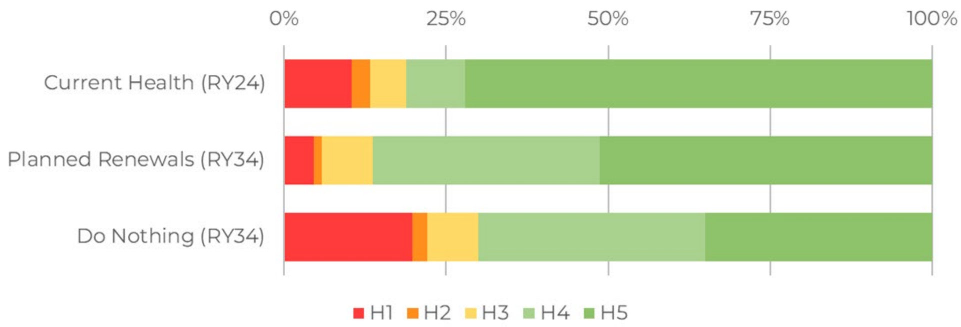
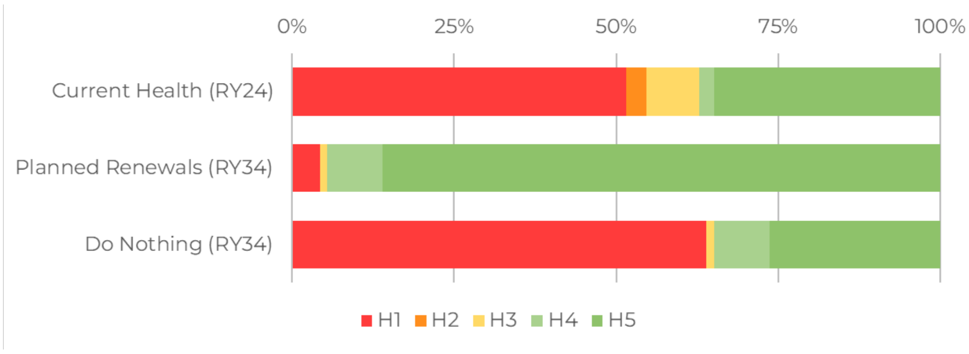


Figure 11-53: Projected low voltage link box asset health



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.

Table 11-33 summarises the key risks identified in relation to our LV enclosures fleet.

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

We forecast the required budget and expected volumes for replacement of LV enclosures based on our AHI and risk assessment methodology, which includes inputs based on the outcomes of asset inspections. 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 enclosure and the defect(s) found. We also replace LV enclosures reactively in the event of vehicle damage or vandalism.

As described above, there is also a need for relocation of LV enclosures where they have become obstructed by other infrastructure such as retaining walls, fences or gardens.

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 the enclosure cannot have its defects remediated on-site, it will be replaced with a new like-for-like or equivalent unit. With the above ground solutions, some smaller LV enclosures 'clustered' together can be combined into one larger capacity LV enclosure which saves space, capacity, and safe operation during faults.

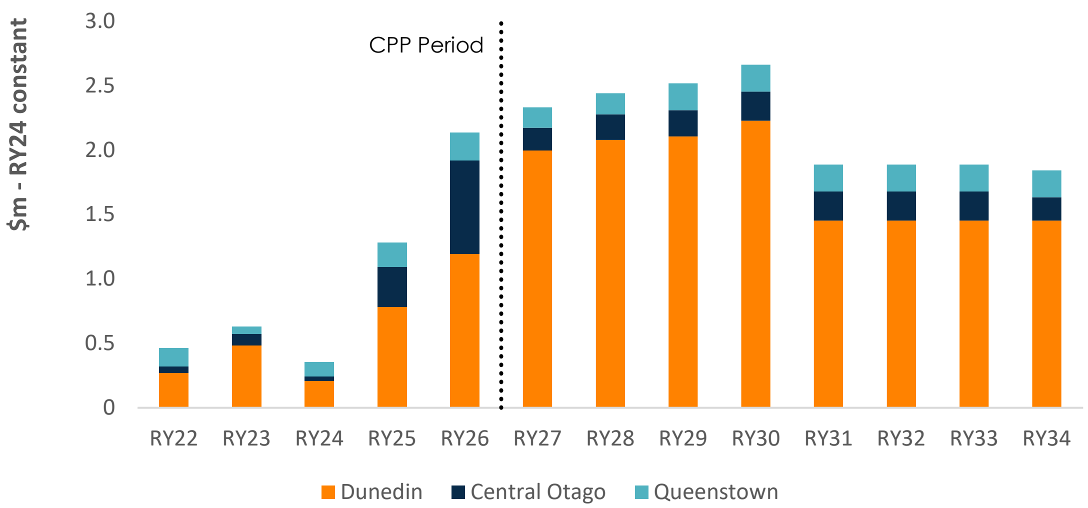
DISPOSAL

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 programme of replacements and we now forecast LV enclosures renewal Capex of approximately $11.1m during the planning period, as shown below. This expenditure includes any cable costs required to relocate enclosures for condition-based reasons (not customer driven).

Figure 11-54: Capex forecast LV enclosures by region (RY24 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 have 17 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.

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 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, the underground substation will be replaced by a ground-mounted substation near the existing location so it can be connected to the same point on the network and require minimum change 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:

- A new above-ground site further from the existing site
- Decommissioning the existing site and reconfiguring the local network
- Refurbishment of the substations structure and installation of 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 to be undertaken by council and other asset owners in the Dunedin CBD
- Replacement with above ground assets will reduce the reliability and resiliency risk associated with flooding in the CBD area and the safety risks associated with working in confined spaces

DISPOSAL

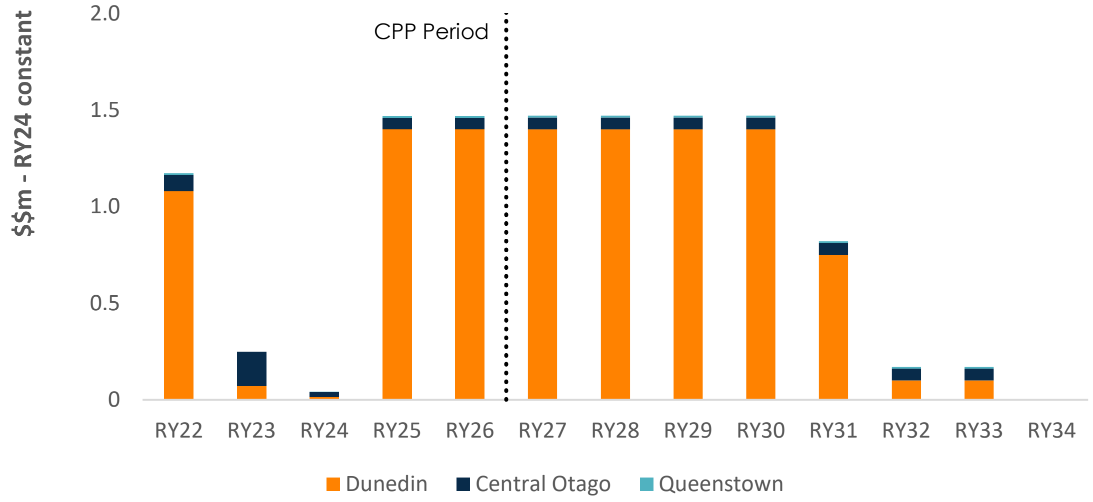
Special consideration must be given to decommissioned underground substation sites as to whether they will be retained as sites or filled in, requiring discussion with council and other asset owners in the Dunedin CBD.

FORECAST EXPENDITURE

Our forecast renewal expenditure for underground substations is based on the replacement of a small number per year due to their inherent confined space risk and their end-of-life equipment, to create a steady programme of work. We plan to replace all 17 underground substations by RY30.

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.

Figure 11-55: Capex forecast ancillary distribution sub equipment by region (RY24 constant, $m)



11.8. DISTRIBUTION TRANSFORMERS

This section describes our distribution transformer portfolio and summarises how we manage the following four asset fleets:

- Ground-mounted distribution transformers
- Pole-mounted distribution transformers
- Voltage regulators
- Mobile distribution substations and generators

Voltage regulators are designed to automatically maintain voltage to a set level. The length of some of our 11 kV feeders necessitates the installation of voltage regulators partway along the feeders to maintain the correct voltage at the end of the feeder.

Mobile substations and mobile generators enable us to bypass permanent distribution substations, which enables support to both planned work and fault restoration.

11.8.1. Ground-mounted distribution transformer fleet

Ground-mounted distribution transformers are ground-mounted devices 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. Ground-mounted transformers 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 provides an overview of our ground-mounted distribution transformer fleet by size and sub-network.

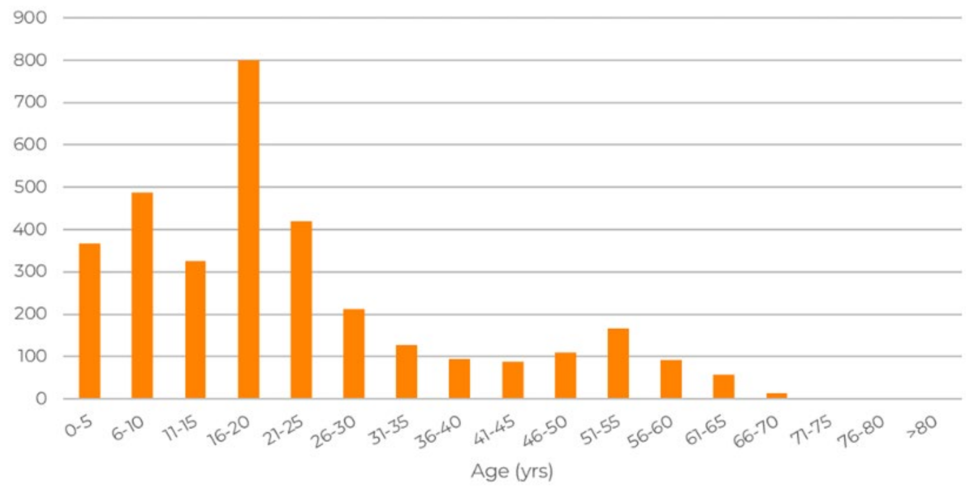
Table 11-35: Ground-mounted distribution transformer population by rating and sub-network

Rating	Dunedin	Central Otago & Wānaka	Queenstown	Total
0 to 100	164	860	505	1529
100 to 200	257	285	134	676
200 to 300	251	192	90	533
>300	377	126	123	626
Total	**1049**	**1463**	**852**	**3364**

ASSET AGE

The age profile is shown in **Figure 11-56** below. The average age is 22 years. There are also relatively few transformers that will exceed their expected serviceable life of 70 years within the planning period.

Figure 11-56: Ground-mounted distribution transformer age profile



ASSET HEALTH

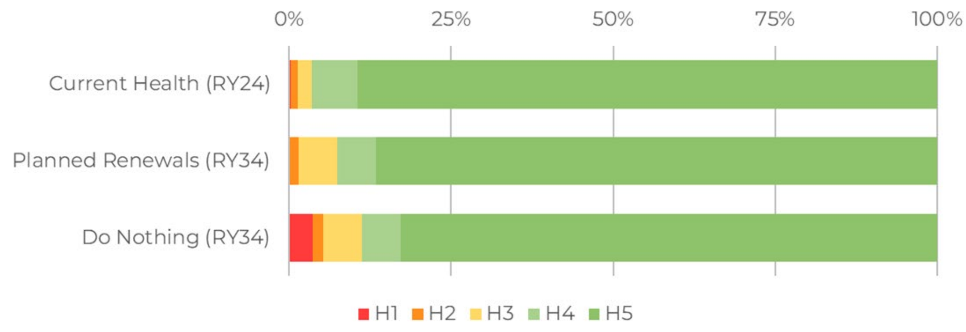
The overall health of this fleet is good, but a small number of renewals will be required each year to address issues with specific assets.

As we mature in our understanding and management of asset risk, we continue to refine our methods of assessing asset health. Previously, we had a purely age-based approach but as we build more information through inspections, we have been including the outcomes from inspections to our model. This is a hybrid approach that still leans more on the age, but we are continuously improving the model by incorporating more condition data. Consequently, we are currently drafting an inspection standard document, which will ensure a structured and quantitative approach to assessing the condition, ultimately enhancing expenditure decision-making.

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.

Figure 11-57 shows the AHI for ground-mounted distribution transformers.

Figure 11-57: Projected ground-mounted transformer asset health



ASSET PERFORMANCE AND RISK

We are in the process of updating our standard for inspection of this fleet, having completed the fleet strategy and documented all plausible failure modes. RCA investigations to date have not identified any systemic issues with this fleet.

A benefit of ground-mounted distribution transformers is that they are inherently more seismically robust than pole-mounted transformers but still require seismic restraint.

Table 11-36 sets out the key risks identified in our ground-mounted distribution transformer fleet.

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, Veg 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 which accelerates 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

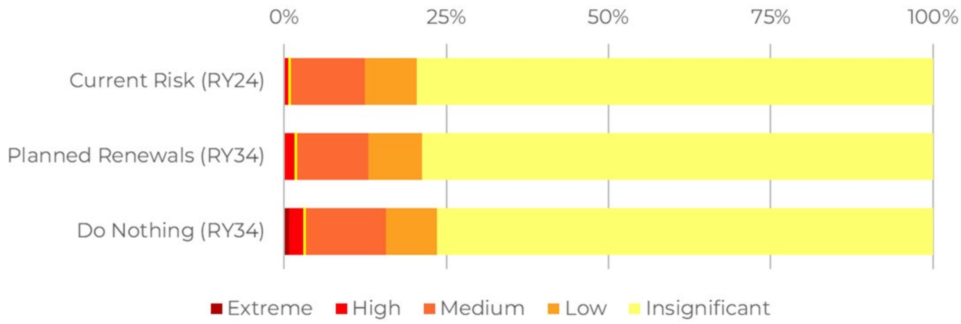
Through RCA we have identified the following causes for distribution transformer failures:

- HV fuse blowing (7)
- Loose connections (6)
- Lightning strike (2)
- Low oil (3)
- Tap-change required (1)
- Foundation tilt (1)
- Undetermined (3)

These 23 records of distribution transformer failures have been accumulated over the past approximately 18 months. Note that this is for both GM and PM transformers, and will form the basis of trending once we have established a relevant data set.

We plan to take into account all learnings from these analyses in the production of our new Distribution Transformer Inspection Standard. Figure 11-58 shows the projected risk for our ground-mounted distribution transformers.

Figure 11-58: Projected ground-mounted distribution transformer risk



REPLACEMENT/RENEWAL

We use a Repex approach for forecasting ground-mounted distribution transformer renewals.

We prioritise replacement, with remaining asset life and current health constituting the key considerations. The following are the strategic considerations:

- Transformers between 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
- GM transformers greater than or equal to 500 kVA at 100–130% utilisation with age between 30 and 60 years old will be subject to a TCA assessment
- Transformers inside buildings or extreme access at 100–130% utilisation and between 30 and 60 years old will be subject to a TCA assessment
- We coordinate ground-mounted transformer replacements with ground-mounted distribution switchgear replacements
- 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. Replacement of these units will largely occur beyond the AMP period. The outcomes with respect to AHI and risk are shown in Figure 11-57 and Figure 11-58 above.

DISPOSAL

We dispose of ground-mounted distribution transformers when decommissioned. The principal components – steel, copper, and oil – are recycled. We keep 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 a 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.

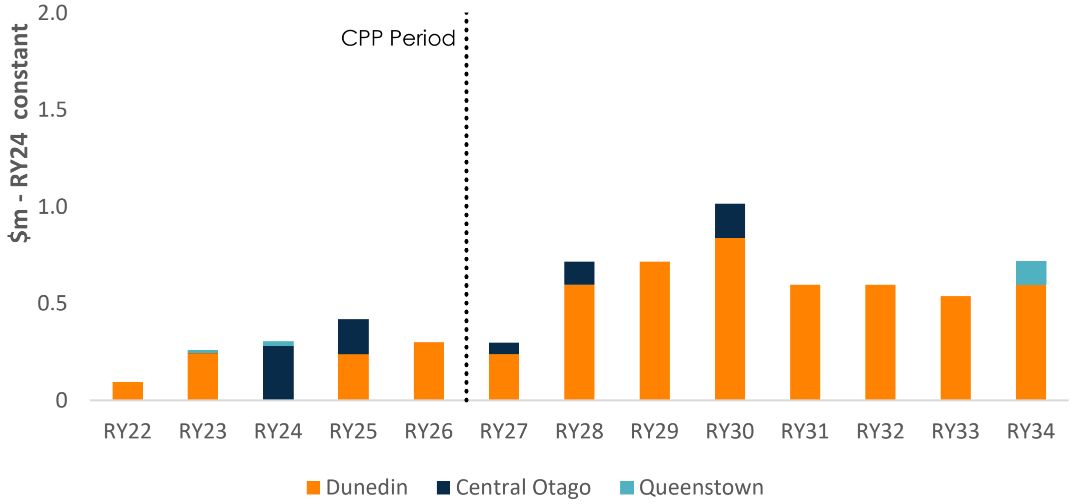
FORECAST CAPEX EXPENDITURE

Due to the age of the fleet, we have not replaced many ground-mounted distribution transformers in recent years. However, we expect an increasing level of renewals as our fleet ages, and have increased our renewal quantities to target specific assets relating primarily to obsolescence, age, and condition.

The key benefit of our planned renewal programme is ensuring continued reliability of service to consumers. Secondary benefits are mitigating low probability safety incidents during transformer failure and mitigating environmental risk of oil spill from aged or failed transformers and ensuring security of the asset accordingly.

Our forecast ground-mounted distribution transformer renewal Capex is shown in Figure 11-59. The total forecast expenditure over the planning period is $5.9m.

Figure 11-59: Capex forecast ground-mounted distribution transformers by region (RY24 constant, $m)



11.8.2. Pole-mounted distribution transformer fleet

Pole-mounted distribution transformers, like ground-mounted transformer units, 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 can be as large as 500 kVA (pedestal mounted).

Pole-mounted transformers are usually located in rural or suburban areas with lower customer density and smaller loads. We have a small quantity of single wire earth return (SWER) transformers supplying a SWER system in our Dunedin sub-network. We have a small number of pole-mounted 11/6.6 kV auto transformers to interconnect parts of our distribution system that operate at different voltages.

Table 11-37 provides 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

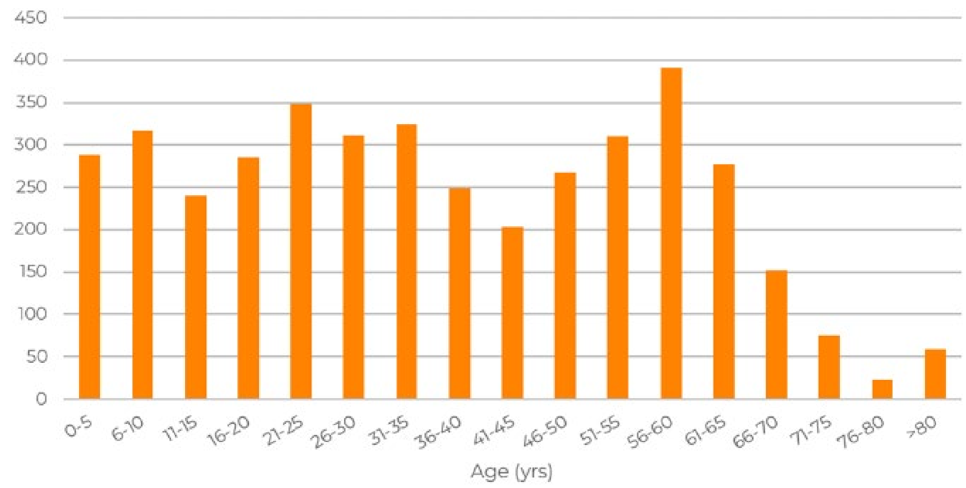
Rating	Dunedin	Central Otago & Wānaka	Queenstown	Total
≤15	613	783	209	1605
15 to 30	453	619	152	1224
30 to 120	354	461	106	921
120 to 200	111	29	3	143
> 200	218	7	2	227
Total	**1749**	**1899**	**472**	**4120**

ASSET AGE

Figure 11-60 shows the age profile of our pole-mounted distribution transformers. The average age is 36 years but the chart shows a fairly even distribution of ages across the fleet.

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 11-60: Pole-mounted distribution transformer age profile



ASSET HEALTH

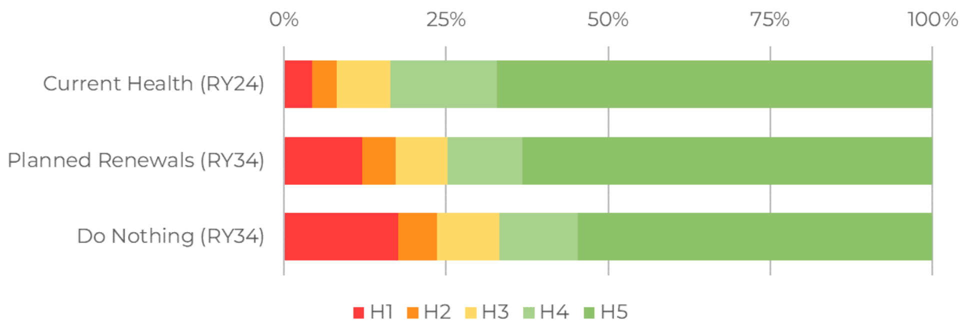
We do not currently have a high level of confidence in the asset data related to this fleet as historically we have not systematically captured and recorded condition information. As a result, the AHI of this fleet is largely informed by age and the expected asset serviceable life. However, where we 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.

We have updated our asset fleet strategy and as a result, we will be inspecting all pole mount transformer as part of the Overhead Inspection programme. In particular, transformers that are over 20 years old and 200 kVA and above, will have a detailed transformer inspection under the 5-year cyclic inspections.

The ongoing progress in maturing and refining our inspection programme will provide us with the information we need to continue to progress towards 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 11-61 shows the current and projected AHI of the fleet, together 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 is based on a model largely driven by age. 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 11-61: Projected pole-mounted distribution transformer asset health



ASSET PERFORMANCE AND RISK

We are in the process of updating our standard for inspection of this fleet, having completed the fleet strategy and documented all plausible failure modes. RCA investigations to date have not identified any systemic issues with this fleet. Table 11-38 sets out the key risks identified in our pole-mounted transformer fleet.

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 of 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/into the transformer	Inspection and maintenance, Vegetation Management
Earthing issues	Inspection/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 is currently focus 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 the risk framework.

Distribution transformers of 100 kVA and below are categorised as small transformers. With this, we generally replace them reactively upon failure. This is cost-effective as the impact on consumers is limited. We have recently replaced a large number during pole replacements, and this will continue, albeit at a lower rate.

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. This will involve proactive replacement of larger, aged pole-mounted units (which present a specific public and worker safety risk) with ground-mounted units, together with condition-based replacement of other pole-mounted transformers.

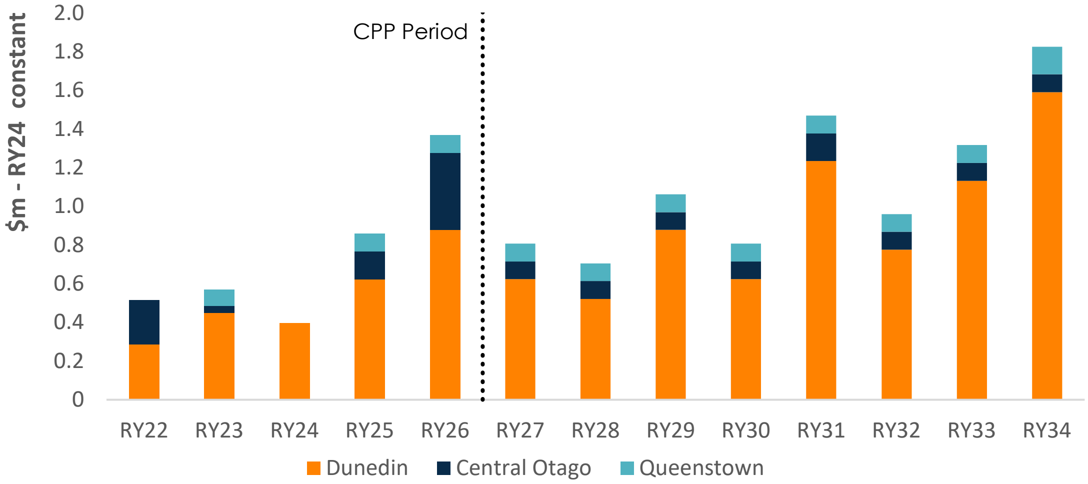
Where replacement is required, our preferred option is to retain pole-mounted transformers where possible. This is supported by consultation with communities on the price implications of underground conversions for visual amenity reasons. Offloading and decommissioning is also considered when assessing options for replacement of pole-mounted distribution transformers.

DISPOSAL

The disposal process is similar to that for ground-mount transformers.

FORECAST EXPENDITURE

Figure 11-62: Capex forecast pole-mounted transformers by region (RY24 constant, $m)



11.8.3. Other distribution transformers

VOLTAGE REGULATORS

Voltage regulators are designed to automatically maintain voltage to 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.

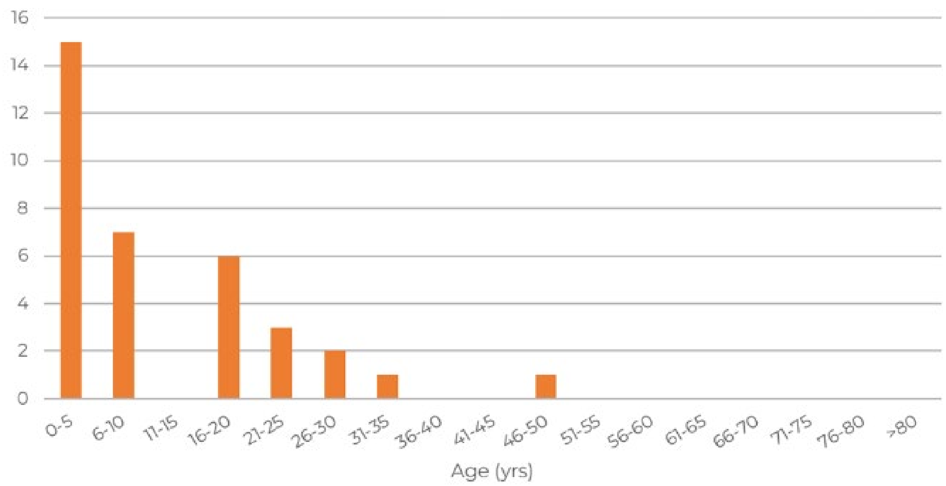
Voltage regulators comprise an auto transformer, control device, and communications to our SCADA system. While our fleet of voltage regulators are primarily controlled by digital controllers, a few older controllers with ad-hoc setups and limited visibility of settings remain in service.

We have a total of 32 voltage regulators, of which 22 are in Central Otago, 2 in Dunedin, and 8 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. There are no voltage regulators that will exceed their expected life during the AMP forecast period.

Figure 11-63: 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 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 uncompliant voltage	Inspection, preventive maintenance, and replacement plan
Lack of easement on-site (most sites installed post-1992 existing use rights consideration)	Gain easement New site chosen when renewing, or add a bypass if an easement cannot be gained on the existing site
Mismatched sites losing synchronism, leading to non-compliant voltage	Overall plan to 'rematch' up 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 Gain approval to hold strategic stock of complete units for the one or two sizes chosen Generic construction across of future sites so rotating units becomes a 'plug and play' arrangement rather than a re-build 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 and units running abnormally will likely not achieve expected life, such as sites running at high loading, mis-matched single-phase units or with units performing additional tapping. As a result, some may be replaced based on adjusted life expectancies.

We prioritise replacement with key considerations on the AHI and prioritise based on risk. The focus of our future renewal plan is on:

- Replacing voltage regulators at the Cardrona site in RY25 as they are no longer fit for purpose

- Replacing voltage regulators at the Macandrew Bay site in RY31. This was installed in 1976 and may have been 2nd hand at that time. The site also has the challenge of being 3 MVA three-phase ground-mount site so 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 and then the remainder of the unit principal components of steel, copper, oil are recycled.

FORECAST CAPEX EXPENDITURE

The forecast expenditure allows for replacement of two units, one in Cardrona in RY25 and one in Dunedin in RY31.

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. They 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 supplying 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 substations	Lanyard operating system
Injury from falling off mobile substation	Edge protection system installed on top during usage

REPLACEMENT/RENEWAL

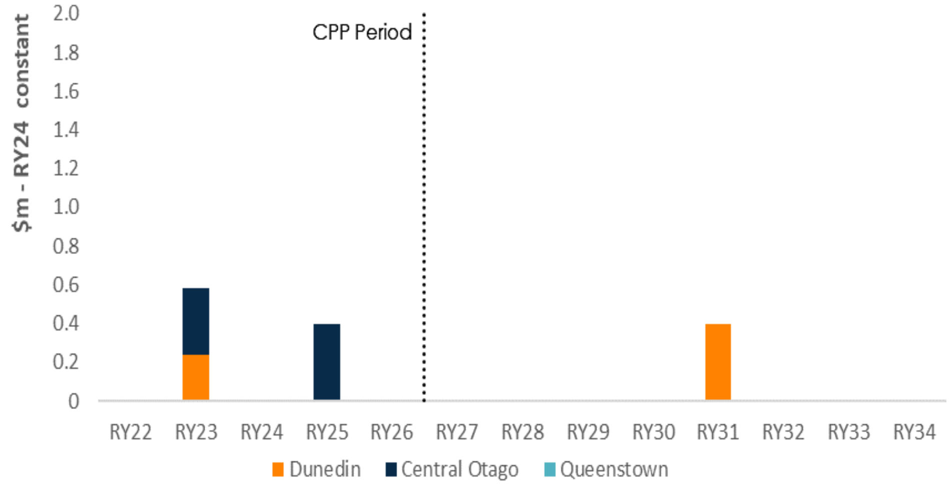
There is a requirement to operate the RMUs at a distance with a lanyard system due to arc flash levels for the mobile distribution substations. With the old age of the trucks, we have had rust issues that require ongoing repairs to obtain a certificate of fitness (COF). An LV board upgrade is soon due on the 300 kVA mobile distribution transformer.

We plan to investigate options around 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 with options such as a hydrogen hybrid and biodiesel.

We will replace our mobile distribution substations and mobile generators when their condition becomes poor, they become uneconomic to maintain, too unreliable to operate, or begin to present a significant safety risk.

FORECAST CAPEX EXPENDITURE

Figure 11-64: Capex forecast mobile distribution substation and generators by region (RY24 constant, $m)



11.9. SECONDARY SYSTEMS

This section describes our secondary systems portfolio and summarises how we manage the following four 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 overall integrity. They typically have shorter service lives and are low-cost compared to primary plant components. These systems provide various functions, including protection systems for rapid fault detection and safe zone substation operations; DC systems ensuring power supply in the absence of AC; and RTU assets 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 ensuring compliance with electricity codes.

11.9.1. Remote terminal unit (RTU) fleet

RTUs are an integral component of our 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, manage capacitor bank switching, and implement specialised protection schemes during contingency situations. We use various communication mediums with our RTUs, including 4G, fibre, microwave, and UHF radios to cater for the higher bandwidth and polling requirements.

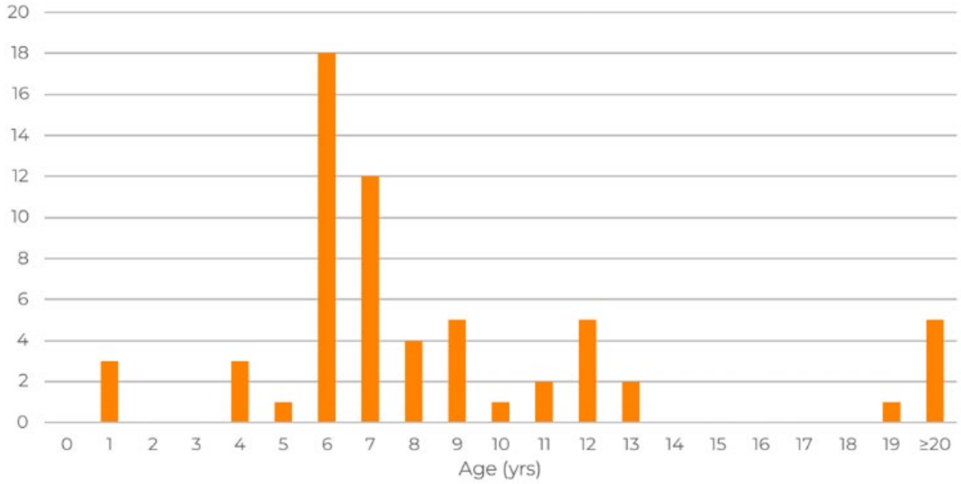
While the majority of our RTUs are situated in zone substations and GXPs, some are installed in outdoor locations. Our SCADA system and RTU fleet is generally in good condition. As such, we are now in steady-state and do not have any significant work planned in this portfolio over the planning period.

We have a total of 65 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

Most of our RTUs are less than 20 years old, though some have exceeded their expected life of 15 years. RTUs replaced 6 to 7 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 adapted good industry practice and our devices use standard DNP3 protocol over TCP/IP communication to our SCADA master station. We 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.

Figure 11-65: RTU age profile



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 through stocking of 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 that 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, having serial communication and a fixed number of input and output contacts.

Table 11-41 sets out the key risks identified in relation to our RTU fleet and their associated mitigations.

Table 11-41: 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. Firmware updates and CPU upgrades have been implemented 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.

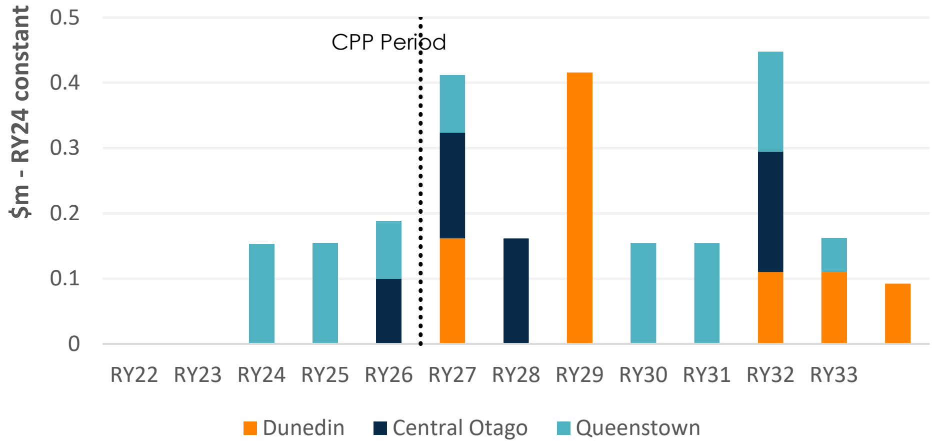
Where possible, we coordinate the replacement of RTUs with other project works, such as zone substation and protection renewals.

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

Figure 11-66: Capex forecast remote terminal units by region (RY24 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 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 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.

In the table, the protection functions represent the primary plant the relays are protecting. The complexity (and hence cost) of protection varies by protection function.

A protection scheme consists of multiple fault detection functions, for example a feeder relay may consist of earth fault and three diffident overcurrent functions for different types of fault and/or speeds of detection. If a protection scheme is implemented using electromechanical relays it will require a relay for each protection function. A protection scheme implemented with numerical protection relays will typically have a single numerical protection relay providing several protection functions.

Numerical schemes make around 52% of our raw population of protection relays, static 9% and electromechanical 39%.

Table 11-42: Protection asset population by type and sub-network

Relay Type	Dunedin	Central Otago & Wānaka	Queenstown	Total
Electromechanical	293	5	0	298
Static	28	20	23	71
Numerical	239	131	68	438
Total	**560**	**156**	**91**	**807**

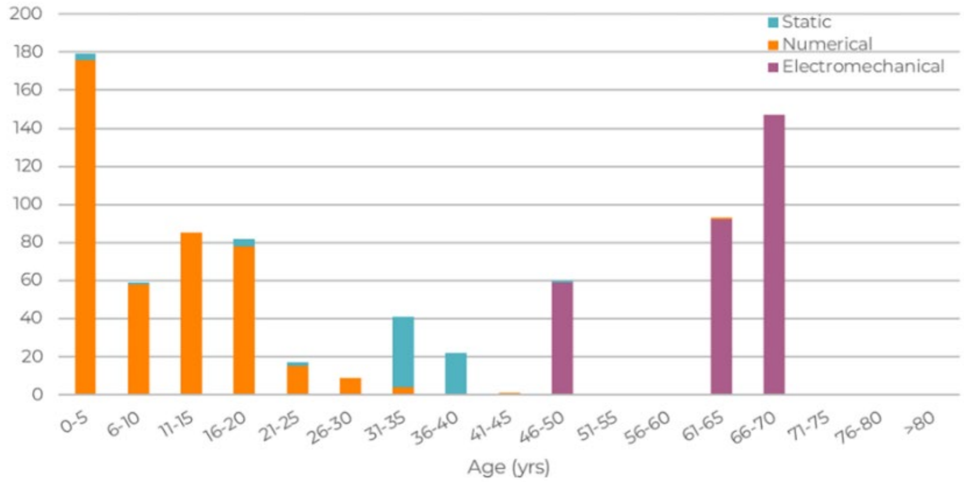
ASSET AGE

Figure 11-67 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 end-of-life 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.

Many 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 11-67: Protection relay age profile



ASSET HEALTH

Overall, the 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.

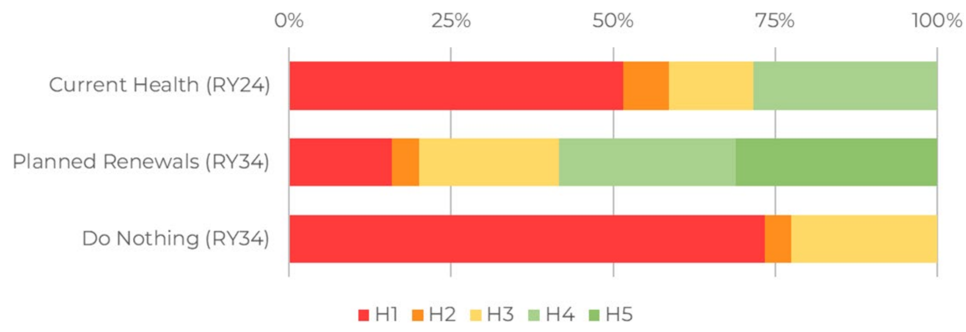
Electromechanical and static relays are old and largely obsolete technology with very limited spare parts and manufacturer support and very few technicians with the skills to service them. The functionality of these relays is usually limited to a single protection function, so multiple relays are required for each protection scheme, and they also have 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 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 lack manufacturer support, 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 microprocessor-based technology and susceptibility to excessive heat (addressed through substation air conditioning) numerical relays typically indicate malfunctions.

Figure 11-68: 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 11-43 sets out the key risks we have identified in our protection fleet and their associated mitigations.

Table 11-43: 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
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 to remove from service (during the planning period) all electromechanical relays and all other relays that are obsolete/have reached end-of-life. 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:

- **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 are experiencing an increasing number of protection relay maloperations, primarily due to the settings 'drifting' on electromechanical and static relays.
- **Functionality:** Modern numerical relays provide significant additional functionality that enables us, among other things, to improve management and operation of our network by 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 philosophy/standard. Most of these will be brought up to standard when they are replaced. Some lower priority protection gaps will remain, and we will further investigate the appropriate timing to address these gaps following completion of the 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/review event data and remotely modify protection logic/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 use as spares will be retained. Disposal requirements are minor and similar to other electromechanical or electronic devices. Some of our existing Buchholz devices contain mercury and we will use appropriate disposal methods when these are replaced.

FORECAST CAPEX EXPENDITURE

We take a volumetric approach to protection renewal forecasts. Unit rates vary with the function of the relay, with bus zone or subtransmission protection relays having higher unit costs.

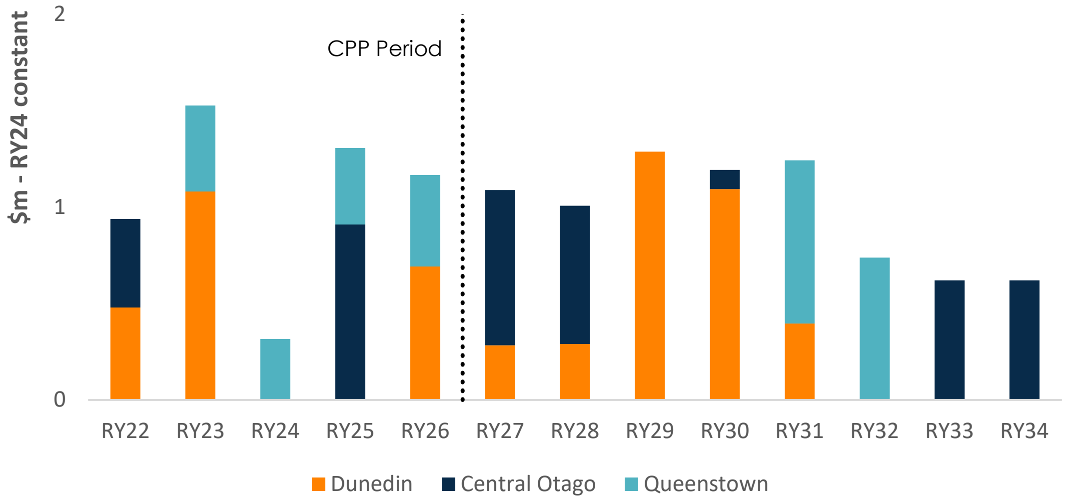
Up until RY18, expenditure on protection systems was low. We increased renewals during RY19, and we will remain at an elevated level through the CPP Period. There is a further uplift post-CPP Period as we move from replacement during zone substation renewal to renewing our older numeric protection schemes on zone substations that are mid-life.

We have replaced a significant number of electromechanical relays, and we are currently replacing the remaining ones as part of our substation renewal programme. Additionally, we are upgrading static and first-generation numerical relays that have reached the end of their operational life. 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 errors), and improved reliability performance.

We have forecast protection renewal Capex of approximately $11.2 million during the planning period. This expenditure excludes protection replaced under zone substation projects.

Figure 11-69: Capex forecast protection by region (RY24 constant, $m)



11.9.3. DC systems fleet

DC systems provide a reliable and efficient power supply to vital elements within our zone substations and our assets at GXPs. They ensure continued operation of these devices when AC supply is lost. 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 and communications.

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, 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 zone substations have dedicated 24/48 VDC supplies specifically allocated for communication purposes. This includes sites exclusively designated for communication. Table 11-44 summarises our population of DC systems.

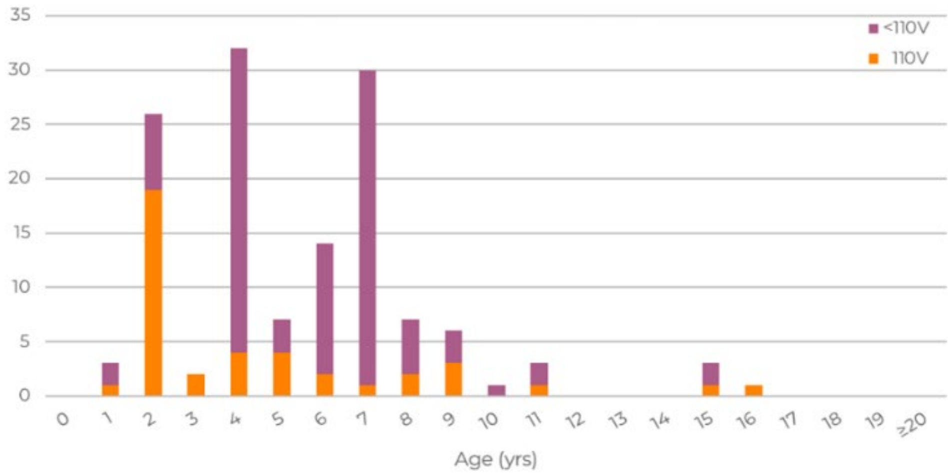
Table 11-44: DC system asset population by voltage and sub-network

Voltage level	Dunedin	Central Otago & Wānaka	Queenstown	Total
110 V	24	13	7	44
48 V	3	5	2	10
12/24 V	15	44	23	82
Total	**42**	**62**	**32**	**136**

ASSET AGE

Figure 11-70 gives the age profile of our battery banks. The majority of our battery banks are below their expected life of 8–10 years, while the remaining are awaiting planned zone substation projects.

Figure 11-70: Battery bank 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.

ASSET PERFORMANCE AND RISK

Table 11-45 sets out the key risks identified in relation to our DC systems.

Table 11-45: 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 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 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 entire bank. If a charger is tested and found to be faulty, it is replaced.
- **Age:** Batteries have an expected life of 8-10 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 with every second battery replacement 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.

Longer-term, at N−1 battery bank sites, we may consider staggering replacements. 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.

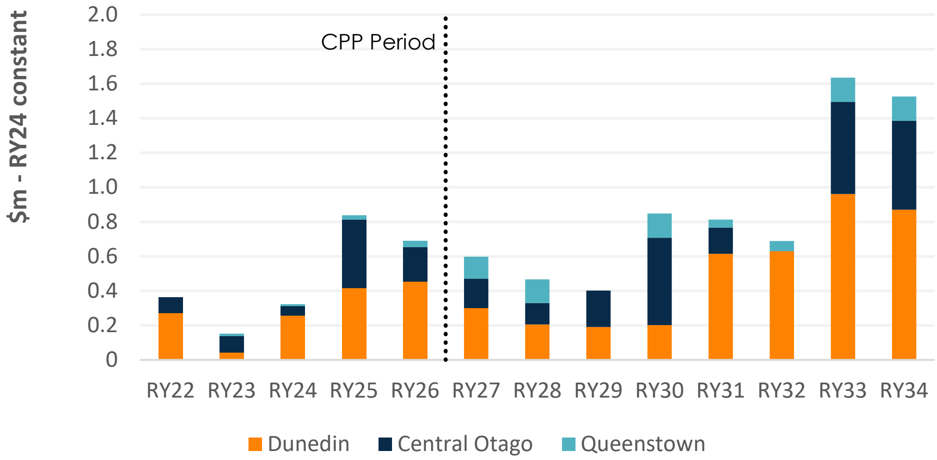
FORECAST CAPEX EXPENDITURE

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 volume 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 $4.8 million during the planning period. This expenditure excludes DC systems replaced under zone substation projects.

Figure 11-71: Capex forecast DC systems by region (RY24 constant, $,000s)



11.9.4. Metering fleet

Our metering fleet includes check metering at GXPs and a small number of power quality units at some zone substations. Check meters are installed at our GXPs to confirm and authenticate the precision of the Transpower revenue meter and serve as a quality control measure, independently ensuring the precision of Transpower revenue meter. It also functions as a backup metering system in instances where Transpower meters are out of service.

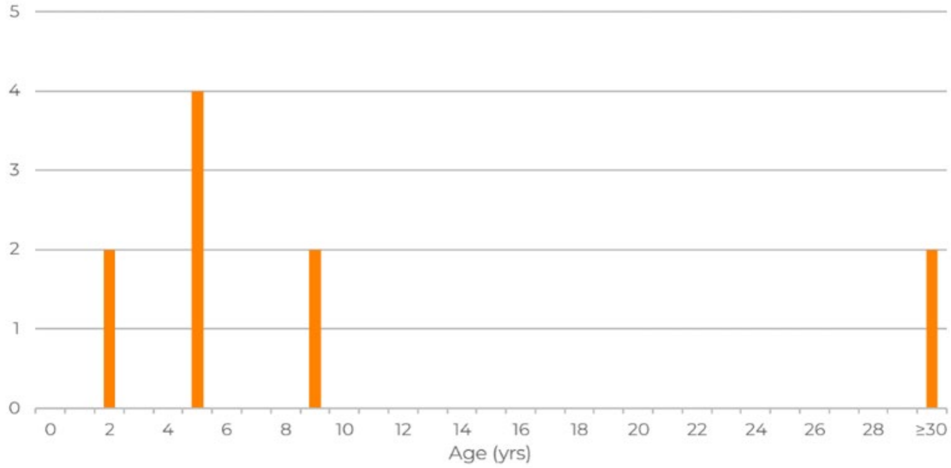
We have replaced older and unsupported meters at three of our GXPs, but we still have legacy check meters in the Central Otago sub-network. Modern GXP check meters are able to communicate via a modern protocol (i.e. DNP3) and provide remote access functionality. Our meters can record additional parameters, such as peak and average MVA, and power factor.

We have installed 10 power quality meters on the 11 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, their high precision and accuracy enable our planning team to make well-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 threshold limits.

ASSET AGE

We have 10 check meters across our network. All but two are currently nine years old or less. Two are near end-of-life, one of which is to be replaced in RY24. Our power quality meters are all less than seven years old. The life expectancy of a modern numerical meter is 25 years.

Figure 11-72: Metering age profile



CONDITION AND HEALTH

We are not experiencing any condition or performance issues with our metering fleet.

ASSET PERFORMANCE AND RISK

Table 11-46 sets out the key risks identified in relation to our metering fleet and their associated mitigations.

Table 11-46: 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 ours 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 other electromechanical or electronic devices.

FORECAST CAPEX EXPENDITURE

No renewal expenditure is planned under this portfolio during the planning period.

11.9.5. Communications 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 manage 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, 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 with the migration of 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 older technology TDM point-to-point radios, which are specifically used to provision teleprotection services but also carry SCADA and other site communications. We also make extensive use of public 4G networks for remote connectivity and redundancy.

All Aurora Energy sites are connected and operate over a private Wide Area Network (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 in the Aroura Energy Data centres thereby creating connectivity between the Control Centre and the RTUs in the field.

Many of the communication systems components are IP-capable and are remotely monitorable. 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 11-47: Communications component populations by type

Asset	Terminals
UHF point to multipoint and 4G routers	110
Broadband IP microwave radio links	24
TDM UHF and microwave radio links	24
Network routers/switches	88

Table 11-48: 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.

The entire Communications System fleet is less than eight years old. This is because the entire Aurora Energy private radio network was replaced and enlarged between 2016 and 2019. New 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 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 the cables are still functionally in a good condition. However, an increase in cable attenuation (losses) on some cables has been noted most likely because of corrosion due to moisture ingress. In general, fibre optic cables in Aurora Energy are still relatively new and are not exhibiting any health issues.

The telecommunication systems 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 in order to pre-empt any issues.

It has been identified that some of our older IP routers are no longer fit for purpose and are being actively replaced over the next three years.

ASSET PERFORMANCE AND RISK

In general, the copper cable network is performing well with only increases in attenuation/losses having been noted. There is a risk that the cables degrade to a point of failure that could result in loss of a protection function, however this is mitigated through having independent protection schemes on subtransmission circuits.

The performance has been very good for the fibre optic network and no risks have been identified.

In general, the radio and IP router network Is performing well and no significant risk with regards 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. Copper cables are being decommissioned when they are no longer required as services are being 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 or 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 which are affected by a supplier notification of end of support will be replaced.

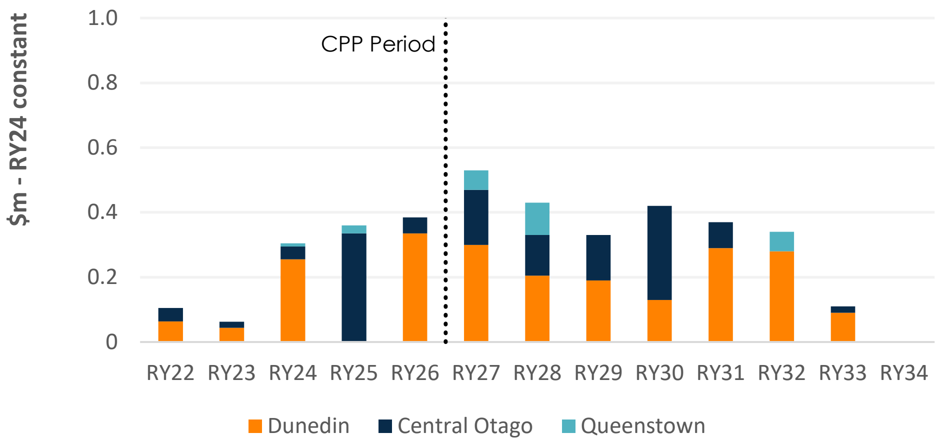
DISPOSAL

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 11-73: Capex forecast communications by region (RY24 constant, $,000s)



11.10. CRITICAL SPARES

To assist maintenance activities, we hold critical spares of certain assets. In general, 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 cables 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.

More information will be provided in future AMPs once we have completed the critical spares strategy.

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 a mix of cloud and on-premise solutions to ensure a sustainable, secure technology foundation during the CPP period.

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.

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 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 information and data is trusted 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	Automate Maintenance & Capital Workflows	Understanding asset condition in (near) real time to predict and reduce/prevent asset failure and optimise life expectancy of assets Investigate use of drone/HD/thermographics to detect asset deterioration invisible to human eye or standard maintenance routines
Automation of tedious or dangerous work	Advanced analytics	Use of AI to process large data sets to identify emerging trends or constraints (e.g. power flow modelling, identifying fault hotspots etc) Use of sensors 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 & IoT	Smart Meter Data providing early visibility of real time consumer supply and/or voltage quality to enable faster response times and better data to triage issues on the network Use AI to identify / monitor EV and PV uptake in the network Use of data feeds to enable Real time operational control capabilities and proactively respond to Load and Demand Forecasting
Optimise business practices	Resource and Capability	Managing Cyber Threats - Use of AI process in real time for 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	Use of sensors on distribution transformers to understand and trouble shoot voltage quality issues before they become problematic Investigate robotics use to respond to (online) consumer service queries

12.1.1. ICT assets and service plans

This section describes how we manage assets and services across our ICT portfolios. Each portfolio plan covers the strategic direction, lifecycle needs, and the forecast expenditure required for the current CPP period and DPP4.

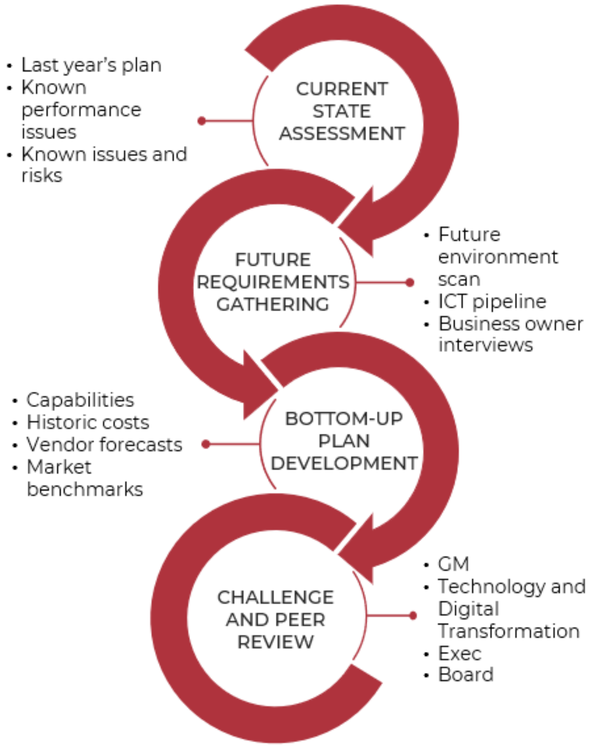
Our key philosophy in managing our ICT assets and services is to achieve business outcomes, investing in the ICT assets as necessary to support them and replacing only at end-of-life or when obsolete.

We monitor all ICT systems continuously for performance and capacity and report our overall performance monthly. Key performance measurements for our major systems including availability, service outages (number and duration) and service level achievement are tracked and monitored.

As our consumers become prosumers and the use of our network becomes more dynamic and bidirectional, we must make new capabilities, data and insights available to the wider business, our consumers, and our business partners. To avoid stagnating, we monitor other EDBs and emerging tech.

Our ICT pipeline process constantly captures new requirements from the business. Figure 12-1 outlines our process for ICT requirements capture, assessment and planning.

Figure 12-1: ICT requirements capture, assessment and planning process



We are confident that this process results in an evidence-based plan that is prioritised against consumer needs and benefits and is efficiently costed.

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 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 the 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	Support ICT services and infrastructure (servers, operating systems, data centres, storage, backup), identity and access management, telecommunications, network, security, end-user device, and business continuity and disaster recovery capability

ICT solutions change frequently as an increasingly large number of our devices and processes depend on digital technologies and communication. Most of our capitalised ICT assets have a depreciation life of less than five years, reflecting the rapid rate of innovation and change in the technology industry.

ASSET MANAGEMENT

Asset management services relate to capabilities that support our core activities including asset inspections, work planning, issuance, job management and recording, as well as long-term asset management strategy.

A core focus for the CPP period has been commissioning new tools for work and job management, and to improve the collection of, and quality and accuracy of, asset data. This is needed to assist in lifting capability in risk and condition assessment and improving our asset management maturity – allowing us to scope, select and implement new work, job and works management tools to improve the efficiency of our field work and the quality of the data we maintain about our assets. Ultimately this will improve our ability to plan how and when to maintain and replace assets in order to efficiently meet the evolving needs of consumers.

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 to support capital and operations work planning and delivery Complete the development of an automated process to create and refresh our network power flow model. Further enhancements to 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 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 systems used – GIS, Asset Management, analytics toolsets. Adding/improving capability to support external data sets

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.

OUTAGE MANAGEMENT SYSTEM (OMS)

The OMS enables us to plan and communicate outage restorations predictably, efficiently and safely by modelling the topology of the network and integrating with our other consumer management tools. As a component of 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 allows us to carry out detailed analysis and investigation of network performance, operational trends and incidents.

Our two areas of focus for the CPP period have been to upgrade our SCADA and complete the implementation of an OMS. This will enable us to manage and communicate all outage incidents on our network and thereby manage outages more efficiently and provide up-to-date information to consumers, by feeding data directly to our website and call centre.

In DPP4 we will use these foundations to support the secure and efficient operation of the power system as distributed energy resources make it more bidirectional and dynamic: The SCADA upgrade will give our network controllers better visibility of an ability to manage devices at the edge of our network, to ensure power quality and reliability is maintained for all consumers. The OMS will automate our restoration of supply after unplanned outages, allowing us to restore power faster and provide consumers with more accurate notifications about how long they will be without power.

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 allowing improved cyber security and external support. Improved management, consumer communication and reporting of planned and unplanned outages on the network. Review 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 cloud services. This may drive a major lifecycle replacement

CONSUMER AND COMMERCIAL

Our consumer and commercial portfolio includes billing, case management and regulatory compliance services. Our focus for the CPP period has been to commission new case management capability in parallel with exploiting the ability of our new operational technology platforms to offer improved notifications to consumers around outages and likely restoration times.

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 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 priority during the CPP period has been to consolidate our legacy Financial Management system as it approaches the end of vendor support. We will focus DPP4 on migrating to the most efficient future options for these tools.

Table 12-6: Corporate investment focus

Horizon	Investment Focus
CPP	Implementation of a business system integration platform to enable systems to support end-to-end business processes and ensuring one source of data Completion of separating Aurora Energy infrastructure and services from Delta Optimising our communications network by improving redundancy and ensuring a higher level of resilience
DPP4	Reviewing core financial systems and employee management and payroll systems Enhancing new financial tools

ENTERPRISE TECHNOLOGY & INFRASTRUCTURE

This covers the enabling technology and generic technology frameworks and platforms that allow us to provide mobile access to business services, integrate standalone data sources and analyse information as well as support the processing, storage and exchange of digital information around the company.

In 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 to allow/enable advanced analytics, supported by artificial intelligence, 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 artificial intelligence to drive enhanced analytics

12.2. EXPENDITURE OVERVIEW

Consistent with inflationary pressures in the wider economy, current actual costs are exceeding 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
- **Licencing:** Our two largest suppliers, Microsoft and SAP, have both increased their annual licence fees by more than 5% over the last year

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. In the last year, our cyber security measures have cost over $400,000 more than we expected at the time of preparing the CPP.
- **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 are now incurring the costs of acquiring, storing, managing, and analysing LV meter data to enable us to do this. The related costs are expected to be in the order of $6.5 million over the next 10 years.

We have updated our forecasts for RY24 and 25 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.

Our CPP proposal was focused on consolidating our ICT capabilities to a point where we are able to support our business with timely and reliable information from a consistent single source. Our plans for DPP4 build on that foundation providing for the new digital capabilities that will be 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 and 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 taking into account the efficiencies we expect to gain from greater expenditure on digitisation and improved systems and processes.

A key focus area for Aurora Energy is the automation of asset management workflow processes across the business and the implementation of state-of-the-art platforms to support this core function. To make the most of new systems we must develop our capability and invest in our people. We are accelerating our capability through the implementation of automated performance management and continued investment in our managers through 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 & Planning

The Asset Management and Planning (AM&P) group is 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. This group is also charged with the preparation of AM&P work programmes and network engineering designs.

There are four teams in this group:

- Strategy and Reliability Performance
- Asset Lifecycle
- Network Planning
- Engineering

13.1.3. Operations & Network Performance

The Operations and Network Performance group is responsible for the daily operation of the network, which encompasses control room functions, network access permissions, switching, public safety management and operational planning for new and emerging technologies

There are three teams in this group:

- Network Operations Management
- Operational Information and Fault Follow-up
- Network Performance and Operational Technology

13.1.4. Works Programming & Delivery

Our Works Programming and Delivery group is responsible for work programming and the scheduling of work across the network, 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.

There are five teams in this group:

- Works Delivery
- Contractor Management
- Network Procurement
- Programming and Scheduling
- Contractor Health and Safety

13.1.5. Business Process Optimisation

Our Business Process Optimisation group is a newly formed group responsible for the delivery of digitisation and process improvements to better position Aurora Energy for the changing future. This group also oversees new connections to the network and works with key large connection consumers across our sub-networks.

There are two teams in the group:

- Business Process and Change
- Customer Initiated Works

13.1.6. Quality Assurance

Quality assurance processes are embedded within our Works Programming and Delivery team.

Appropriate quality assurance processes and resources must be in place to ensure that our escalated level of planned works for the CPP Period and beyond are delivered to all applicable industry standards.

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.

To improve our works quality assurance, we have introduced an internal quality assurance standard that defines how constructed works for review are identified and completed, and how review results are recorded. Quality assurance records are monitored through a monthly *constructed works non-conformance reporting and escalation process*, with feedback provided directly to field service providers. We plan to further develop quality assurance metrics and reporting so we can better manage field service provider performance and resolution timeframes.

We also plan to extend the scope of our quality assurance review process to include inspection and maintenance tasks, connection services, vegetation management, and zone substation works. We will review the required resourcing and internal development to meet the requirements of our upgraded 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 Assurance & Commercial

The Finance Risk Assurance and Commercial group manages our financial management, regulatory reporting and commercial functions. These functions include financial budgeting and forecasting, regulatory disclosures and financial reporting processes, internal and external audit arrangements, pricing methodologies, and commercial contracts. This team also oversees our enterprise risk management framework and manages external relationships with our regulators.

There are four teams in the group:

- Financial Planning and Analysis
- Accounting and Finance
- Risk Assurance and Regulatory Compliance
- Commercial Planning & Pricing

13.2.2. People, Customer & Sustainability

Our People, Customer and Sustainability group is responsible for managing stakeholder and consumer interfaces and reflecting these in stakeholder engagement and communications plans. The group ensures that stakeholders, including the community and consumers, have opportunities to provide feedback and input into future network planned expenditure. The group is also responsible for the development, design and implementation of people-related frameworks, policies and practices and the health, safety and wellbeing of Aurora Energy staff and oversight of organisational sustainability plans.

There are two teams in this group:

- People and Culture
- Customer and Engagement

13.2.3. Digital Transformation

Our Digital Transformation group is responsible for managing Information and Communication Technology (ICT) systems and data governance strategies on behalf of Aurora Energy, as well as our overall digital transformation roadmap which links directly to optimising business processes and preparing for the future. The team is also responsible for delivering ICT services and managing our operational response and mitigation strategies for cyber security threats.

There are three teams in this group:

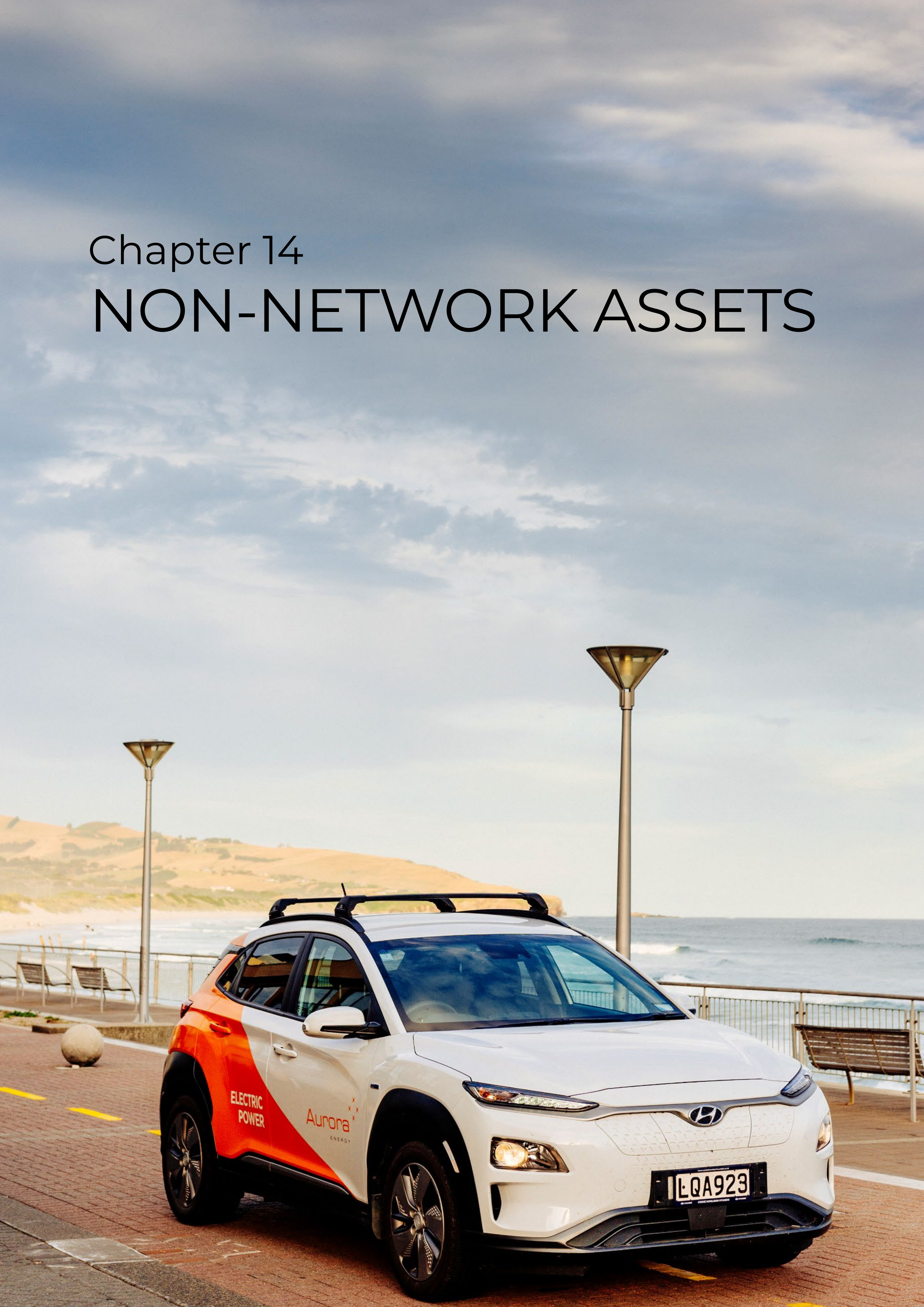
- Information and Intelligence
- Digital Delivery
- ICT Services

These functions all support our electricity asset management activities. Opex related to these activities is classified as non-network Opex. Below we discuss some of the key drivers for this expenditure over the planning period:

- **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 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.

Chapter 14

NON-NETWORK ASSETS



14.1. NON-NETWORK ASSETS

Broadly speaking, our non-network assets comprise of 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 that 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 that this team is able to 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 is generally undertaken by 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 for 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 by 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 RY24.

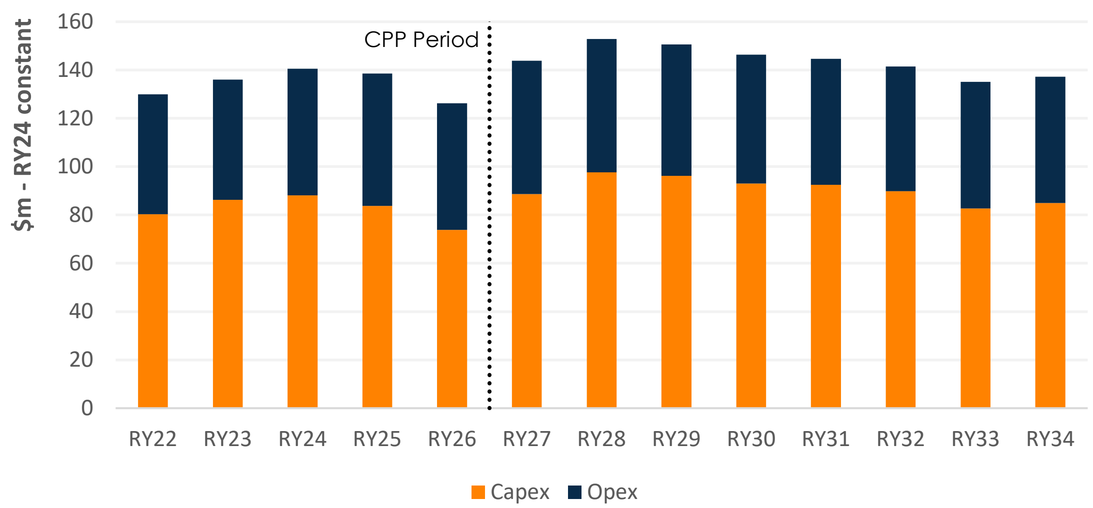
This chapter sets out our expenditure forecasts over the AMP period. It provides further commentary and context for our forecasts, including key assumptions and discusses our cost estimation methodology and how this has been used to develop our forecasts.

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 the development of 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 to RY34. Total expenditure for the 10-year period to RY34 is $1.4 billion. All financial values are expressed in $RY24 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 in maintaining, renewing, and operating our distribution network efficiently, offering transparency and commercial prudence.

Distributed Generation: Our network incorporates distributed generation, such as hydro and wind, which collectively contribute 143 MW, representing 46% of system maximum demand. 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 solarZero exemplifies our commitment to smoothening demand peaks and reducing asset criticality.

DECISION-MAKING AND INVESTMENT OPTIMISATION

Strategic Framework: Our asset management strategy and framework, aligned with ISO 55001 standards, guide all spending and operational decisions, ensuring continuous improvement and effective risk management.

ICT Investments: We harness ICT advancements for asset management, like the EAMS, 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 developed what we consider to be a 'minimum viable plan' with no contingency. We have used the latest available asset condition inspection information to reduce expenditure in asset renewals to make way for high priority growth related projects. In some cases, we have also applied engineering judgement where we believe future inspection information is likely to show more favourable asset condition than the current data suggests. We will review and flex our plan annually as new information becomes available.

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. There have been 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/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, network configuration changes (for example, splitting feeders) will be made to improve reliability. We propose a targeted programme, with $10 million across the 10-year planning period.

Our resiliency programme will include the provision of additional spares and associated storage facilities, back-up 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 that we meet our objective to reduce 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. 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.

Cost escalation between AMP2023 and AMP2024 is the predominant driver of our increased forecasts. Analysis of our CPP annual delivery report unit rates and insights from our major field service agreement (FSA) tender round have concluded that a 10–15% increase reflects current as-built costs.

Furthermore, as part of our CPP improvement plan we have completed a cost estimation improvement initiative to better estimate the cost of our major zone substation projects for both renewals and growth expenditure drivers.

We have had a track record of underestimating the cost of major projects, and the new process better captures the scope of projects and utilises a refreshed unit rate schedule.

Figure 15-2: 10-year Capex forecast by sub-network, Total ($m)

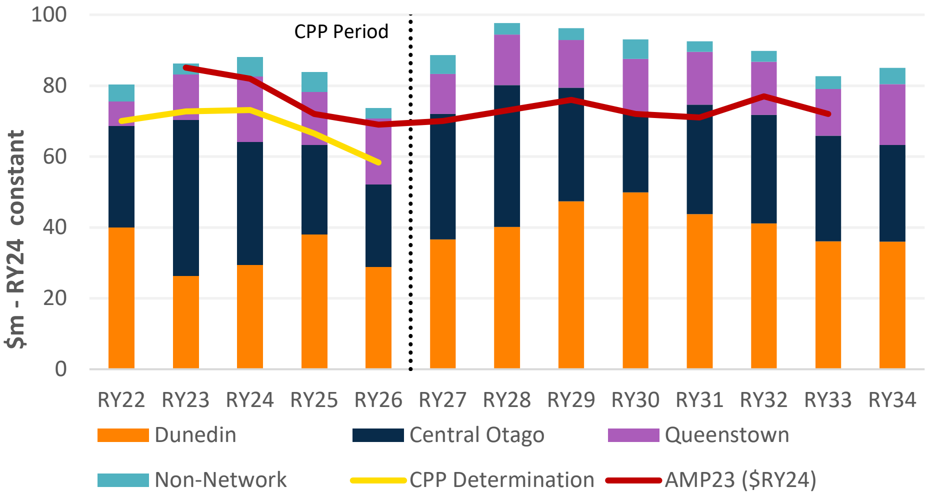


Table 15-1 shows our total forecast capital expenditure during the AMP planning period.

Table 15-1: 10-year Capex forecast, Total ($m)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Asset Replacement and Renewals	56.3	40.8	46.0	51.8	53.8	56.5	52.1	49.0	44.2	43.7
System Growth	11.0	18.8	25.4	30.5	25.8	16.8	23.7	24.5	22.1	23.9
Reliability, Safety and Environment	0.5	0.6	2.0	3.1	4.3	5.2	4.7	4.2	3.7	3.7
Customer Connections and Asset Relocations	10.5	10.6	9.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Non-network Capex	5.5	3.0	5.3	3.2	3.2	5.6	3.0	3.1	3.6	4.5
Totals	**83.8**	**73.8**	**88.7**	**97.6**	**96.2**	**93.1**	**92.5**	**89.8**	**82.7**	**85.0**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Asset Replacement and Renewals	31.0	24.1	31.1	34.0	38.0	40.9	34.2	30.4	25.4	25.9
System Growth	2.1	0.2	0.3	1.6	4.5	3.9	4.5	5.9	5.9	5.2
Reliability, Safety and Environment	0.1	0.1	0.5	0.7	1.0	1.3	1.2	1.1	1.0	1.0
Customer Connections and Asset Relocations	4.8	4.5	4.6	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Non-network Capex	3.3	1.8	3.2	1.9	2.0	3.4	1.8	1.8	2.2	2.8
Totals	**41.3**	**30.6**	**39.8**	**42.1**	**49.3**	**53.3**	**45.6**	**43.0**	**38.3**	**38.8**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Asset Replacement and Renewals	18.5	10.2	9.9	12.9	11.3	11.0	11.2	10.4	13.1	12.9
System Growth	3.0	11.5	20.2	21.9	15.2	5.9	13.9	14.6	11.3	9.0
Reliability, Safety and Environment	0.4	0.1	0.6	1.0	1.3	1.6	1.5	1.4	1.2	1.2
Customer Connections and Asset Relocations	3.5	1.5	4.6	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Non-network Capex	1.3	0.7	1.3	0.7	0.8	1.4	0.7	0.7	0.9	1.1
Totals	**26.7**	**24.0**	**36.7**	**40.8**	**32.9**	**24.1**	**31.6**	**31.3**	**30.6**	**28.4**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Asset Replacement and Renewals	6.8	6.5	5.0	4.8	4.4	4.6	6.6	8.2	5.7	4.8
System Growth	5.9	7.2	4.8	7.0	6.0	6.9	5.2	4.0	4.9	9.7
Reliability, Safety and Environment	0.1	0.4	0.9	1.4	2.0	2.3	2.0	1.8	1.6	1.6
Customer Connections and Asset Relocations	2.2	4.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Non-network Capex	0.9	0.5	0.8	0.5	0.5	0.9	0.5	0.5	0.6	0.7
Totals	**15.8**	**19.2**	**12.2**	**14.8**	**14.0**	**15.7**	**15.3**	**15.5**	**13.8**	**17.8**

CAPEX FORECAST VARIANCE FROM PREVIOUS AMP

Cost escalation between AMP2023 and AMP2024 is the predominant driver of our increased forecasts. Analysis of our CPP annual delivery report unit rates and insights from our major field service agreement (FSA) tender round have concluded that a 10–15% increase reflects current as-built costs.

Furthermore, as part of our CPP improvement plan we have completed a cost estimation improvement initiative to better estimate the cost of our major zone substation projects for both renewals and growth expenditure drivers. We have had a track record of underestimating the cost of major projects and the new process better captures the scope of projects and utilises a refreshed 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, a new 66 kV line in the Upper Clutha more than doubles our 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.

A tripling of system growth expenditure is required to strengthen the subtransmission and 11 kV networks to meet strong consumer connection activity – the upper Clutha subtransmission upgrade project causes more than half of this increase.

To help manage affordability for consumers we have reduced the forecast levels of renewal expenditure over the next 10 years. This extends the period of safety risk backlog slightly but, in the context of strong growth, it was deemed necessary to help ensure our plan is deliverable and affordable.

For AMP2024, we have considered increasing need for further investment in reliability and resiliency over the next 10 years.

Overall, these variances result in an increase in capital expenditure of approximately 23% over the reporting period.

Figure 15-3: AMP24 Capex forecast variance from AMP23 forecast

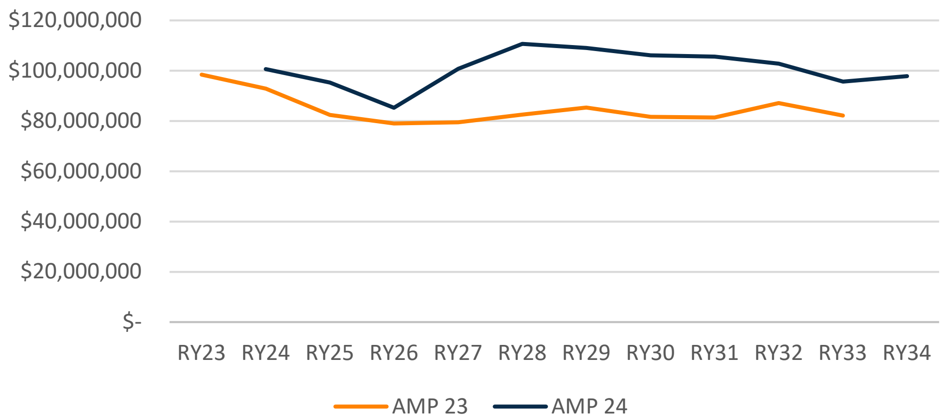


Table 15-5: AMP24 Capex forecast variance from AMP23 forecast ($m)

AMP24	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33
Consumer Connection	0.59	6.55	6.84	6.47	6.09	5.70	5.30	4.88	4.45	4.01
System Growth	8.66	1.74	11.61	18.77	24.12	17.78	9.22	16.36	11.17	5.64
Asset Replacement and Renewal	-4.80	4.14	-9.87	-5.40	-4.83	-3.78	2.67	-1.09	-1.81	0.07
Asset Relocations	0.19	-2.16	-2.16	-0.88	-0.88	-0.88	-0.88	-0.88	-0.88	-0.88
Reliability, Safety and Environment	0.07	-0.08	0.16	1.28	2.38	3.58	4.48	3.98	3.48	2.98
Non-network Assets	3.09	2.77	-0.33	1.10	1.31	1.29	3.69	0.90	-0.72	1.72
Totals	**7.80**	**12.96**	**6.25**	**21.33**	**28.18**	**23.69**	**24.48**	**24.16**	**15.68**	**13.54**

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 from AMP23 to AMP24 Opex forecasts. 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 8% from our previous AMP.

15.3.1. 10-year Opex forecast

The figure and tables that follow are expressed in $RY24 Constant.

Figure 15-4: 10-year Opex forecast by sub-network, Total ($m)

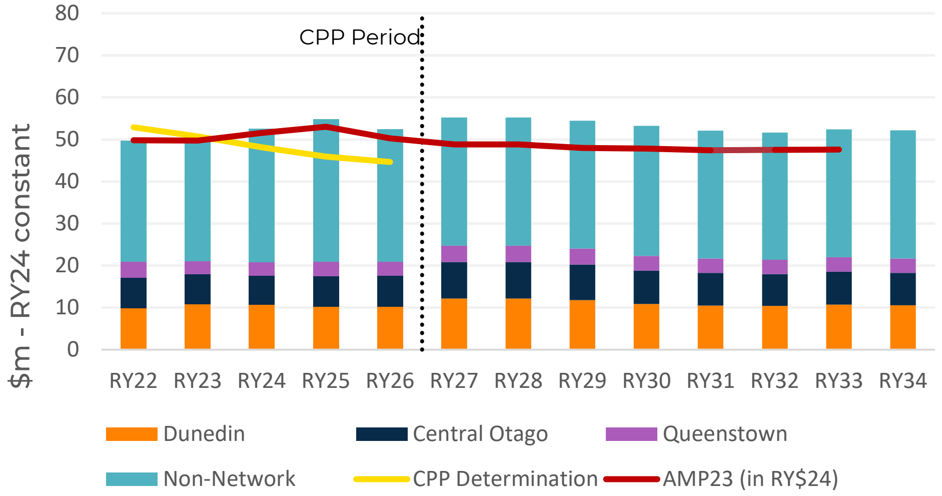


Table 15-6 shows our total network maintenance Opex forecast during the AMP planning period.

Table 15-6: 10-year network maintenance Opex forecast, Total ($m)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Preventive Maintenance	7.8	7.7	10.7	10.7	10.5	10.3	10.1	9.7	10.3	9.8
Corrective Maintenance	5.6	5.8	6.6	6.6	6.0	4.6	4.0	4.1	4.1	4.2
Reactive Maintenance	3.6	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.8	3.8
Vegetation Management	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SONS	16.6	15.4	14.8	14.8	14.8	15.1	14.7	14.5	14.6	14.6
Business Support	17.3	16.0	15.7	15.7	15.6	15.8	15.8	15.7	15.8	15.8
Totals	**54.8**	**52.4**	**55.3**	**55.3**	**54.4**	**53.3**	**52.2**	**51.6**	**52.5**	**52.1**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Preventive Maintenance	3.8	3.7	5.2	5.2	5.1	5.0	4.9	4.7	5.0	4.8
Corrective Maintenance	3.0	3.2	3.6	3.6	3.3	2.5	2.2	2.2	2.3	2.3
Reactive Maintenance	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0
Vegetation Management	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Totals	**10.2**	**10.3**	**12.2**	**12.2**	**11.8**	**10.9**	**10.5**	**10.3**	**10.8**	**10.6**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Preventive Maintenance	3.1	3.1	4.2	4.3	4.2	4.1	4.0	3.8	4.1	3.9
Corrective Maintenance	1.7	1.8	2.0	2.0	1.8	1.4	1.2	1.3	1.3	1.3
Reactive Maintenance	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2
Vegetation Management	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Totals	**7.2**	**7.3**	**8.6**	**8.7**	**8.4**	**7.9**	**7.7**	**7.6**	**7.9**	**7.7**

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)

AMP24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34
Preventive Maintenance	0.9	0.9	1.2	1.2	1.2	1.2	1.2	1.1	1.2	1.1
Corrective Maintenance	0.8	0.9	1.0	1.0	0.9	0.7	0.6	0.6	0.6	0.6
Reactive Maintenance	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Vegetation Management	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Totals	**3.4**	**3.4**	**3.9**	**3.9**	**3.8**	**3.**	**3.4**	**3.4**	**3.5**	**3.4**

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 detailed, by Opex category, model inputs are described in **Chapter 11**. The following is a summary of the key factors contributing to the overall uplift in forecast:

- Introduction of new inspection programmes and enhancement of existing inspection programmes
- Expanding on the use of advanced inspection technology such as thermal & acoustics and Lidar surveys
- Increased defect find rate due to a new and enhanced inspection programmes
- Consumer pole inspection and remediation
- Deferred maintenance and rollover
- Trend assumption of enhancement of network condition and performance
- Application of the Commerce Commission 2019 trend factor for change in network scale of 1.13% per annum to our forecast

In addition to network Opex, the combined impact of recent inflationary pressures, the need to keep pace with growth and technology advancements and the transition towards 'as a service' operating models, is such that we are now forecasting to spend in excess of our current non-network Opex allowances, for the remainder of the CPP period and beyond.

Figure 15-5 and **Table 15-7** are provided to quantify the costs associated with the adjustments.

Figure 15-5: AMP24 Opex forecast variance from AMP23 forecast

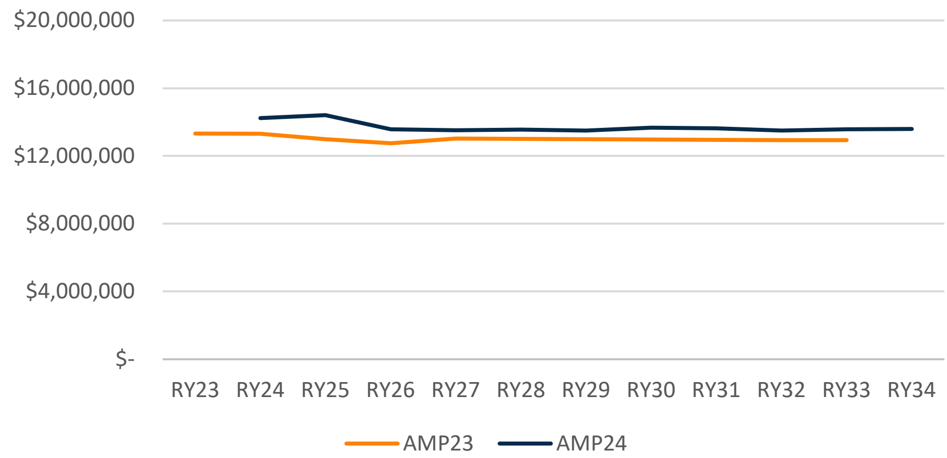


Table 15-7: AMP24 Opex forecast variance from AMP23 forecast ($m)

AMP24	RY24	RY25	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33
Service Interruptions and Emergencies	0.15	0.39	0.38	0.51	0.50	0.50	0.50	0.51	0.51	0.52
Vegetation Management	0.17	0.12	0.15	0.17	0.16	0.15	0.17	0.16	0.15	0.17
Routine and Corrective Maintenance and Inspection	0.54	0.72	1.28	5.65	5.73	5.56	4.04	3.76	3.29	3.83
SONS										
SONS	2.27	3.34	2.75	2.41	2.45	2.42	2.61	2.59	2.48	2.55
Network Evolution	-0.26	0.05	0.20	0.33	0.32	0.58	0.57	0.18	0.19	0.20
CPP Application Costs	0.00	-0.33	0.04	0.06	0.00	0.00	0.00	0.00	0.00	0.00
Upper Clutha DER Solutions	-0.39	-0.69	-0.91	-0.92	-0.92	-0.92	-0.92	-0.92	-0.91	-0.91
Business Support										
People	0.72	0.92	0.55	0.34	0.39	0.35	0.48	0.44	0.40	0.42
CPP Application Costs	0.00	-0.33	0.04	0.06	0.00	0.00	0.00	0.00	0.00	0.00
ICT Opex	-0.23	-0.42	-0.33	-0.16	-0.14	-0.11	-0.08	-0.05	-0.01	0.02
Premises and Plant	0.01	0.02	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00
Administration and Governance	0.18	0.28	0.15	0.05	0.07	0.05	0.10	0.08	0.06	0.07

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.

We considered the drivers in Dunedin and Central Otago, which can be different. We see a strong uptake of electric vehicles in Dunedin, and a strong uptake of solar generation in Central Otago. The Dunedin sub-network is a dense metropolitan network, with a meshed/interconnected architecture and an ability to transfer load to neighbouring substations and feeders. Large parts of Central Otago are isolated with limited or no ability to transfer load. Central Otago growth is significantly higher than Dunedin, and small increases in demand in Central Otago can trigger network reinforcement projects.

Our revised forecasts indicate an urgent need for additional capacity if we are to avoid the risk of winter shutdowns in a cold environment. Key stakeholders such as the Queenstown Lakes District Council have clearly articulated their expectations of Aurora Energy keeping pace with growth in the region and electricity as an enabler to achieving their zero carbon tourism goals. In addition to the Upper Clutha upgrade work, we have a number of smaller projects related to meeting capacity requirements, or compliance with our security of supply guideline.

Table 15-8 highlights major projects in the sub-networks for the next regulatory year.

Table 15-8: Annual work plan RY25

Major projects	Dunedin	Central Otago & Wānaka	Queenstown	Total
Dunedin Projects				
Smith Street to Willowbank 33 kV intertie	1.822	—	—	1.822
Smith Street 11 kV Switchboard Replacement	3.459	—	—	3.459
Green Island Substation Rebuild	5.572	—	—	5.572
Central Otago & Wānaka Projects				

Major projects	Dunedin	Central Otago & Wānaka	Queenstown	Total
New Upper Clutha 66 kV line	—	0.526	—	0526
Alexandra new feeder cable	—	0.395	—	0.395
Riverbank Road - Riverbank Zone Substation (Design)	—	0.580	—	0.580
Riverbank 11 kV feeders Stage 1	—	0.146	—	0.146
Upper Clutha New Autotransformer	—	1.283	—	1.283
Alexandra 33 kV and 11 kV Outdoor-Indoor Conversion	—	6.254	—	6.254
Queenstown Projects				
Malaghans (New Dalefield) Zone Substation	—	—	4.553	4.553
Frankton Zone Substation Transformer Replacement	—	—	1.269	1.269
Queenstown – 33 kV & 11 kV Protection and Bus Upgrade	—	—	2.252	2.252
All Sub-networks				
LV Reinforcement	0.171	0.171	0.171	0.513
Totals	**$11.024**	**$9.355**	**$8.245**	**$28.624**

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 the accuracy related to uncertainty 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 ongoing effort has yet to deliver concrete benefits that we can confidently claim and celebrate.

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, which require a range of factors to be considered, 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 AMP23 and AMP24 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 (RY24) forecasts to produce the nominal dollar forecasts for the Information Disclosure schedules in Appendix B.

The consultancy advice we received included commentary outlining a higher level of uncertainty in the escalation forecasts due to recent and ongoing global events. Recent price increases from our suppliers have been incorporated into the RY24 constant dollar assumptions, where we have the finalised information 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 that 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 that 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 projects are considered complex, high risk, 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. We have had a track record of underestimating the cost of major projects and the new process better captures the scope of projects and utilises refreshed unit rate schedule.

15.5.4. Trending

We have used a trend-based approach to forecast part of our expenditure. The approach is used by many utilities for forecasting recurring expenditure. This 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 that is representative of recurring expenditure we expect in future years. If there are significant events (for example, major storms) 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 load 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 that 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 composite of potential efficiency sources that are discussed below:

- **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, EAMS) 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 recognises the importance of ensuring we have competency growth plans in place to match our development plans and our asset management outlook. Our competency and training development plan supports the business, developing a target area in our AMMAT assessment. Further detail on our Competency and Training Development is provided in Section 6.7.

The retention and attraction of skills that are critical to our business, as well as the investment in and development of our people, are a key strategic focus for our business. Aurora Energy has initiated a People and Culture Plan, which is currently being advanced.

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 which 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.

With current field service contracting arrangements expiring at the end of RY24, we have recently concluded extensive competitive tender processes to establish new contracting agreements for both field services and vegetation services. From 1 April 2024, the following key Field Service Providers will be operating on the Aurora Energy network:

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

In addition to this, Delta and Asplundh will be Vegetation Service Providers performing vegetation maintenance on the Aurora Energy network.

The field services and vegetation services procurement methodology was developed and managed utilising specialist external legal and procurement resources to ensure a fair and transparent process that demonstrated commercial market outcomes and delivered contracting arrangements that satisfied regulatory requirements. The key outcome of the process was to ensure that suitable capability and capacity exists within the chosen network contractors to safely operate and maintain the network in both the short- and longer-term.

In addition to field capability, our Engineering Services Panel provides us 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 neighbouring 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 high confidence in delivering our DPP4 and 10-year period plan.

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 a connection application is made to Aurora Energy by the Authorised Network Contractor or Inspector engaged in the pursuit of a new or altered connection. 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 then be arranged to go ahead.

Once a job is complete and the inspector has filled out the livening report imbedded in the portal application, Aurora Energy's database is updated, along with the Electricity Authority Registry (when 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 in the contractor's realm. 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 the 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, 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 discussed in Chapter 15, the selected contractors for tender work is generally greater than the Field Service Providers, providing competitive tension in the pricing of major projects.

Our 10-year plan is reviewed every year, taking account of changes in demand, consumer preferences and works coordination (see below). Generally, 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 required through DFA and our Board where necessary.

Over the CPP Period, we aim to improve our approach to cost-estimation. See Chapter 9 for our cost estimation improvement plan, as well as other key initiatives that are being undertaken. Our service delivery model seeks to ensure:

- A works delivery approach with clear accountability of core business functions
- Integrated works programming, scheduling, and governance capability to ensure a smooth and well-coordinated flow of work to the field
- 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 delivery teams takes place. This process 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. 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 that 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 may be included as part of tendering documents.

Quality control over construction and commissioning works is critical to ensure that our assets operate effectively and safely over their intended lives. Quality control ensures that projects are constructed in a way that enables design intentions and, therefore, limiting premature reactive maintenance – as per 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 are to ensure compliance with our standards, to ensure high standards of work, to ensure the required scope of work is being delivered, and to 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:

- Confirming the asset information systems have been updated with as-built information
- Capitalisation of assets within the financial systems
- Archiving relevant documentation
- Analysing 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)
- Undertaking a review of lessons learned during the project, particularly on health and safety performance, feeding these lessons 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 inhouse 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
AHI	Asset health indices
ALARP	As low as reasonably practicable
AMDP	Asset management development plan
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
BAU	Business as usual
BCP	Business continuity plan
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
DGA	Dissolved gas analysis
DNO	Do not operate
DPP	Default price-quality path
DSM	Demand side management
DTM	Distribution Transformer Monitoring
EAMS	Enterprise asset management system
EDB	Electricity distribution business
ENA	Electricity Networks Association
ERT	Emergency response team
EV	Electric vehicle
FSA	Field service agreement

FTPP	Fast-tracked pole programme
GIS	Geospatial information system
GWh	Gigawatt hour
GXP	Grid exit point
HILP	High impact low probability (events)
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
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 back-up 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)
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
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
SWER	Single wire earth return
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

Schedule 11a: Report on forecast capital expenditure

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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
	11a(i): Expenditure on Assets Forecast	**$000 (in nominal dollars)**										
	Consumer connection	13,670	20,717	21,188	21,659	22,130	22,601	23,072	23,543	24,014	24,485	24,956
	System growth	22,040	11,087	19,726	27,049	33,090	28,401	18,694	26,382	26,567	24,774	28,694
	Asset replacement and renewal	53,286	58,107	42,926	49,249	56,365	59,285	63,139	59,226	56,710	51,960	52,168
	Asset relocations	4,484	2,218	2,269	2,319	2,370	2,420	2,470	2,521	2,571	2,622	2,672
	Reliability, safety and environment:											
	Quality of supply	1,682	542	645	2,198	3,468	4,904	6,049	5,581	5,090	4,575	4,663
	Legislative and regulatory											
	Other reliability, safety and environment											
	Total reliability, safety and environment	1,682	542	645	2,198	3,468	4,904	6,049	5,581	5,090	4,575	4,663
	Expenditure on network assets	95,161	92,673	86,755	102,475	117,424	117,611	113,425	117,253	114,952	108,415	113,153
	Expenditure on non-network assets	5,439	5,753	3,148	5,797	3,554	3,783	6,473	3,600	3,683	4,451	5,801
	Expenditure on assets	100,600	98,425	89,903	108,272	120,978	121,394	119,897	120,854	118,635	112,867	118,954
plus	Cost of financing	537	520	469	572	648	666	637	647	631	594	630
less	Value of capital contributions	12,532	13,040	13,336	13,632	13,929	14,225	14,522	14,818	15,114	15,411	15,707
plus	Value of vested assets											
	Capital expenditure forecast	88,605	85,906	77,036	95,212	107,697	107,834	106,013	106,682	104,152	98,050	103,876
	Assets commissioned	82,176	85,830	78,987	76,813	82,561	118,433	109,729	92,239	136,949	94,707	118,642

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		$000 (in constant prices)										
	Consumer connection	13,670	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911	19,911
	System growth	22,040	10,958	18,815	25,374	30,512	25,763	16,803	23,675	24,497	22,134	23,921
	Asset replacement and renewal	53,286	56,269	40,831	46,039	51,798	53,754	56,463	52,078	49,026	44,196	43,719
	Asset relocations	4,484	2,132	2,132	2,132	2,132	2,132	2,132	2,132	2,132	2,132	2,132
	Reliability, safety and environment:											
	Quality of supply	1,682	521	606	2,020	3,120	4,320	5,220	4,720	4,220	3,720	3,720
	Legislative and regulatory	-	-	-	-	-	-					
	Other reliability, safety and environment	-	-	-	-	-	-					
	Total reliability, safety and environment	1,682	521	606	2,020	3,120	4,320	5,220	4,720	4,220	3,720	3,720
	Expenditure on network assets	95,161	89,791	82,295	95,477	107,473	105,881	100,529	102,517	99,787	92,093	93,403
	Expenditure on non-network assets	5,439	5,529	2,958	5,329	3,198	3,333	5,586	3,045	3,054	3,620	4,628
	Expenditure on assets	100,600	95,320	85,254	100,806	110,671	109,213	106,115	105,562	102,841	95,713	98,031

Subcomponents of expenditure on assets (where known)
**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											
Cybersecurity (Commission only)											

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	-	806	1,277	1,748	2,219	2,690	3,161	3,632	4,103	4,574	5,045
System growth	-	129	911	1,675	2,579	2,638	1,891	2,706	2,070	2,640	4,774
Asset replacement and renewal	-	1,839	2,095	3,210	4,567	5,530	6,676	7,148	7,684	7,764	8,449
Asset relocations	-	86	137	187	238	288	338	389	439	490	540
Reliability, safety and environment:											
Quality of supply	-	21	39	177	348	584	829	861	870	855	943
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	21	39	177	348	584	829	861	870	855	943
Expenditure on network assets	-	2,882	4,459	6,998	9,951	11,730	12,895	14,736	15,165	16,322	19,750
Expenditure on non-network assets	-	224	190	468	356	450	887	555	629	832	1,173
Expenditure on assets	-	3,106	4,649	7,466	10,307	12,180	13,782	15,292	15,795	17,154	20,923

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** — $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Consumer Connection	13,670	19,911	19,911	19,911	19,911	19,911
**include additional rows if needed*						
Consumer connection expenditure	13,670	19,911	19,911	19,911	19,911	19,911
less Capital contributions funding consumer connection	8,497	10,464	10,413	11,061	11,947	11,947
Consumer connection less capital contributions	5,173	9,447	9,498	8,850	7,964	7,964

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	9,479	2,571	1,686	10,175	17,573	17,521
Zone substations	10,134	7,505	14,315	5,576	6,180	5,020
Distribution and LV lines	945	883	1,710	7,442	5,103	1,819
Distribution and LV cables	527	-	1,104	2,181	1,656	1,402
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	954	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	22,040	10,958	18,815	25,374	30,512	25,763
less Capital contributions funding system growth						
System growth less capital contributions	22,040	10,958	18,815	25,374	30,512	25,763

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	1,180	4,600	3,064	5,164	8,564	8,564
Zone substations	10,673	17,736	2,158	4,134	4,060	7,298
Distribution and LV lines	9,755	6,983	5,946	8,634	8,506	8,490
Distribution and LV cables	2,878	1,092	2,457	2,457	2,457	2,457
Distribution substations and transformers	702	1,677	1,667	1,107	1,424	1,780
Distribution switchgear	4,248	8,809	9,601	9,815	9,936	10,041
Other network assets	23,849	15,371	15,939	14,727	16,851	15,124
Asset replacement and renewal expenditure	53,286	56,269	40,831	46,039	51,798	53,754
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	53,286	56,269	40,831	46,039	51,798	53,754

11a(v): Asset Relocations

$000 (in constant prices)

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Asset Relocations	4,484	2,132	2,132	2,132	2,132	2,132
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	4,484	2,132	2,132	2,132	2,132	2,132
less Capital contributions funding asset relocations	4,035	1,077	1,077	1,077	1,077	1,077
Asset relocations less capital contributions	449	1,055	1,055	1,055	1,055	1,055

11a(vi): Quality of Supply

$000 (in constant prices)

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Future Networks	390	210	295	220	220	220
RSE	1,292	311	311	1,800	2,900	4,100
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	1,682	521	606	2,020	3,120	4,320
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,682	521	606	2,020	3,120	4,320

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Project or programme**	$000 (in constant prices)					
**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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Project or programme**	$000 (in constant prices)					
**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	5,439	5,529	2,958	5,329	3,198	3,333
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	5,439	5,529	2,958	5,329	3,198	3,333
Atypical expenditure						
*Project or programme**						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	5,439	5,529	2,958	5,329	3,198	3,333

Schedule 11b: Report on forecast operational expenditure

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this 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
Operational Expenditure Forecast	**$000 (in nominal dollars)**										
Service interruptions and emergencies	3,447	3,738	3,792	3,884	3,975	4,067	4,201	4,338	4,476	4,618	4,762
Vegetation management	3,927	4,023	4,132	4,173	4,304	4,414	4,452	4,586	4,697	4,731	4,867
Routine and corrective maintenance and inspection	13,387	13,824	14,283	18,740	19,119	18,716	17,178	16,696	16,611	17,750	17,643
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	20,761	21,585	22,207	26,798	27,399	27,198	25,832	25,620	25,784	27,099	27,272
System operations and network support	16,399	19,226	18,398	18,123	18,523	18,860	19,555	19,450	19,679	20,140	20,543
Business support	15,350	15,908	14,931	14,885	15,241	15,524	16,074	16,358	16,621	17,017	17,388
Non-network opex	31,749	35,134	33,328	33,009	33,764	34,384	35,629	35,809	36,299	37,157	37,931
Operational expenditure	52,510	56,719	55,535	59,806	61,163	61,581	61,461	61,428	62,083	64,256	65,202

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	$000 (in constant prices)										
Service interruptions and emergencies	3,447	3,613	3,582	3,587	3,591	3,596	3,637	3,678	3,719	3,762	3,804
Vegetation management	3,927	3,888	3,902	3,854	3,888	3,902	3,854	3,888	3,902	3,854	3,888
Routine and corrective maintenance and inspection	13,387	13,384	13,503	17,309	17,261	16,526	14,841	14,121	13,759	14,406	14,035
Asset replacement and renewal											
Network Opex	20,761	20,885	20,987	24,750	24,741	24,025	22,332	21,687	21,381	22,021	21,727
System operations and network support	16,399	18,524	17,348	16,733	16,753	16,716	16,992	16,576	16,454	16,528	16,551
Business support	15,350	15,374	14,103	13,747	13,769	13,725	13,915	13,871	13,811	13,863	13,893
Non-network opex	31,749	33,898	31,451	30,480	30,521	30,441	30,907	30,447	30,265	30,390	30,444
Operational expenditure	52,510	54,784	52,438	55,230	55,262	54,466	53,239	52,134	51,646	52,411	52,171

Subcomponents of operational expenditure (where known)

'EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Energy efficiency and demand side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance											
Cybersecurity (Commission only)											

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and real forecasts	**$000**										
Service interruptions and emergencies	-	125	210	297	384	471	565	660	757	856	958
Vegetation management	-	134	229	319	416	512	598	697	794	877	979
Routine and corrective maintenance and inspection	0	440	780	1,432	1,858	2,190	2,337	2,575	2,852	3,344	3,608
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Network Opex	0	699	1,220	2,048	2,658	3,173	3,499	3,932	4,403	5,078	5,545
System operations and network support	-	702	1,049	1,390	1,770	2,144	2,563	2,874	3,225	3,612	3,991
Business support	-	534	828	1,139	1,473	1,799	2,160	2,487	2,810	3,154	3,495
Non-network opex	-	1,236	1,877	2,529	3,243	3,943	4,722	5,362	6,034	6,767	7,487
Operational expenditure	0	1,935	3,097	4,577	5,900	7,116	8,222	9,294	10,437	11,845	13,031

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 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	**1 April 2024 – 31 March 2034**

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												
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.	0.12%	1.13%	0.32%	75.60%	22.83%	-	3	2.65%
11	All	Overhead Line	Wood poles	No.	3.67%	3.47%	22.68%	53.44%	16.73%	-	3	15.36%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	16.50%	3.62%	0.07%	10.28%	69.52%	-	2	6.71%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0.05%	-	-	3.00%	96.95%	-	2	0.05%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	33.00%	-	67.00%	-	2	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	48.47%	-	-	51.53%	-	2	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	31.49%	-	-	54.41%	14.10%	-	2	5.99%
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.	34.38%	6.25%	9.38%	18.75%	31.25%	-	2	6.25%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	14.29%	11.90%	28.57%	45.24%	-	2	23.81%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	5.36%	10.71%	16.07%	21.43%	46.43%	-	2	30.36%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	37.01%	3.25%	0.65%	8.44%	50.65%	-	2	13.64%
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.	-	-	-	-	100.00%	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	24.48%	-	14.03%	8.96%	52.54%	-	3	13.73%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	52.00%	16.00%	32.00%	-	2	48.00%
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37	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
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.08%	9.23%	23.08%	26.15%	38.46%	-	3	13.85%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.97%	2.53%	5.66%	15.28%	73.55%	-	2	5.43%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	12.75%	-	-	5.39%	81.86%	-	2	31.82%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.04%	0.49%	0.20%	0.22%	99.05%		2	0.73%
44	HV	Distribution Cable	Distribution UG PILC	km	0.00%	-	0.04%	7.92%	92.04%		2	0.17%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100.00%		2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	5.08%	6.78%	88.14%	-	2	6.78%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	66.67%	-	33.33%	-	-	-	2	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	10.70%	3.12%	5.18%	11.17%	69.84%	-	2	8.55%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	11.67%	12.58%	67.58%	0.76%	7.42%	-	2	43.33%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.21%	9.30%	42.74%	-	47.75%	-	3	14.42%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	4.32%	3.91%	8.28%	16.33%	67.16%	-	3	3.52%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.18%	1.19%	2.17%	7.02%	89.45%	-	3	1.22%
53	HV	Distribution Transformer	Voltage regulators	No.	9.38%	-	-	15.63%	75.00%	-	3	9.38%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	12.35%	1.53%	7.47%	15.54%	63.10%	-	2	8.66%
56	LV	LV Cable	LV UG Cable	km	0.83%	0.81%	0.81%	5.10%	92.46%		2	0.20%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	4.25%	1.87%	8.53%	24.91%	60.44%	-	1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	-	N/A	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	51.57%	7.04%	12.96%	28.43%	-	-	3	35.85%
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%	-	2	-
62	All	Load Control	Centralised plant	Lot	-	-	-	66.67%	33.33%	-	2	-
63	All	Load Control	Relays	No.	6.98%	1.61%	5.41%	15.45%	70.55%	-	2	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Schedule 12b: Report on forecast capacity

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Alexandra	11	15	N-1 switched	4	74%	15	85%	No constraint within +5 years	
10	Clyde/Earnscleugh	4	-	N	4	-			No constraint within +5 years	Due to aging assets, Clyde/Earnscleugh (CE) substation will be replaced by the new Dunstan substation (aimed to be completed by RY26). We will transfer the load of CE to the new Dunstan substation by RY27 and decommisison CE by RY28. We have reinforced the CE distribution network to provide better back-up supply from Alexandra substation.
11	Earnscleugh	-	-	-	-	-			No constraint within +5 years	Earnscleugh provides short term partial back up to Clyde/Earnscleugh. We plan to decomission Earnscleugh when the distribution feeders of Clyde/Earnscleugh substation have been transferred to the new Dunstan substation by RY28. We have reinforced the Clyde/Earnscleugh network to provide back-up supply from Alexandra.
12	Dunstan	-	-	N		-			No constraint within +5 years	The new Dunstan substation is expected to be completed by RY26 and Clyde/Earnscleugh load will be transferred in RY27.
13	Ettrick	2	-	N	1	-			No constraint within +5 years	The substation is scheduled to be renewed in RY33. This provides an oppurtunity to install standard transformer size and 11kV switchgear to reconfigure the distribution network to uplift the reliability.
14	Lauder Flat	1	-	N	0	-			Subtransmission circuit	The Lauder Flat transformer is planned to be replaced by RY31. The capacity of Alexandra-Omakau 33kV subtransmission (N-security) that supplies Omakau and Lauder Flat substations is limited by voltage because of the squirrel and ferret conductors in the circuit. We plan to increase capacity and security at Omakau substation by installing a second transformer to compensate for the growth and voltage, this also provides an oppurtunity to supply Lauder Flat (LF) with two feeders and decommission the LF substation instead of replacing the transformer. Further, we plan to develop in stages a second Alexandra-Omakau subtransmission line and rebuild the existing 33kV subtransmission circuit in the later part of the 10-year period.
15	Omakau	3	-	N	0	-			Subtransmission circuit	We are rebuilding Omakau zone substation in a new location along SH85 which is planned to be completed by RY24. Omakau demand is forecast to grow within the ten year horizon. However, the capacity of Alexandra-Omakau 33kV subtransmission (N-security) that supplies Omakau and Lauder Flat substations is limited by voltage because of the squirrel and ferret conductors in the circuit. To increase capacity and security at Omakau substation; (1) we plan to install a second transformer to compensate for the growth and voltage, this also provides an oppurtunity to supply Lauder Flat (LF) with two feeders and decommission the LF substation and (2) develop in stages a second Alexandra-Omakau subtransmission line and rebuild the existing 33kV subtransmission circuit in the later part of the 10-year period.
16	Roxburgh	2	-	N	1	-			No constraint within +5 years	

17		Camp Hill	6	-	N	1	-			Transformer	There is strong growth in the Camp Hill (CH) area and the demand is forecast to reach the capacity by 2029. We plan to install transformer fans to increase capacity from 7.5 to 10MVA. We plan to develop a substation in the Luggate area by 2031, transfer load from CH, Queensberry, some of Riverbank and rationalise the distribution network to improve reliability by 2033.
18		Cardrona	24	-	N	0	-			No constraint within +5 years	We have recently completed the replacement of the 5MVA transformer with 24MVA transformer thereby increasing the capacity of the substation.
19		Cromwell	14	24	N-1	0	58%	24	83%	No constraint within +5 years	
20		Lindis Crossing	9	-	N	1	-			Transformer	We have increased capacity by adding fans to cater for load transfer from Queensberry. The forecast indicates that the demand will be above the new capacity by 2030. We plan to increase capacity and security in two stages in the 10-year horizon. Stage 1 is to install 24MVA transformer by RY27 and a second 24MVA transfoprmer by RY33. This plan would also move load from Queensberry to Lindis Crossing.
21		Queensberry	3	-	N	1	-			Transformer	We plan to transfer load of Queensberry to the proposed new substation in the vicinity of the Luggate and Lindis Crossing.
22		Wanaka	26	24	N-1	3	106%	24	90%	Transformer	We are installing a new 24 MVA transformer at Riverbank switching station in RY24/25 and transfer load from Wanaka substation in RY24/25. Operationally, we have the capability to move >1MVA load to Camp Hill substation.
23		Riverbank	-	-	N		-			No constraint within +5 years	We are installing a new 24 MVA transformer at Riverbank switching station in RY24/25 and transfer load from Wanaka substation in RY24/25. We have alloted an express feeder between Wanaka and Riverbank to accommodate for a contingent event at Riverbank.
24		New substation (Luggate surrounds)					-				We plan to be develop a new substation and the distribution feeders in RY33 to cater for load growth in Luggate and its surrounds. The proposed new substation will take the load of Queensberry substation in the area, some load of Camp Hill substation, some of Riverbank and rationalise the distribution network to improve reliability.
25		Arrowtown	10	10	N-1 switched	1	96%	10	99%	Transformer	The substation is planned to be renewed and rebuilt in a new location at the later part of the ten year plan. In the medium term, we plan to transfer some load of Arrowtown to a new zone substation in the Whakatipu area.
26		New zone substation (rebuild of Arrowtown)					-				This new substation will replace the existing Arrowtown substation at a new location in the later part of the ten year plan. The plan includes to rationalise the distribution network to improve reliability and strengthen the interconnection with adjacent substations' feeders.
27		Commonage	12	17	N-1 switched	6	69%	17	74%	No constraint within +5 years	
		Coronet Peak	5	-	N-1	1	-		-	No constraint within +5 years	A new zone substation will be built in the Whakatipu basin to take over the load from this zone substation site.
		Dalefield	2	-	N	1	-		-	Transformer	There is strong growth at Dalefield and Arthurs point. The demand is forecast to be above the capacity by RY27. Further, the substation is scheduled to be renewed by RY30. We plan to rebuild the substation at a new location with a security level of N-1.
		New zone substation (rebuild of Dalefield)					-				We plan to renew and rebuild the Dalefield substation at a new location at the Whakatipu basin with a security level of N-1 in RY26. The new substation will take over the load of Dalefield substation, Coronet Peak substation, parts of Frankton distribution network at Dalefield area and parts of Arrowtown distribution network at Speargrass area.
		Fernhill	7	10	N-1 switched	1	65%	10	88%	No constraint within +5 years	The forecast shows that the demand will be nearing the substation capacity by RY34. We will be monitoring the demand and plan accordingly.
		Frankton	18	15	N-1	1	121%	24	96%	Transformer	We are replacing the smaller size transformer with a 24 MVA transformer to increase capacity and security by RY25. There area is experiencing demand growth. We will be monitoring the load growth in the area to assist in what options to progress.
		Queenstown	13	20	N-1 switched	2	64%	20	78%	No constraint within +5 years	
		Remarkables	2	-	N	0	-		-	No constraint within +5 years	

	Berwick	2	-	N	0	-		-	No constraint within +5 years	
	East Taieri	19	24	N-1 switched	2	78%	24	84%	No constraint within +5 years	
	Green Island	14	18	N-1	3	78%	18	86%	No constraint within +5 years	
	Halfway Bush	14	18	N-1	2	77%	18	80%	No constraint within +5 years	
	Kaikorai Valley	11	23	N-1	7	46%	23	49%	No constraint within +5 years	
	Mosgiel	7	12	N-1 switched	1	61%	12	99%	No constraint within +5 years	The substation's transformers and 33kV outdoor bus is planned to be renewed by RY32. The forecast indicates that the demand will be above the substation's capacity in RY31. We plan to replace the transformers with 24MVA size and have a 33kV indoor switchgear by RY31 to cater for the forecast load.
	North East Valley	11	18	N-1	5	60%	18	63%	No constraint within +5 years	
	Outram	3	-	N	1	-		-	No constraint within +5 years	
	Port Chalmers	8	10	N-1	1	77%	10	93%	No constraint within +5 years	The transformers is planned to be replaced with larger size transformers by RY27.
	Smith Street	13	18	N-1	10	70%	18	89%	No constraint within +5 years	The transformers is planned to be replaced with larger size transformers by RY25.
	Ward Street	10	23	N-1	5	41%	23	55%	No constraint within +5 years	Includes the New Dunedin Hospital (NDH) - Inpatient building load. Ward substation will provide back-up supply to NDH - Outpatient building.
	Willowbank	13	18	N-1	3	72%	18	73%	No constraint within +5 years	
	Andersons Bay	15	24	N-1	0	63%	24	68%	No constraint within +5 years	
	Carisbrook	11	18	N-1	4		18	67%	No constraint within +5 years	
	Corstorphine	13	23	N-1	5		23	60%	No constraint within +5 years	
	North City	16	28	N-1	6	58%	28	63%	No constraint within +5 years	Includes the New Dunedin Hospital (NDH) - Outpatient building load. North City substation will provide back-up supply to NDH - Inpatient building. The cost to relocate North City zone substation (if required by the MoH) has not been included in our financial forecasts.
	South City	16	18	N-1	8		18	88%	No constraint within +5 years	
28	St Kilda	15	23	N-1	6	67%	23	79%	No constraint within +5 years	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c: Report on forecast network demand

	Company Name	**Aurora Energy Limited**
	AMP Planning Period	**1 April 2024 – 31 March 2034**

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*
10							
11	*Consumer types defined by EDB**						
12	Residential	892	1,134	1,150	1,166	1,182	1,199
13	Load Group 0	1	4	5	6	6	6
14	Load Group 0A	(75)	-	8	12	14	15
15	Load Group 1A	18	17	17	17	17	17
	Load Group 1	40	67	80	87	90	92
	Load Group 2	141	135	132	131	130	130
	Load Group 3	4	4	4	4	4	4
	Load Group 3A	11	7	5	4	4	4
	Load Group 4	2	3	3	3	3	3
	Load Group 5	-	-	-	-	-	-
16	Street Lighting & DUML	-	-	-	-	-	-
17	**Connections total**	1,034	1,371	1,404	1,430	1,450	1,470
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	657	669	681	681	681	681
24	Capacity of distributed generation installed in year (MVA)	6	3	3	3	3	3
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	267	275	290	302	310	320
29	*plus* Distributed generation output at HV and above	57	57	57	58	58	59
30	**Maximum coincident system demand**	325	332	347	360	368	379
31	*less* Net transfers to (from) other EDBs at HV and above	1	1	1	1	1	1
32	**Demand on system for supply to consumers' connection points**	324	331	347	359	368	379
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	1,182	1,188	1,197	1,208	1,221	1,236
35	*less* Electricity exports to GXPs	41	41	41	41	41	41
36	*plus* Electricity supplied from distributed generation	349	397	446	494	542	591
37	*less* Net electricity supplied to (from) other EDBs	2	2	2	2	2	2
38	**Electricity entering system for supply to ICPs**	1,487	1,542	1,599	1,658	1,719	1,783
39	*less* Total energy delivered to ICPs	1,405	1,457	1,511	1,567	1,625	1,685
40	**Losses**	82	85	88	91	94	98
41							
42	**Load factor**	52%	53%	53%	53%	53%	54%
43	**Loss ratio**	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%

Schedule 12d: Report on forecast interruptions and duration

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
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)	177.3	142.3	143.7	135.4	153.9	138.2
12	Class C (unplanned interruptions on the network)	153.9	143.7	143.7	141.2	138.9	136.7
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.62	0.62	0.63	0.60	0.67	0.61
15	Class C (unplanned interruptions on the network)	2.07	1.96	1.96	1.95	1.94	1.91

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Dunedin sub-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)	127.0	80.0	96.8	98.2	89.7	79.6
12	Class C (unplanned interruptions on the network)	71.5	72.8	72.8	71.6	70.4	69.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.48	0.38	0.45	0.45	0.41	0.37
15	Class C (unplanned interruptions on the network)	0.98	0.99	0.99	0.99	0.98	0.97

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Central Otago and Wanaka sub-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)	282.6	282.2	212.7	198.3	289.5	264.7
12	Class C (unplanned interruptions on the network)	281.7	278.4	278.4	273.5	269.2	264.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.94	1.15	0.93	0.86	1.25	1.13
15	Class C (unplanned interruptions on the network)	4.31	3.80	3.80	3.77	3.75	3.70

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Queenstown sub-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)	206.8	178.9	178.9	188.7	216.6	183.2
12	Class C (unplanned interruptions on the network)	270.6	205.2	205.2	201.6	198.4	195.2
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.66	0.76	0.88	0.74	0.74	0.68
15	Class C (unplanned interruptions on the network)	2.74	2.80	2.80	2.78	2.76	2.73

Schedule 13: Report on asset management maturity

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

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 Asst Management Policy is authorised by Chair and CEO and published within our Controlled Document System. Our Asset Management Policy was reviewed in late 2022 with Board approval in 2023. It has an active role in informing the development of our SAMP and lower level asset management strategies		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		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).

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

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.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

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 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		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.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

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.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

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 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. Further improvement requires a proactive 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 alignement with ISO 55000. There are regular team briefings and newsletters from top management to all 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.

Company Name	Aurora Energy Limited
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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 engagement 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 considerable number of AMS documents in place and the main processes and the interactions between them have been documented in Promapp. Further work is required to complete the document set and keep them up to date as the business evolves.		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	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 by field and internal staff and that the GIS is aligned with Grid Plans, and that the ADMS and 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 uses Comply Watch to monitor the regulatory environment. The Comply With system is used for internal compliance identification purposes.		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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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 made some progress, reviewing current Pole inspection programme and extending it to capture OH assets, including Conductors, we have written a set of guidance docs and provided training to end users. We have a lot of work to do in this space. Fleet Strategies 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.

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2024 – 31 March 2034
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Aurora Energy Limited**
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Asset Management Standard Applied	**ISO 55001**

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 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	We are documenting change, and opportunities for improvements at a fleet level, in our Fleet Strategy documents. We have a commenced a Cost Estimation/Scoping Improvement project for Major Projects. We are become more focused on continuous improvement in our day to day management of assets.		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?	2	We engage with industry/other EDBs re NEMA and introduction of new tech, we attend EEA facilitated roadshows, we work with suppliers and labs re RCA . We capture learnings and our response to those learnings in our Fleet Strategy Documents, We are working to create an opportunity to engage more with our field crews re learnings. We are associated with Professional Organisations such as IAM, ENZ, EEA		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.

Company Name	Aurora Energy Limited
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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 2024 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 towards key business areas, including our asset management practices, data systems, and approaches to cost estimation. In these areas, we believe that 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. In order to ensure that 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 that failure. Our key initiatives include further development of our modelling for understanding asset health and criticality. Refined health modelling will help us to better identify the likelihood of asset failure and to implement appropriate preventive measures.

Criticality helps us to understand the potential consequences of asset failure so that we might introduce appropriate controls. In 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 where we prioritised replacements in areas of high traffic or public density such as main roads, schools and tertiary institutions.

[10] See Electricity Distribution Information Disclosure (Aurora Energy Limited) Amendment Determination 2021 available here

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, 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 to 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 the capture of as-built costs. Also, we will put in place an annual unit rate review process to ensure that 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 that 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 that 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 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: 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	(System Average Interruption Duration Index) SAIDI represents the average number of minutes of power outages that an average consumer has experienced over a year
SAIFI	(System Average Interruption Frequency Index) SAIFI 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	(Major Event Day) Events that have a significant impact on the network within a short timeframe. These events are typically driven by uncontrollable factors such as extreme weather, and so the SAIDI/SAIFI impact is assessed at a lower value
Assessed SAIDI/SAIFI	Annual SAIDI/SAIFI minus any discounted values
Regulatory Limit	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	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 given 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.[11] 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

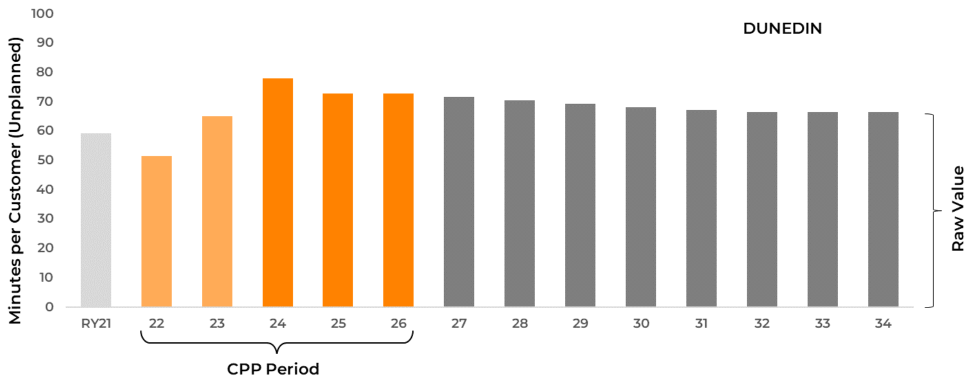
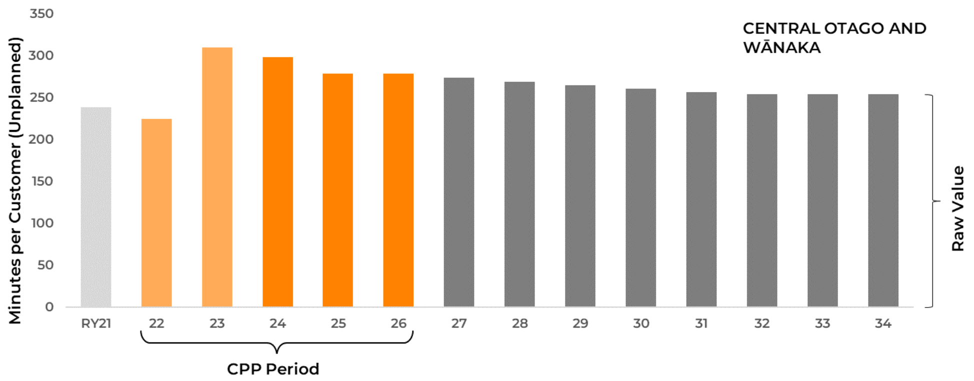
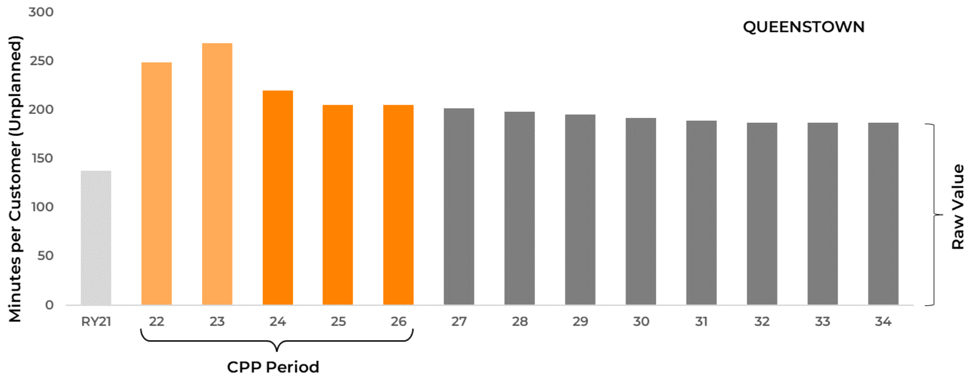


Figure 17-2: Unplanned SAIDI - Central Otago & Wānaka



[11] Regulatory targets are yet to be set for the period beyond the current CPP.

Figure 17-3: Unplanned SAIDI - Queenstown

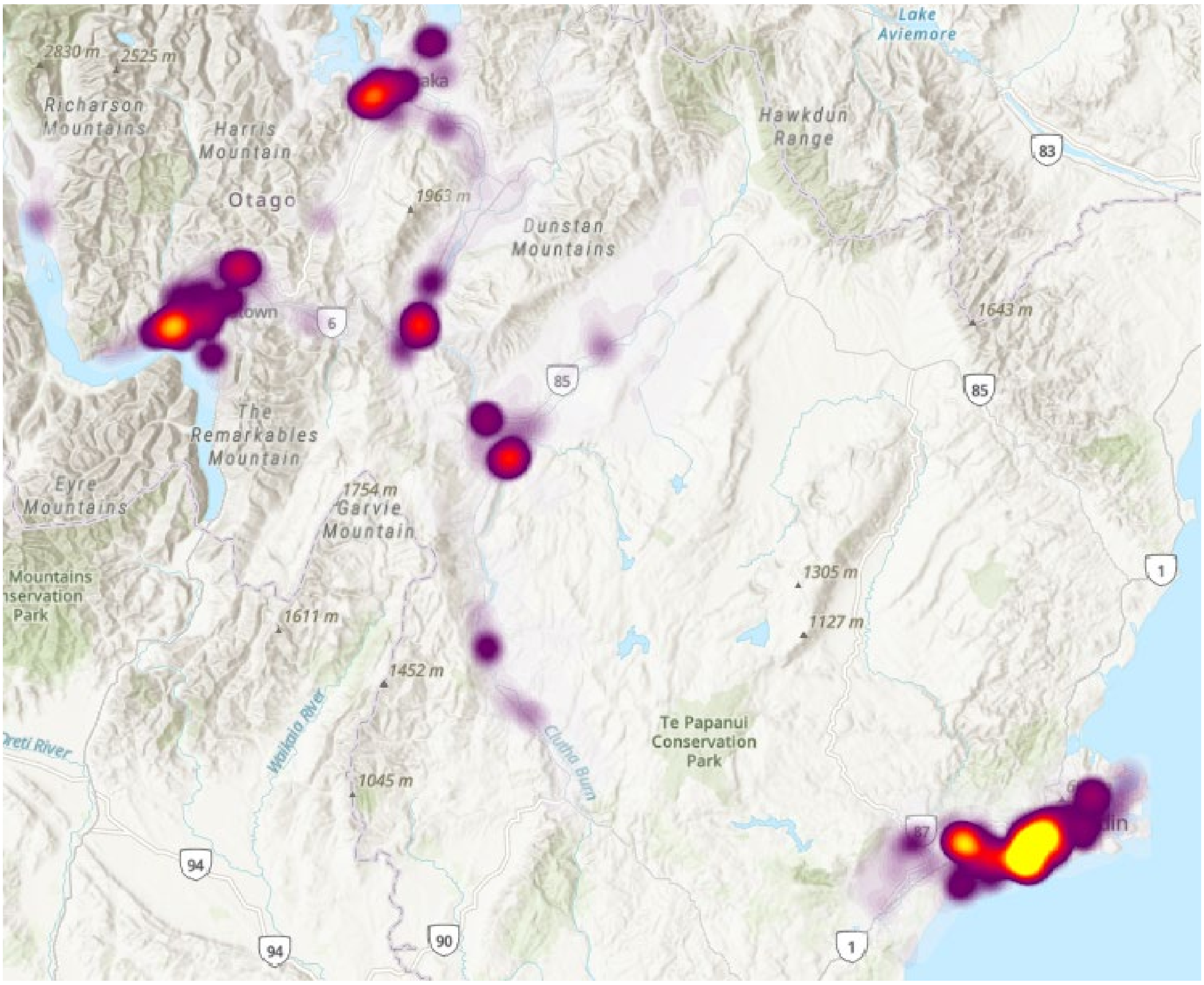


Overall, the Dunedin sub-network performs at a high level of reliability, with the average consumer experiencing only a single unplanned outage on an annual basis. Consumers in our other sub-networks tend to experience a greater number of outages overall, particularly in recent years – our forecast indicates 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, and so it is not feasible for all consumers to expect the same level of performance. The key regional differences are summarised in Table 17-6 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 100s per network kilometre In contrast, rural areas have as few as 1–5 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, and so we generally 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, and 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 the 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 that 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. 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 then communicated with affected customers to acknowledge the poor performance in their area, and to outline our upcoming planned expenditure.

We will continue to monitor the performance of our known reliability hotspots, and we will expand the initiative to include other areas that are experiencing a deteriorating trend in reliability.

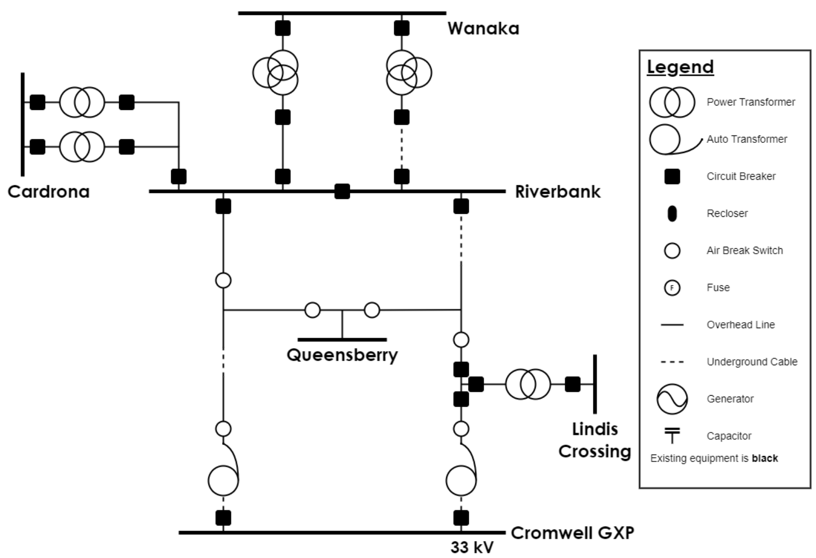
APPENDIX E: Growth Project Details

The following tables set out our main planned major network development projects for the AMP planning period.

Table 17-4: Upper Clutha Voltage Support

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Upper Clutha Voltage Support	During peak load, the voltage drops below 66 kV particularly when one of the two circuits is out of service	• Do Nothing • Install 10 MVAr of voltage support at Riverbank substation • Install a total of 10 MVAr of voltage support on the 11 kV bus of Wanaka, Cardrona and Lindis Crossing substation	**Install a total of 10 MVAr of voltage support on the 11 kV bus of Wanaka, Cardrona and Lindis Crossing zone substations** This solution provides the following benefits: • Significantly improves the network voltages on the Upper Clutha 66 kV network • Reduces network losses • Removes the risk to shed consumer load in the event of the loss of one of the Cromwell–Riverbank circuits	2021–24	6

Existing



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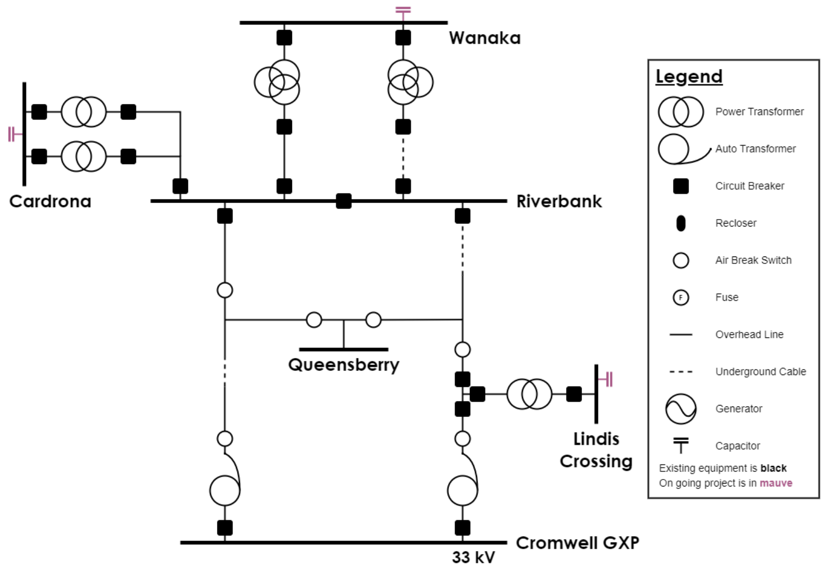
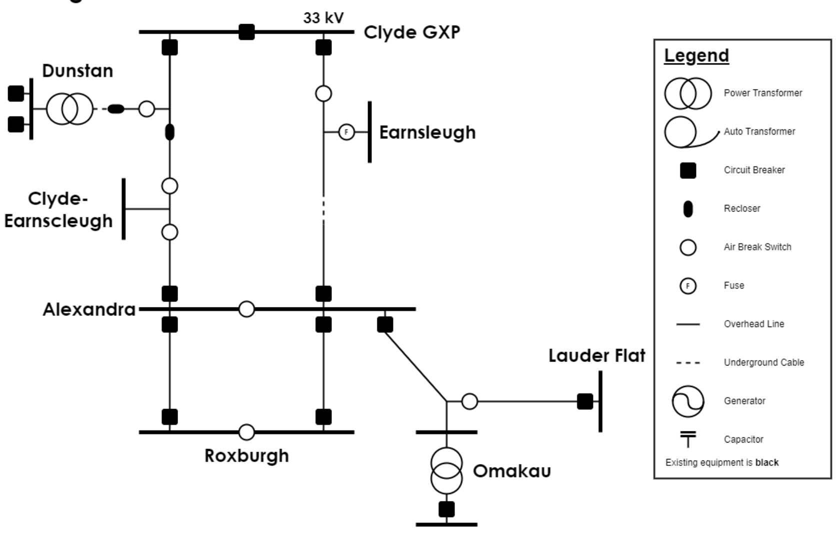


Table 17-5: Omakau New Zone Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Omakau New Zone Substation	The load of the single power transformer has reached its capacity The substation has limited backfeed from adjacent substations and does not have a mobile parking area 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 parking 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 parking 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 • Fits in with our long-term strategy to have the Omakau and Lauder Flat provide backup to one another	2021–24	3.1

Existing



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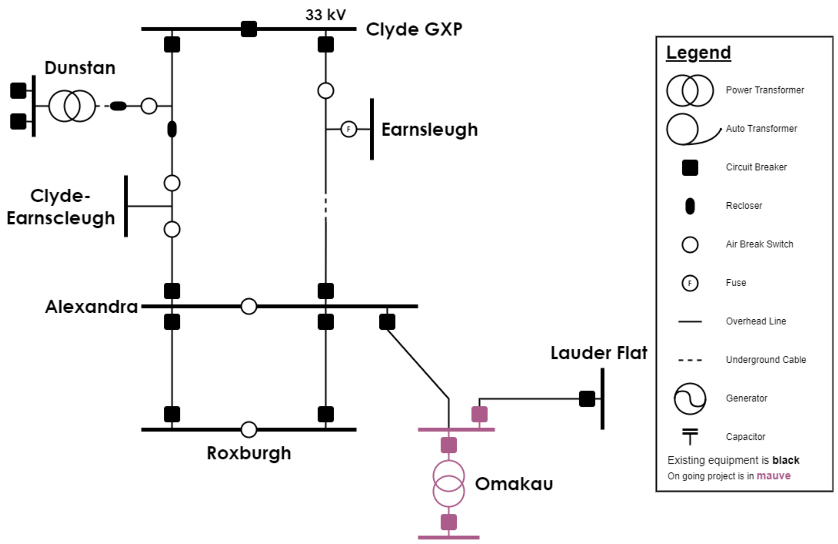
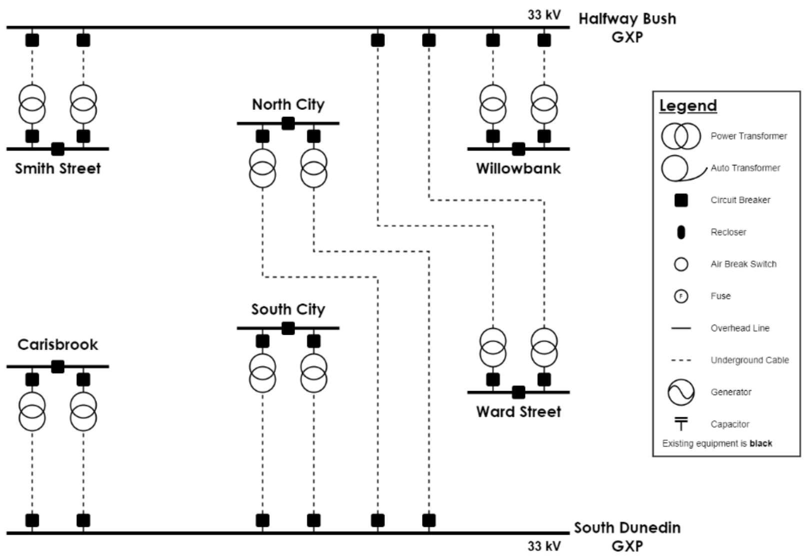


Table 17-6: Dunedin Subtransmission Ring Configuration

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	2031–32	3.5
			South City to Ward Street	2031–33	2.8
			South City to Carisbrook	2032–34	6.2
			North City to Ward Street	2033–35	3.5

Existing



Future

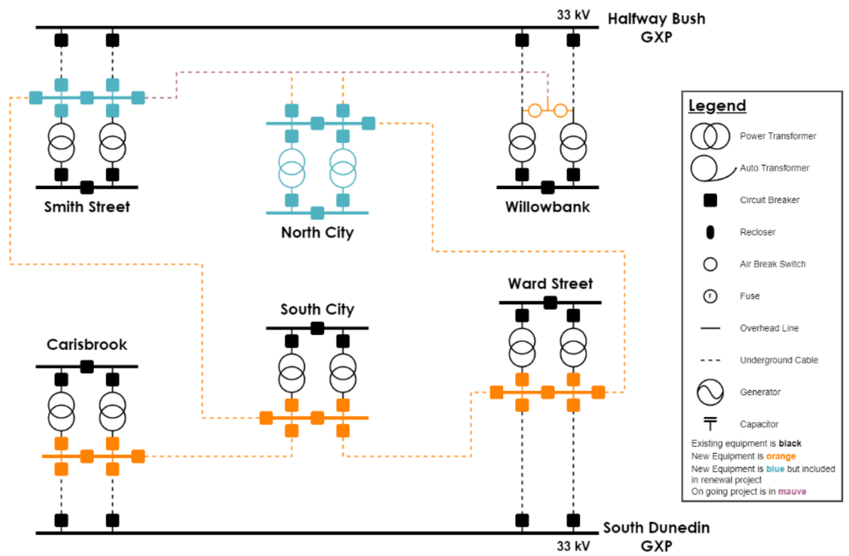


Table 17-7: Malaghans Substation (New Dalefield)

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 some Arrowtown load	**New zone substation to replace Dalefield and Coronet Peak and some Arrowtown load** This solution provides the following benefits: • Provides increased capacity • Removes two small "N" substations that were difficult to provide backup for • 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	2025–26	10.9

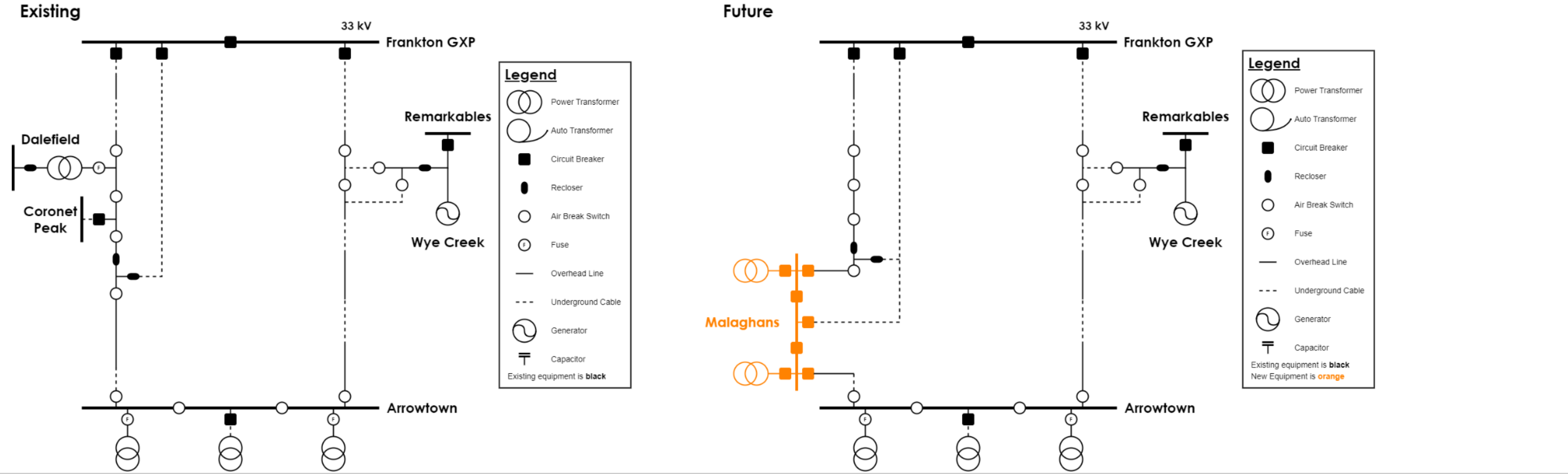
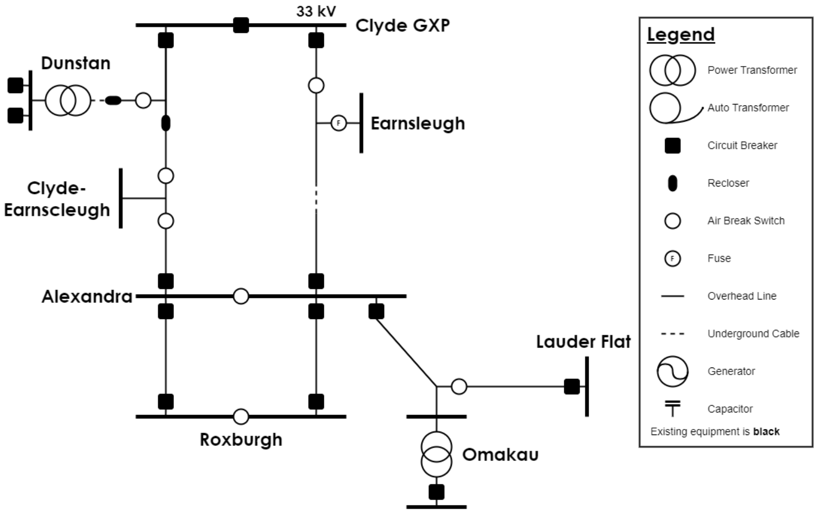


Table 17-8: Dunstan Stage 2

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Dunstan Stage 2	Growing irrigation load on the Clyde/Earnscleugh substation is beginning to 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	1.8

Existing



Future

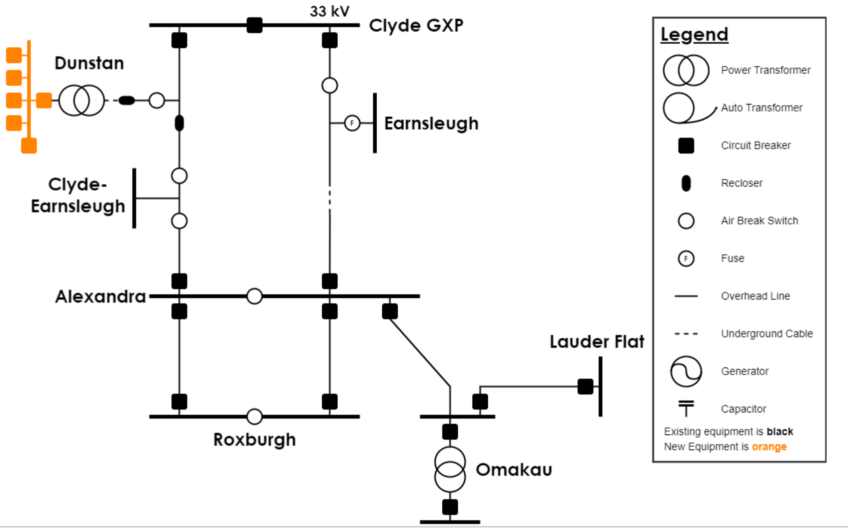


Table 17-9: Lindis Crossing Capacity Upgrade Stage 1

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Lindis Crossing Capacity Upgrade Stage 1	The firm capacity is forecast to be exceeded during RY24.	• Do Nothing • Install a new 24MVA transformer and extend 11 kV switchgear at Lindis Crossing zone substation • As above, with 6MVA transformer (ex-Cardrona) • Rebuild Queensberry zone substation with a new 7.5 MVA transformer at a new site	**Install new 24MVA 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	2026–27	3.9

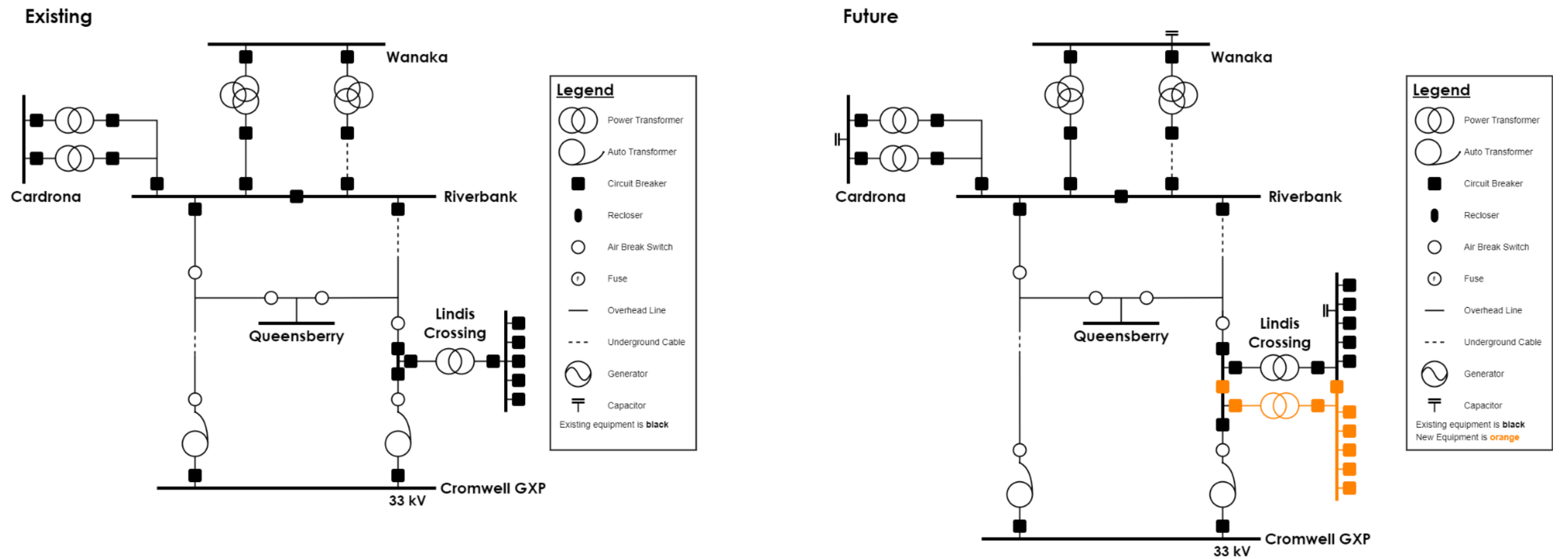
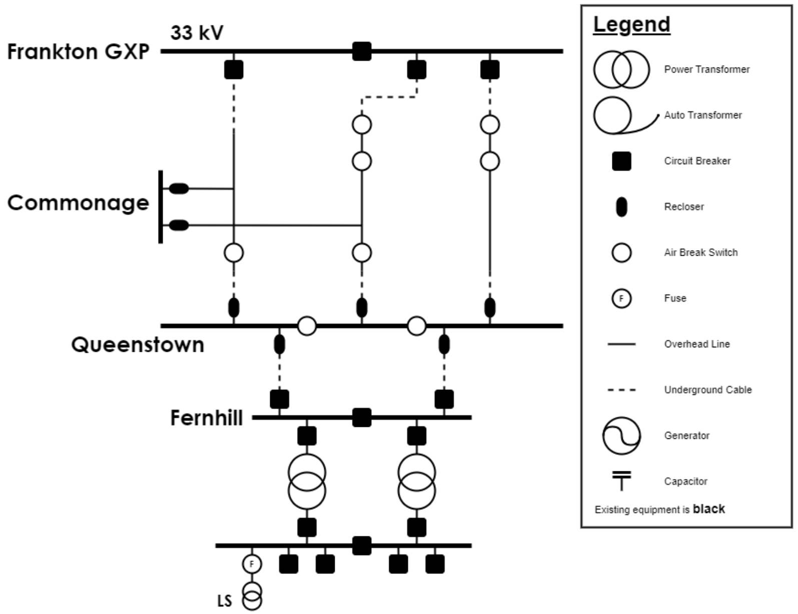


Table 17-10: Fernhill Additional Circuit breakers

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Fernhill Additional Circuit breakers	Fernhill substation has insufficient feeders to meet growing needs Queenstown load growth is expected to cause Queenstown substation N-1 capacity to be exceeded in 2028	• Add new half bus and two new feeders to Fernhill • Replace entire Fernhill 11kV bus with new larger bus with additional feeders	**Add new half bus and two new feeders to Fernhill** This solution provides the following benefits: • Allows load to be transferred from Queenstown to Fernhill and growing load to be fed by Fernhill • Simplifies off-loading of Fernhill feeders when outages are required • Provides a path for future upgrading of Fernhill by eventual replacement of entire bus followed by Transformer replacement	2026–27	1.0

Existing



Future

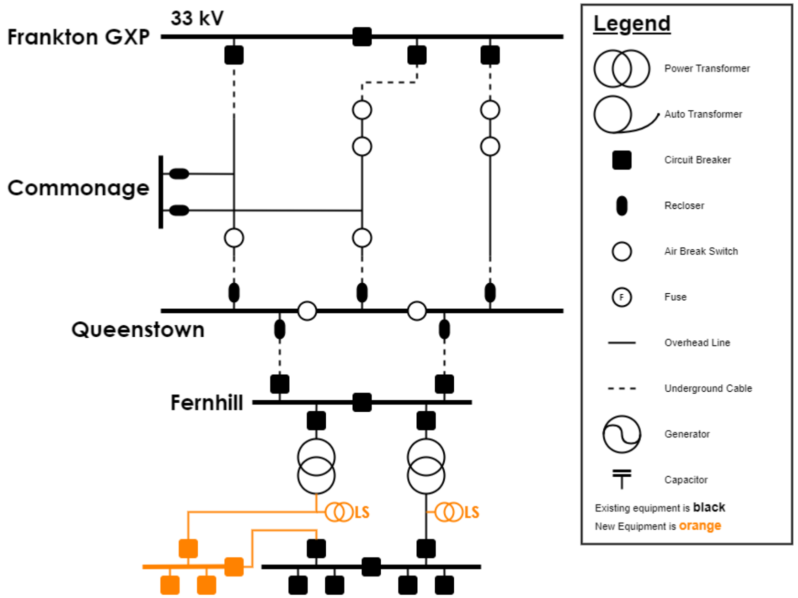


Table 17-11: Queensberry New 66 kV Bus

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Queensberry New 66 kV Bus	Growing Load in the Upper Clutha area is becoming Increasingly difficult to supply for a 66 kV line outage Queensberry growing load is exceeding capacity of existing transformer	• Install simplified 66 kV bus at Queensberry and upgrade Queensberry Transformer • Rebuild Queensberry on new site with 66 kV bus and larger transformer	**Install simplified 66 kV bus at Queensberry** This solution provides the following benefits: • 66 kV line outage causes much less voltage issues (particularly at LC for CML-LC outage) • Permanent tie at Queensberry reduces protection problems with existing need for temporary ties without CBs • Feeds growing load at QB and QB load no longer lost for single 66 kV line fault	2027–28	4.1

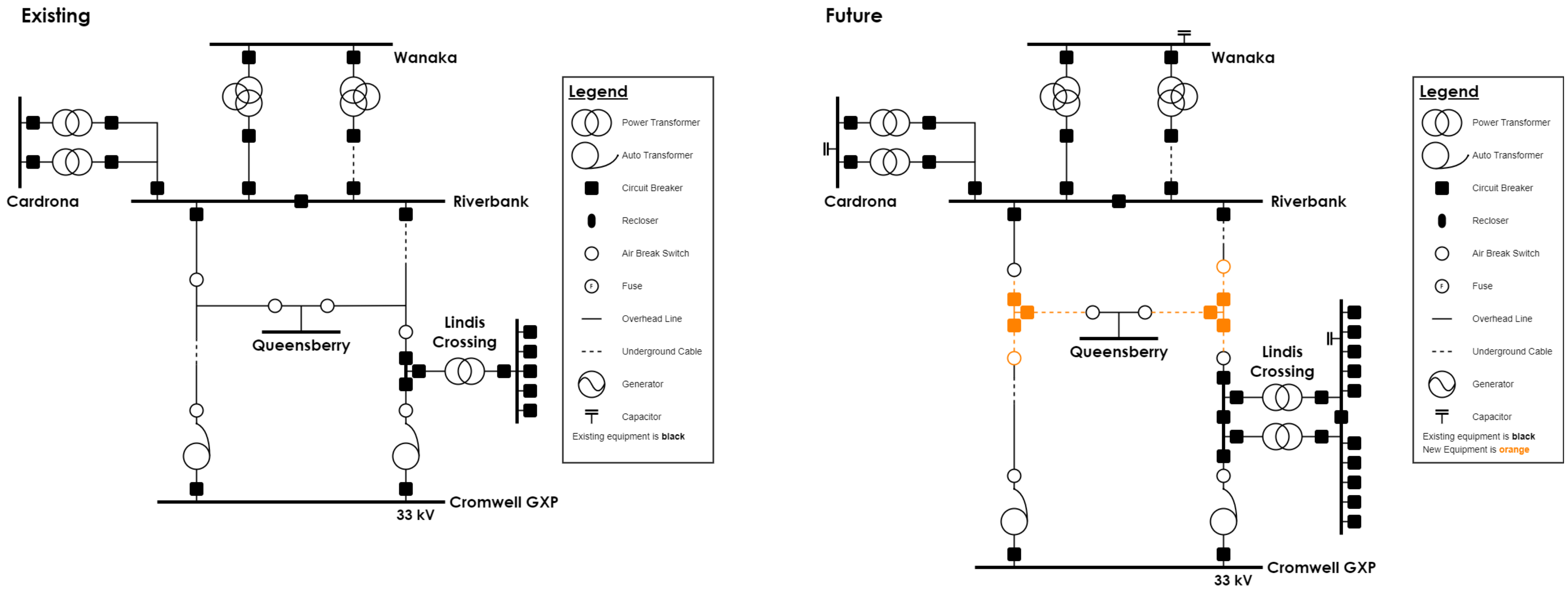
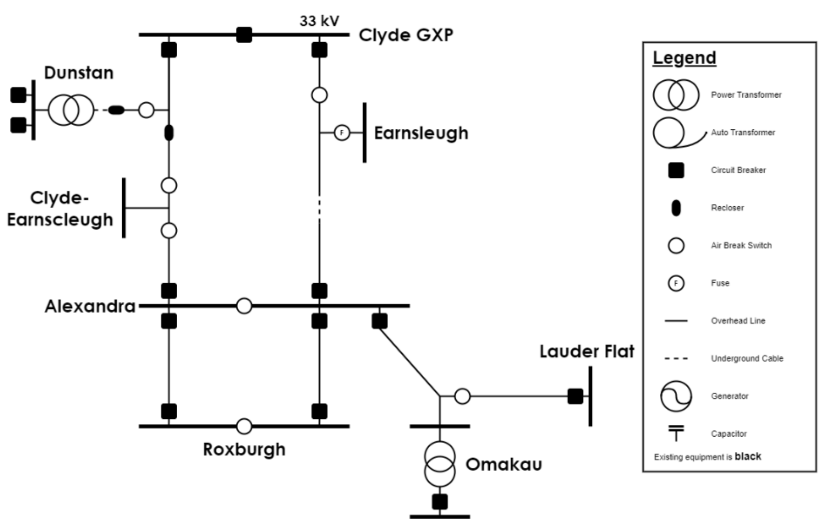


Table 17-12: Omakau Second Transformer

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Omakau Second Transformer	Growing Irrigation load in the Omakau - Lauder Flat area		**Install a second transformer at the Omakau substation** This solution provides the following benefits: • Provides backup to the existing transformer • Reduces voltage drop issues • Enables future decommissioning of Lauder Flat zone substation with conversion of 33 kV line from Omakau to Lauder Flat to 11 kV	2027–28	2.9

Existing



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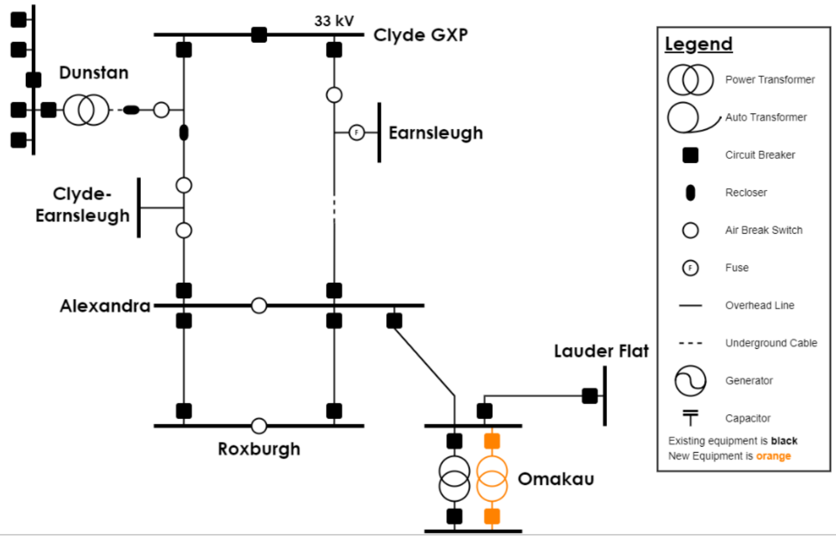
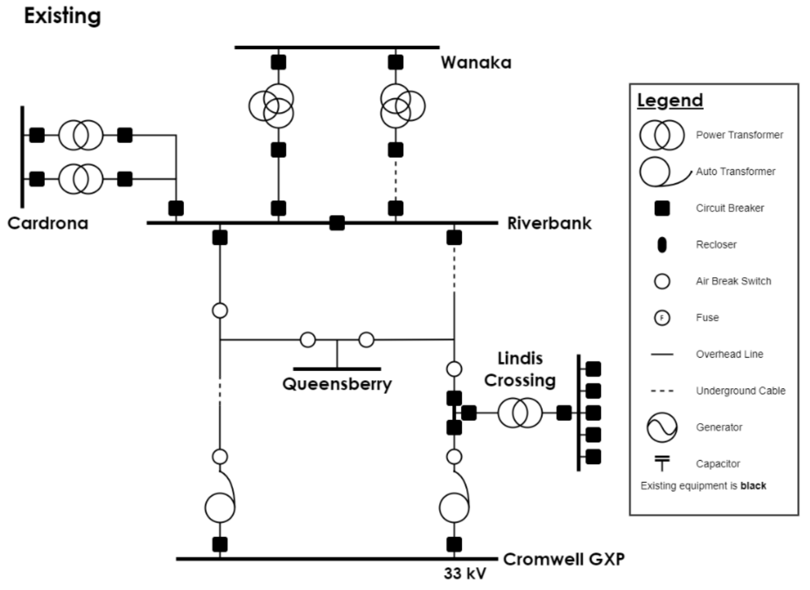


Table 17-13: New Upper Clutha 66 kV Line

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
New Upper Clutha 66 kV Line	Existing lines are anticipated to reach thermal and voltage constraints	• - Install a new 66 kV line from Meg-Cardrona and convert CML-Meg line as 66 kV • - New 66 kV line from CML GXP to CH substation and rebuild CH-RK to 66 kV • - upgrade existing 66 kV lines • - New 66 kV line from CML to RK • - New 110 kV from CML to CA	**Install a new 66 kV line from Meg-Cardrona and convert CML-Meg line as 66 kV** This solution provides the following benefits: • Significantly increases subtransmission capacity to the Upper Clutha region • Provides N-1 subtransmission security to Cardrona and the Meg Power Station	2025–29	40.7



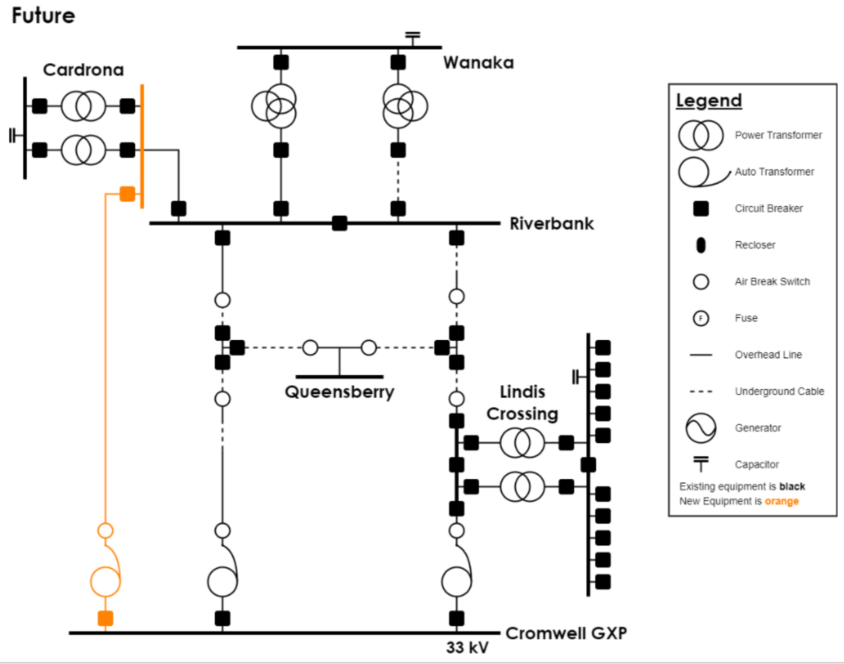
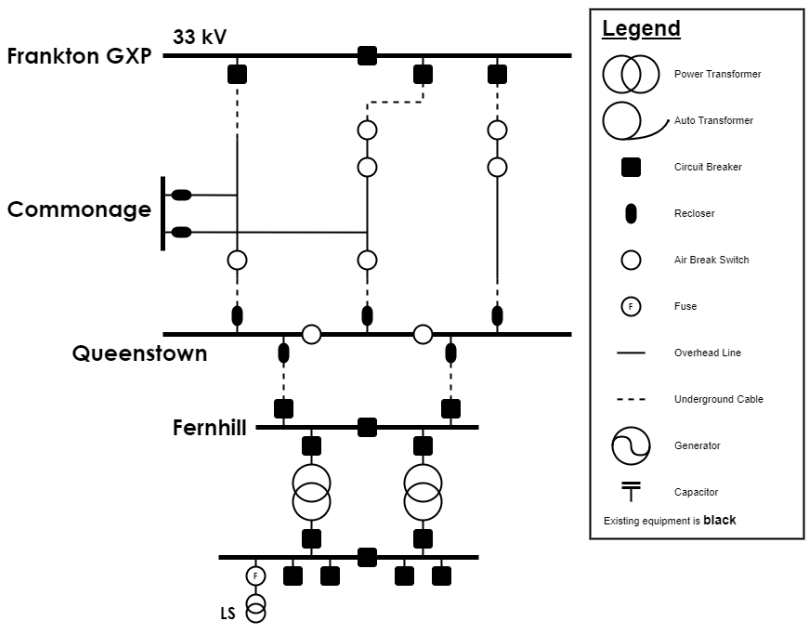


Table 17-14: Queenstown Subtransmission Capacity Upgrade

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	2028–29	4.3

Existing



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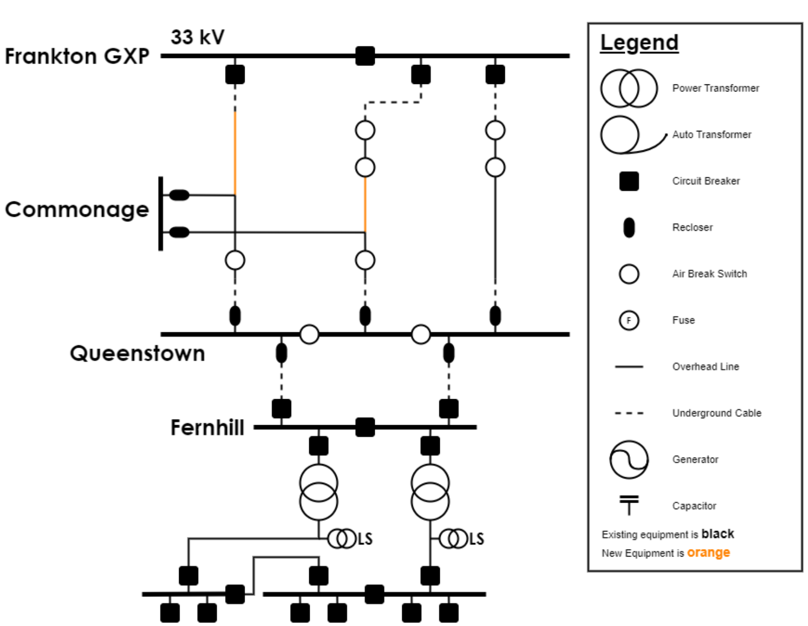
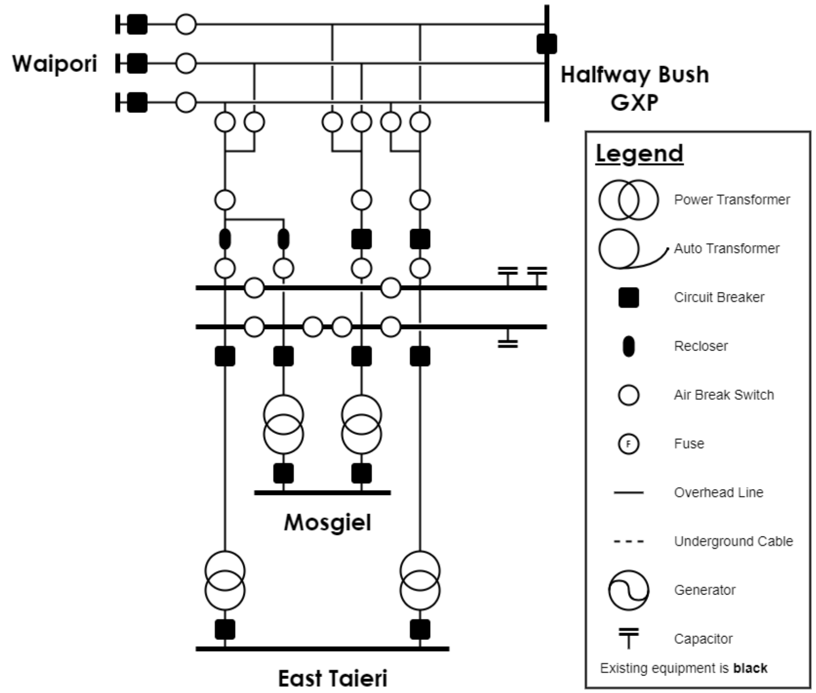


Table 17-15: Mosgiel Zone Substation Rebuild

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Mosgiel Zone Substation Rebuild	Growing load on Mosgiel and East Taieri Substations	• Do Nothing and accept load will exceed firm capacity • Rebuild Mosgiel substation	**Replace Existing Conductor from Frankton GXP to the Commonage Tee** This solution provides the following benefits: • Increases firm transmission capacity to meet growing load • Allows load From East Taieri to be transferred back to Mosgiel • Replaces equipment which will soon need to be replaced for ageing reasons • Allows 33 kV bus to be run closed avoiding the need for auto-changeover	2028–30	8.4

Existing



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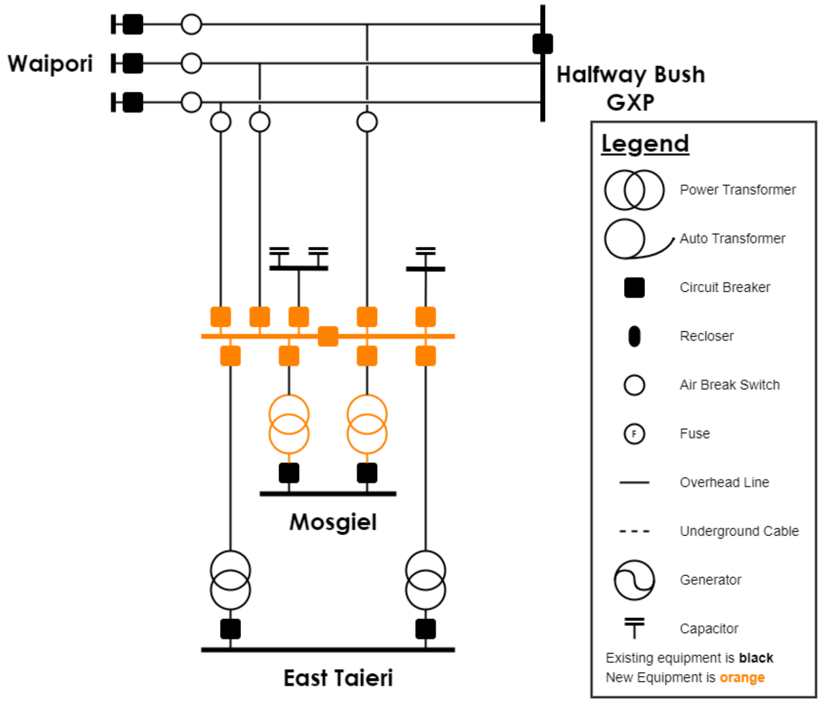


Table 17-16: Malaghans Road Subtransmission Upgrade

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	2029–30	4.2

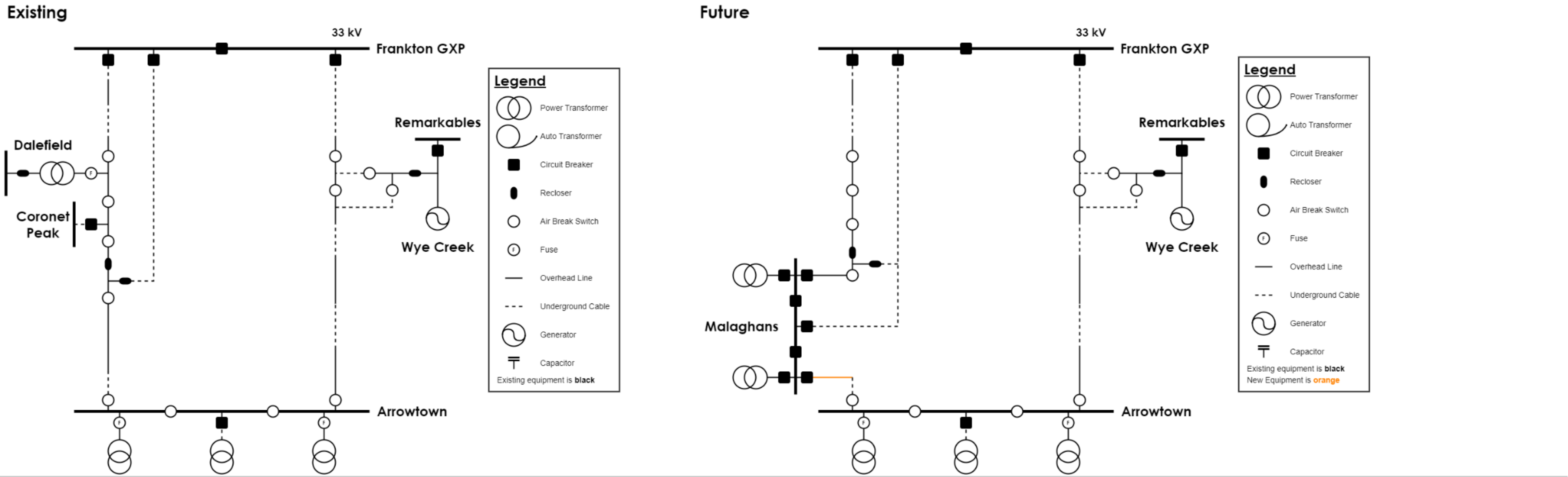


Table 17-17: Luggate Zone Substation

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Luggate Zone Substation	The growing load in the Upper Clutha area is becoming increasingly difficult to feed and maintain voltage under N-1 conditions Luggate area is growing and the film studio development will require capacity injection in the area	• Construct a new substation at Luggate • Install a larger transformer and additional feeders at Queensberry	**Construct a new substation at Luggate** This solution provides the following benefits: • Increases the substation capacity in the Queensberry - Luggate area • Provides some backup to the existing single transformer Queensberry substation • Improves distribution voltages by providing substation capacity at the Luggate load point • Makes use of surplus transformer from Lindis Crossing	2029–31	3.8

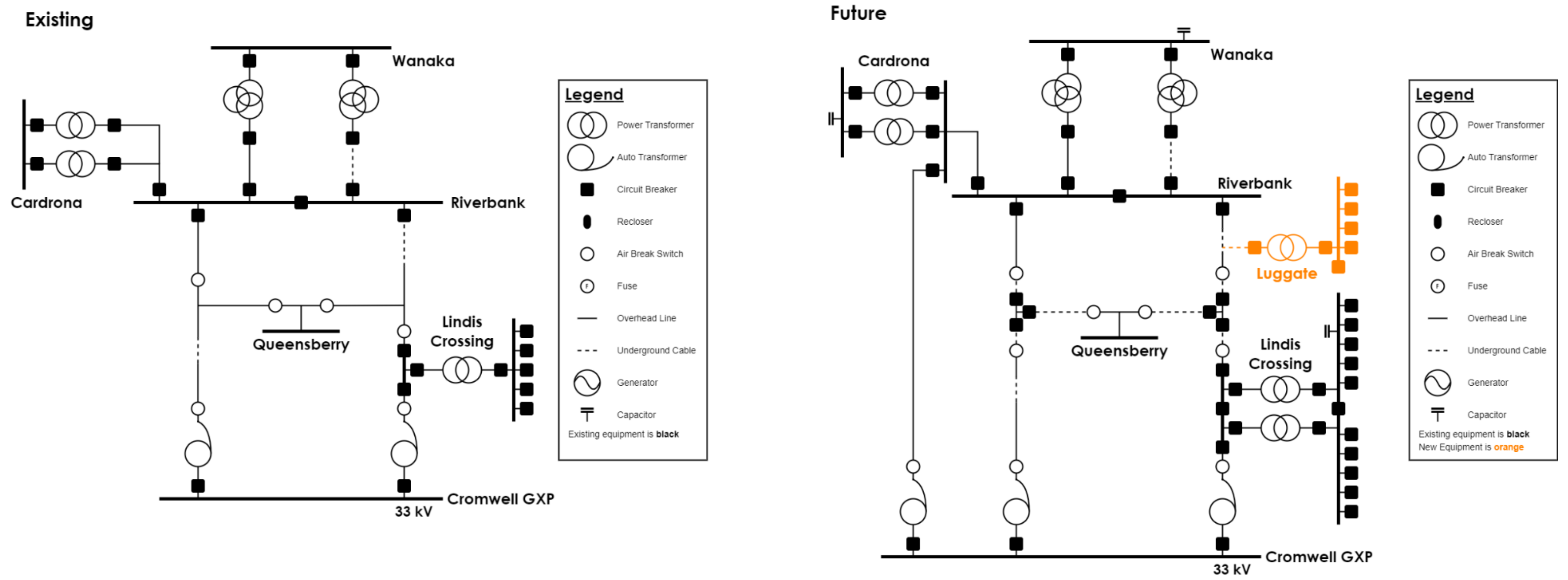
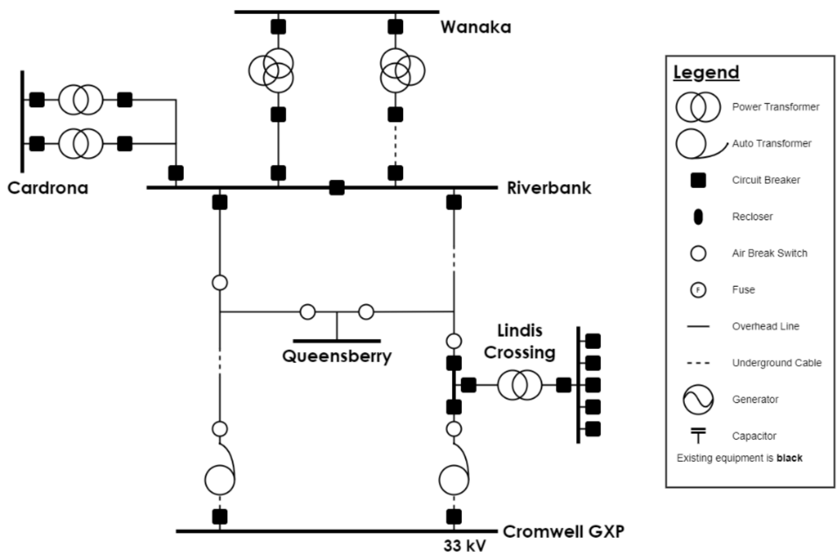


Table 17-18: Cardrona-Riverbank 66 kV New Line

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Cardrona-Riverbank 66 kV New Line	The existing Mink Cardrona-Riverbank 66 kV line limits the capacity that can be supplied by the new proposed Meg-Cardrona line	• Upgrade conductor on existing line • Construct new line	**Construct a new Cardrona-Riverbank 66 kV line** This solution provides the following benefits: • Increases the capacity that new 66 kV Meg-Cardrona line can supply to the Upper Clutha area • Reduces voltage drop and losses	2030–32	8.8

Existing



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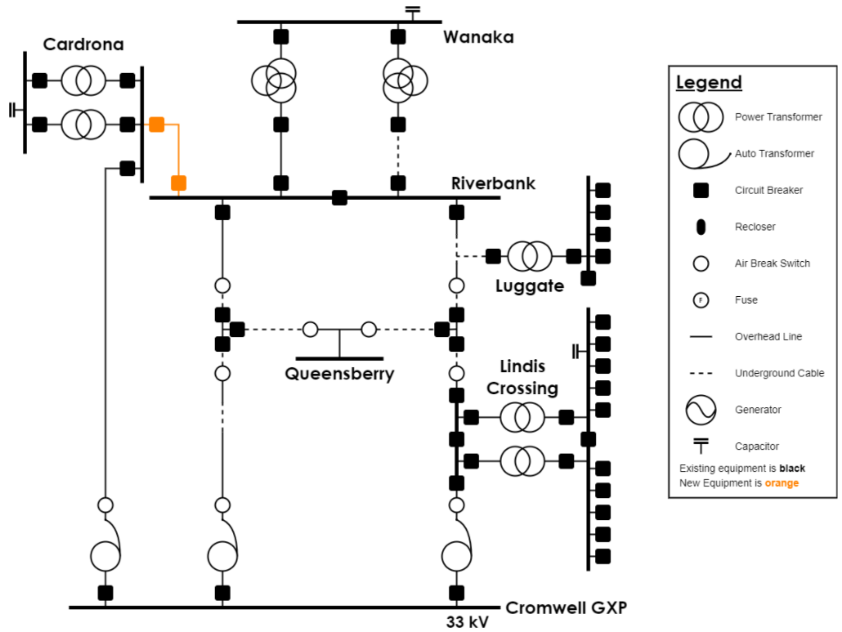


Table 17-19: Whitechapel Zone Substation (New Arrowtown)

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	2030–32	8.2

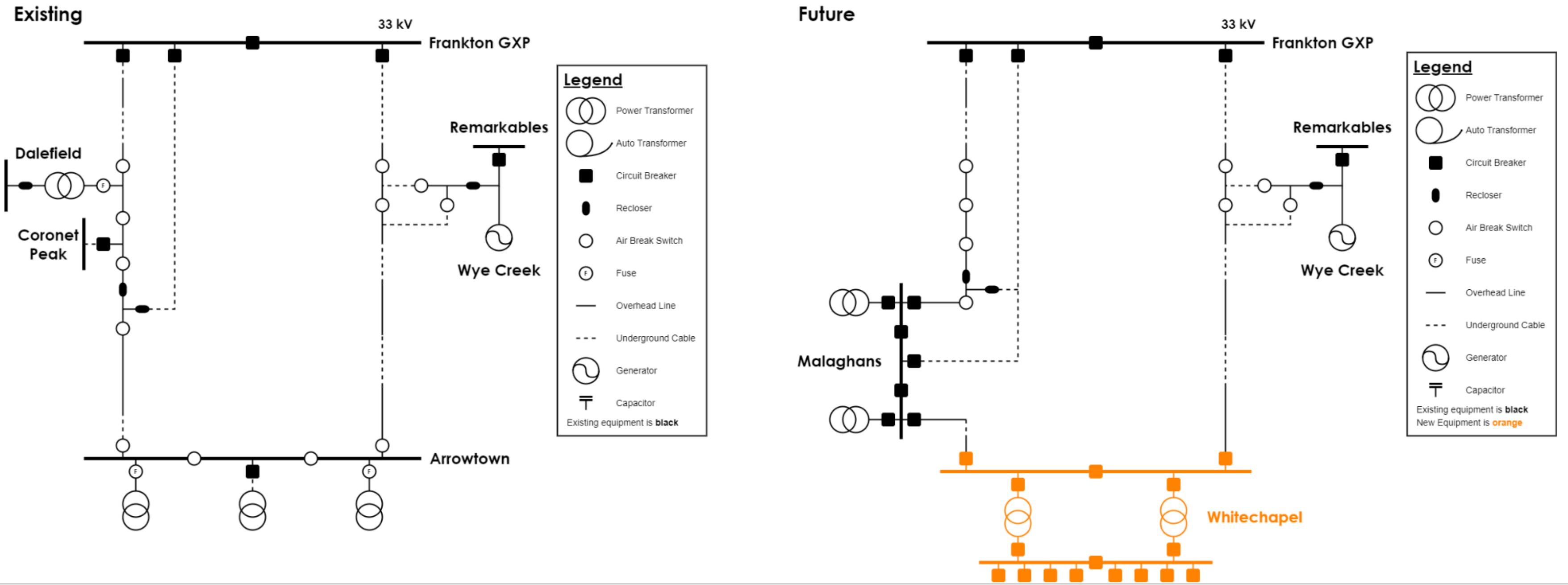
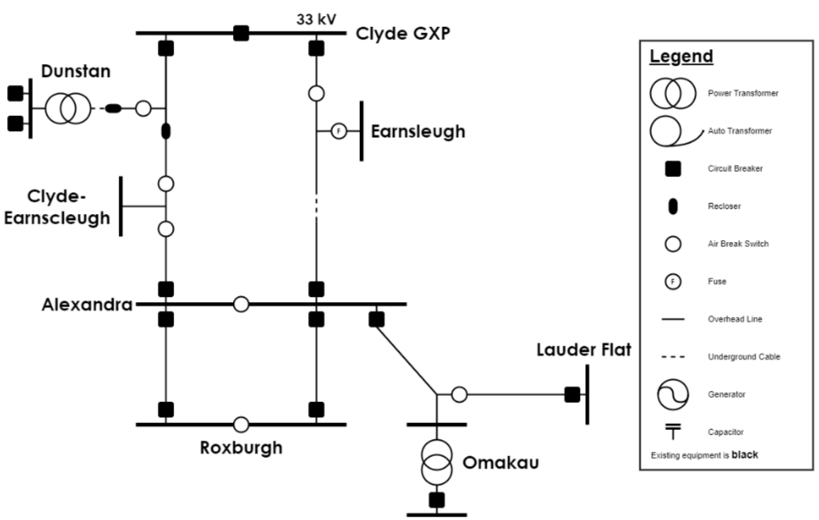


Table 17-20: Alexandra-Omakau New Subtransmission Line

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Alexandra-Omakau New Subtransmission Line	The growing irrigation load in the Omakau-Lauder Flat area is exceeding the thermal and voltage drop 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 conductor on existing line Construct a second Alexandra-Omakau 33 kV line	**Construct a second Alexandra-Omakau 33 kV line** This solution provides the following benefits: • Provides subtransmission capacity to meet growing load • Gives N-1 subtransmission option to allow supply to be maintained for outages outside of peak load times • Allows for future upgrade of existing line to give full N-1 subtransmission capacity		
			Stage 1 – To run in parallel with first half of existing line (mostly Squirrel Conductor)	2031–32	7.6
			Stage 2 – To complete the new line	2033–34	7.6

Existing



Future

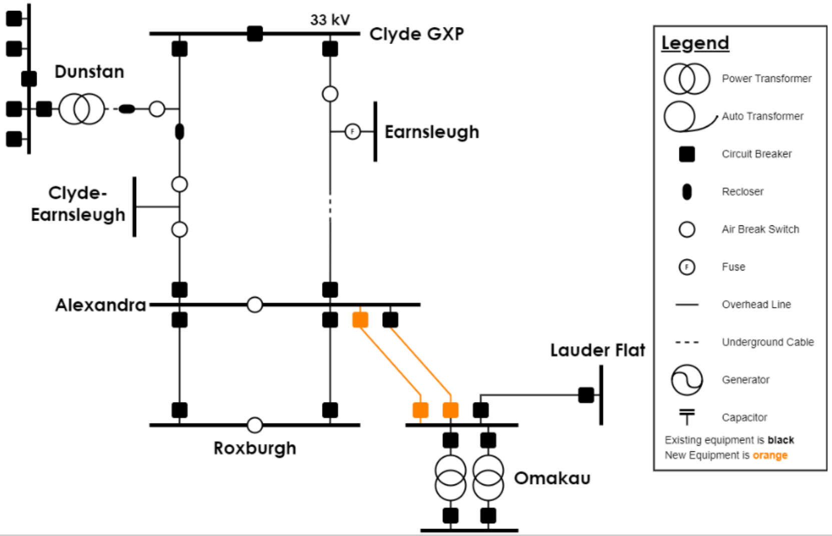
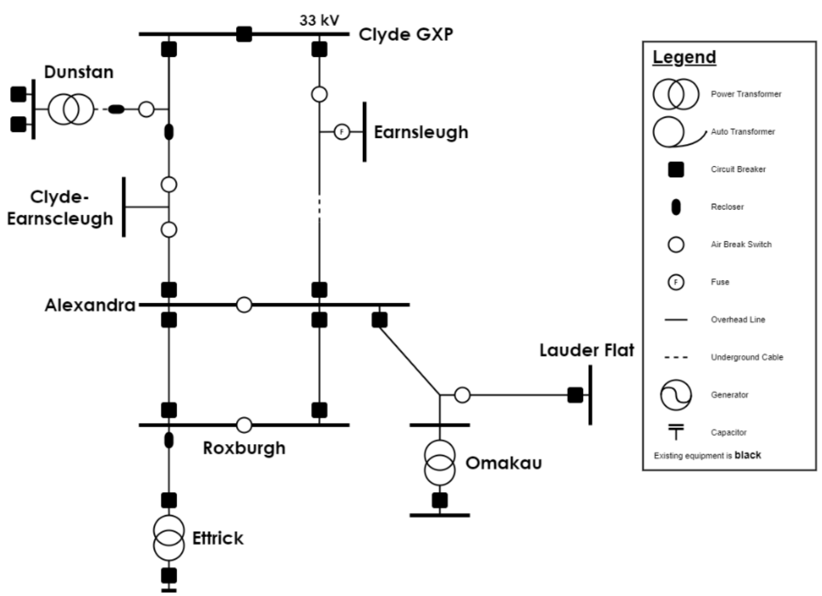


Table 17-21: Ettrick Zone Substation Upgrade

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	**Install larger transformer as part of rebuild project** 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	2013–33	5.3

Existing



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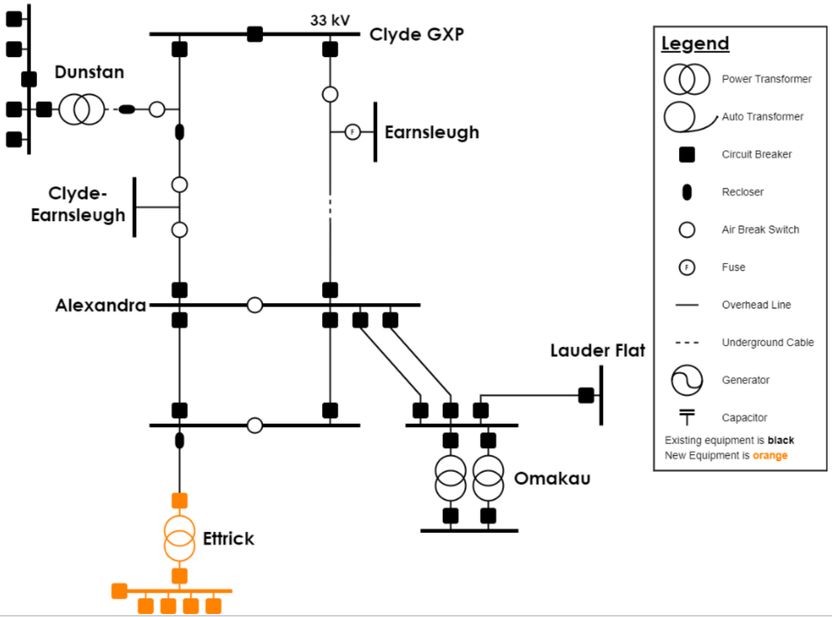
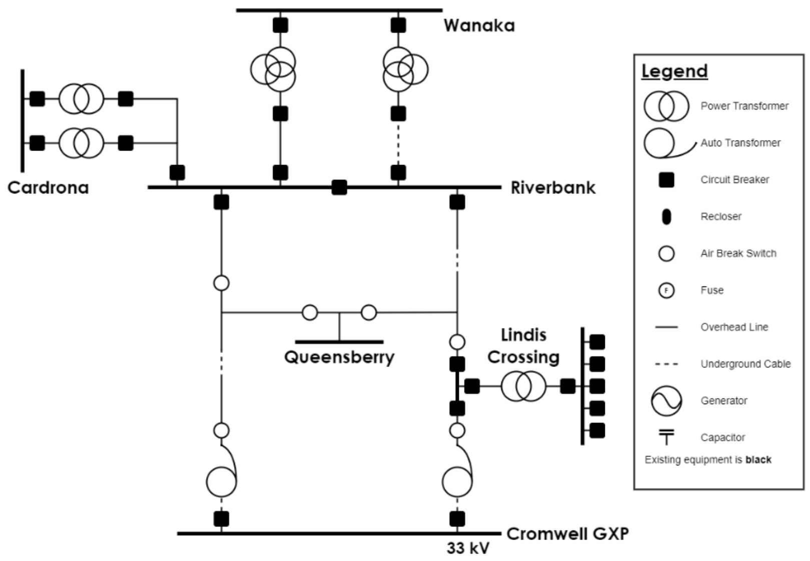


Table 17-22: Lindis Crossing Capacity Upgrade Stage 2

Project	Investment Need	Short list Options	Identified Solution and Benefits	Period	Capex ($m)
Lindis Crossing Capacity Upgrade Stage 2	Growing irrigation load in the Lindis Crossing and Queensberry areas will not be able to be fed if the new 24 MVA transformer (installed in stage 1) is out of service	• Replace original 7.5 MVA transformer at Lindis Crossing with 24 MVA transformer and replace original 11 kV switchgear • Install an additional transformer and switchgear at Queensberry	**Replace original 7.5 MVA transformer at Lindis Crossing with 24 MVA transformer and replace original 11kV switchgear** This solution provides the following benefits: • Upgrades Lindis Crossing to a full n-1 24 MVA substation • Frees up existing 7.5 MVA transformer for use elsewhere	2032–33	3.0

Existing



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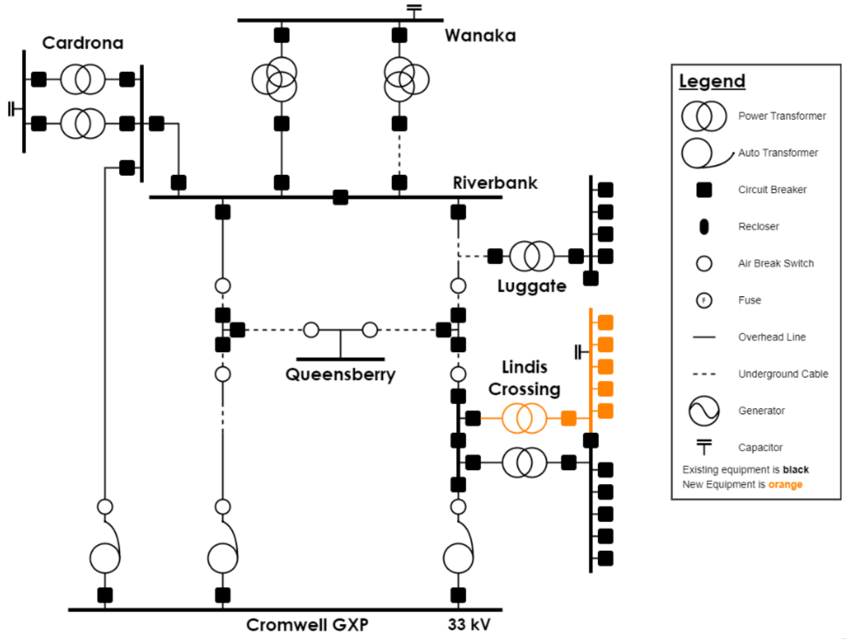
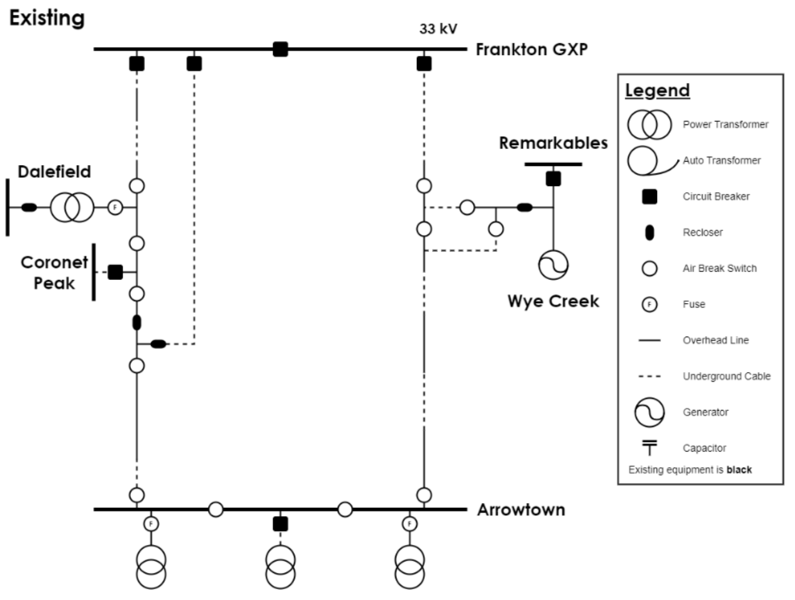
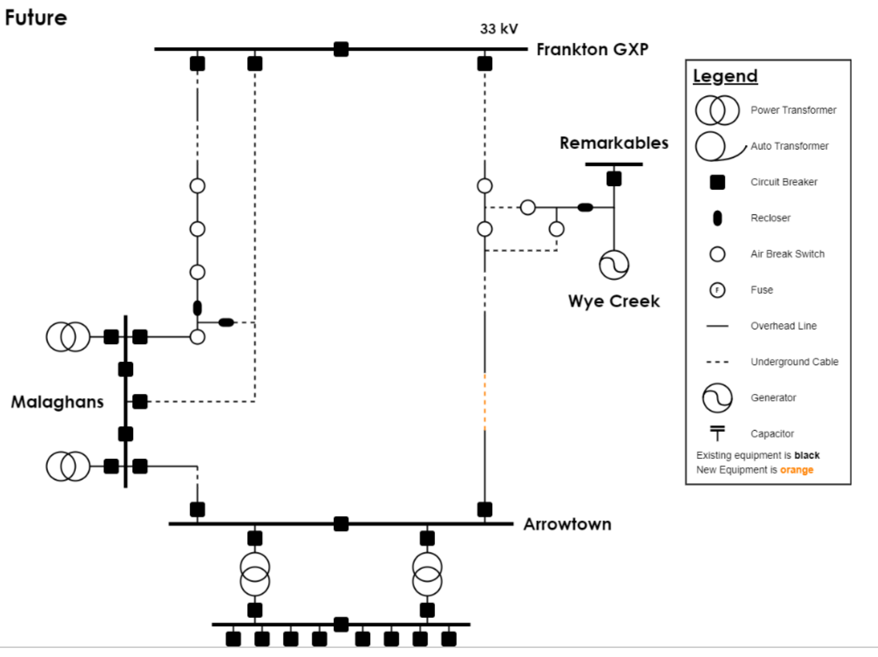


Table 17-23: Lake Hayes Subtransmission Cable Upgrade

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	2033–34	1.1





APPENDIX F: Preventive Maintenance Activities

Table 17-24 gives an overview of the preventive maintenance activities we carry out on our assets, and 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 17-24: 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
Clean dry-type cable terminations on RMUs and distribution transformers		10-yearly
Insulation resistance and polarisation index inspection		10-yearly
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		Annually
Oil Interceptor cleaning		Annually
Crane certifications		Annually
Petroblock replacement		6-yearly
Oil sensor functionality check		4-yearly

Painting		10-yearly
Power transformers		**Frequency**
Ground level inspection to identify apparent defects in 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
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; 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
Switchgear	**Activity**	**Frequency**
Indoor and outdoor	Visual inspection of circuit breakers including cyclometer readings	Monthly
Indoor and outdoor	Thermography, partial discharge and acoustic tests	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	Post fault maintenance	Operations based
Ancillary zone substation		**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 & testing		6-monthly
Fire Protection Inspection		Annually
Fire Protection Pressure Testing		5-yearly
Earth Grid Testing		5-yearly
Grounded mounted switchgear		**Frequency**
Visual inspection focusing on site conditions, site security, paint condition, corrosion, labels, earthing check, 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 Inspect task		2.5-yearly (only for units with circuit breaker

		functionality & fitted with protection)
Where possible to complete without an outage, exercise switches to prove functionality plus the Annual Inspect task		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 Inspect 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 enclosure		**Frequency**
LV enclosure inspection and minor repairs as/if required		6-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 substation		**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	To be determined
Ground mounted	Air filled cable box inspections and termination cleaning.	When RMUs co-located with ground-mounted transformers are inspected
Ground mounted	317 Hz ripple plant inspection and maintenance	Ad-hoc as required
Pole-mounted	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
Voltage regulators		**Frequency**
Visual inspection, thermographic testing, 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		4-6-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 G: 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	2025	10.0
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 a new indoor vacuum insulated switchgear.	2024	2026	5.3
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	3.8
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 and a new 24 MVA transformer.	2027	2028	3.4
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 24MVA transformers.	2028	2029	4.2
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 and the protection equipment which is electro-mechanical with performance issues and has reached the end of its serviceable life.	2029	2030	4.7
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.	2029	2030	8.8
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 considered to be approaching end-of-life and have performance issues.	2030	2031	9.4
Dunedin	Zone Substations	**South City 11 kV Switchboard Replacement** We will decommission the existing indoor 6.6kV oil insulated switchgear at end-of-life and replace with new indoor vacuum insulated switchgear.	2031	2032	4.9

Sub-network	Category	Major Renewal Projects	From	To	Capex ($m)
Dunedin	Zone Substations	**Corstorphine Transformer Replacement**	2032	2034	9.7
Dunedin	Zone Substations	**North East Valley 11 kV switchgear replacement** This project involves replacement of existing 11 kV indoor SF_6 switchgear and associated auxiliary systems that will be at end-of-life.	2034	2035	2.7
Dunedin	Subtransmission Cable Projects	**Kaikorai Valley PILC Cable Replacement**	2023	2026	4.9
Dunedin	Subtransmission Cable Projects	**Corstorphine Oil Cable Replacement**	2025	2030	10.4
Dunedin	Subtransmission Cable Projects	**Willowbank Gas Cable Replacement**	2029	2033	6.0
Dunedin	Subtransmission Conductor Projects	**Waipori Stages 2B – 6**	2024	2032	31.8
Central Otago	Zone Substations	**Alexandra 33 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	2025	8.0
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
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.	2031	2032	3.3
Queenstown	Zone Substations	**Remarkables T1 replacement** This project involves replacement of transformer and associated auxiliary equipment at end-of-life.	2032	2033	1.4

***Feasibility studies to better understand Subtransmission Cable Projects routes and subsequent costs are currently underway**

APPENDIX H: 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
	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
	3.6.4	how conflicting interests are managed;	Section 4.3
	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

Requirement			AMP reference
	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 13.3 Section 15.7
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
	(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

Requirement			AMP reference
			Section 6.5 Section 7.1 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
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 F
	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 D
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 15.7
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
Assets covered			
4		The AMP must provide details of the assets covered, including-	
4.1		a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	
	4.1.1	the region(s) covered;	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

Requirement			AMP reference
	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; and	Chapter 3
	4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Chapter 3 Section 11.9
4.3		If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Refer to 4.2 above
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

Requirement			AMP reference
	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
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 D
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.	Section 5.1 Appendix D
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 6.1, 6.5
	11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	

Requirement			AMP reference
	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;	Section 9.1 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 10.5, 10.6, 10.7
	11.8.3	identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Sections 10.5, 10.6, 10.7
	11.8.4	discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	Sections 9.1, 9.5 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;	Sections 9.1, 9.5 Sections 10.1, 10.2
	11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	Sections 9.5, 9.6 Sections 10.1, 10.2
	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 distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	

Requirement				AMP reference
		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 E
		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 E
		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 E
	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; and	Section 9.6
		11.12.2	the potential for non-network solutions to address network problems or constraints.	Section 9.6
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 F
		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 G

Requirement			AMP reference
	12.3.4	a summary of the projects planned for the following four years (where known); and	Appendix G
	12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	Appendix G
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
	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.	Section 6.5 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;	Section 9.6 Section 11.1

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—	

Requirement			AMP reference
	14.1	Methods, details and conclusions of risk analysis;	Sections 7.1, 7.2, 7.3
	14.2	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	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.	Sections 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
	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:	
		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

Requirement			AMP reference
			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 16.1
	17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections; and	Section 16.1
	17.4.4	commonly encountered delays and potential timeframes for different connections.	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
		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

Requirement			AMP reference
	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 I: 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, 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.

Stephen Richard Thompson

Janice Evelyn Fredric

27 March 2024

Date