Orion New Zealand Limited
Asset Management Plan

Asset Management Plan 2024

Cover: Touch footy players, Sally, Lara and Henry practicing at the Thomas Edmonds Band Rotunda illuminated with power delivered by Orion, on the banks of the Avon River, Cambridge Tce, Christchurch.

Tēnā koe

A lot has happened in the 12 months since our last Asset Management Plan.

In 2023 we put forward our best estimate of the direction and magnitude of the challenges and opportunities facing Orion to meet the new energy future. We signalled the significant increase in capital and operational expenditure needed to gear our network up for fundamental changes in how we power our community. Our position on that remains fundamentally unchanged – refined by deeper analysis of different possible scenarios, improved data to inform smart decision-making, and the benefit of time as our market evolves.

In this AMP we are forecasting total capex of $2.3b and $1.1b opex over the 10-year AMP planning period. Recognising the impact that cost increases have on our customers, we have refined our forecasts to a level below our 2023 AMP forecast. They remain at an unprecedented level of forecast expenditure for Orion.

Central Canterbury is one of Aotearoa New Zealand's fastest growing regions. These are challenging times for Orion, maintaining a safe, reliable and resilient network in the face of an energy revolution, strong residential growth, and persistent inflationary pressures. It is a challenge we are up for, but it is clear our current regulated line charge revenues will struggle to support sustainable growth and development of our network to keep pace with our community's needs.

We await the Commerce Commission's draft and final Default Price-quality Path (DPP) decisions for the five years starting 1 April 2025. We appreciate it is a challenge for the Commission as part of its pan-industry DPP decisions, to tailor to the unique circumstances of each business and the community they serve. While we are hopeful of a DPP decision that provides sufficient scope for investment and flexibility to adequately serve our customers and region – in the event it doesn't, we will consider applying to the Commerce Commission for a Customised Price-quality Path.

This AMP supports our region's continued success and creates the foundation for electricity to take an increasingly important role in our community's future.

Nāku noa, nā

Nigel Barbour
Orion Group Chief Executive

Orion

Liability disclaimer

This Asset Management Plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012.

Some of the information and statements contained in this AMP are comprised of, or are based on, assumptions, estimates, forecasts, predictions and projections made by Orion New Zealand Limited (Orion). In addition, some of the information and statements are based on actions that Orion currently intends to take in the future. Circumstances will change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Orion may at a later date decide to take different actions to those it currently intends to take.

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When considering the content of this AMP, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

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1 Executive summary

Photo: Network Access Manager, Peter Allen, and Head of Operations Stu Kilduff discussing key points in our AMP.

1. Introducing our 2024 Asset Management Plan

This Asset Management Plan (AMP) sets out our assessment of the challenges and opportunities presented to Orion by the evolving energy sector and our operating environment. It presents our expenditure plans to ensure we continue to meet the needs of our community. This AMP provides a summary of the key programmes of work we will undertake to maintain and develop our network along with our expenditure forecasts, for the next 10 years, from 1 April 2024.

2. Delivering a safe, reliable and resilient service, now and into the future

Our network plays a central role powering our community and enabling our customer's energy choices. To continue to serve our community well in this role now and into the future, it is important we invest prudently to manage safety risk, asset health, and available capacity on our network. It is vital we renew and maintain our assets, develop our network to keep pace with customer needs and evolving technology, while managing increasing cost pressures.

Orion has an uncompromising approach to safety and we are diligent in proactively managing safety risks for the public, our people, service providers and the environment. Managing critical safety risks is integral to how we plan and implement our work programmes, and in the day-to-day operation of our network.

We continue to experience strong demand growth In areas of our network, in particular Halswell and Rolleston. This growth is driven by new residential subdivisions, the shift to decarbonise process heat and the electrification of transport. Supporting population and business growth is a critical focus for Orion and fundamental to our role in the economic development of our region.

Aligned with asset management objectives, our investments over this AMP period have been developed to ensure our network and assets are:

- **Safe** – we are committed to good safety outcomes. We focus on managing the risks associated with our diverse range of assets and ensuring our interventions are targeted to assets that pose higher risk. For example, we are increasing our investment in replacing poles and switchgear.
- **Reliable** – reliable energy services are important to our customers, and they are generally happy with the levels of reliability they receive. However, the increasing incidence of climate change driven severe weather events increases the risk of more frequent and extended outages. This is particularly the case as assets age and their condition degrades. We are committed to ensuring we continue to deliver appropriate levels of reliability to customers during this 10-year AMP period.
- **Resilient** – in our latest customer engagements, both our urban and rural customers place a clear priority on Orion investing in the resilience of our network. Our investments in resilience will increase our network security and its ability to withstand more severe weather events due to climate change.

Our network plays a central role powering our community and enabling our customer's energy choices.

- **Flexible** – our customers' energy needs continue to evolve. We expect to see continued, strong growth in customers adopting technologies such as roof top solar generation and electric vehicles. We believe it is important Orion supports our customers in the energy choices they make. We are focused on ensuring Orion provides the network capacity and security needed, as well as building sufficient flexibility to accommodate new technologies to benefit our customers.

Our vision for the future is for Orion's electricity network to provide a safe, reliable and resilient link to existing energy sources and at the same time, to help our customers unlock more flexibility, innovative solutions, and cost-effective services.

Our investments in resilience will increase our network security and its ability to withstand more severe weather events due to climate change.

3. Changes in the energy environment

Several external factors continue to inform our forecasts and have influenced our development of this AMP. These include:

- Our material costs have increased far more than the average Consumer Price Index – particularly for programmes involving a high civil works component in the road corridor.
- The Selwyn District continues to grow strongly:
  - We continue to experience new customer connection growth at the high end of Stats NZ projections.
- Winter 2023 saw six of the 10 highest national electricity peaks on record. Three of Orion's 2023 winter peak demand days coincided with these national peak days.
- Cyclone Gabrielle:
  - Reinforced the value of resilience and heightened customers' support for this investment driver. The impact of the cyclone put an emphasis on the importance of network 'hardening' and redundancy at a sub-transmission, bulk supply, level.
  - Highlighted the value of mutual aid and collaboration amongst Electricity Distribution Businesses and emergency response agencies. Cyclone Gabrielle saw the Orion Group actively involved in power restoration efforts with Top Energy, Northpower and Powerco.

Our material costs have increased far more than the average Consumer Price Index.

- A change of Government and with it:
  - A change in policy settings around how we incentivise industry to decarbonise with more weight placed on price signalling via mechanisms such as the Emissions Trading Scheme (ETS); less weight on direct interventions / funding via mechanisms such as the Government Investment in Decarbonising Industry fund (GIDI).
  - The end of the Clean Car Discount scheme on 31 December 2023.
  - The termination of the Lake Onslow pumped hydro scheme.

4. Our investment strategy continues to evolve

During FY23 we worked to improve the accuracy and maturity of our investment forecasts. We spent more time engaging with stakeholders to better understand their needs and expectations. For example, we:

- **Engaged with the local authorities and economic development agencies** within our region to better understand their forecasts for population growth – a key driver of connection growth – and their priorities. We have reflected population growth higher than previously forecast in our investment plans / forecasts.
- **Collaborated on the preparation of the North Canterbury Regional Energy Transition Accelerator report** with the Energy Efficiency and Conservation Authority (EECA), consultants and customers. This report advances the work previously done by EECA and DETA Consulting on process heat demand. As a result, we have refined down our demand forecast for decarbonisation of process heat.

Based on this work, we have improved the accuracy and maturity of our forecasts. In this AMP we present our current, best estimate of the investments required over the next 10 years to provide the safe, reliable and resilient services our customers expect and to support our region's ambitions to decarbonise.

Taking into account all changes in our environment in 2023 and the insights we have gained from consultation has added greater depth to our understanding of what the future holds and resulted in a significant level of forecast expenditure over the next 10 years. We are forecasting total capital expenditure of $2.3b and operational expenditure of $1.1b over the 10-year period of this plan.

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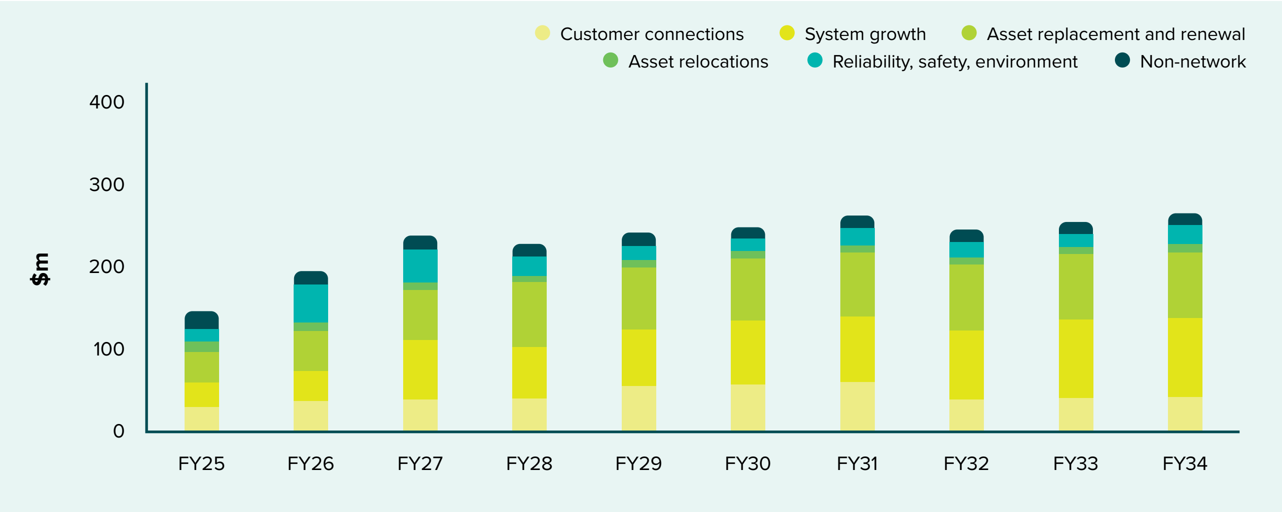
5. Capital expenditure

Our capital expenditure for this AMP planning period is set out in Figure 1.1. This level of investment is required to achieve our investment priorities and deliver a safe, reliable, and resilient service for the people and businesses of our region.

Figure 1.1 Total capital forecast (real)



The biggest drivers for our capital investment are:

- **Asset replacement and renewal** – over the next 10 years, our focus remains on replacing legacy assets installed during the 1960s to 1980s, ensuring the network's ongoing safety and reliability. We will also enhance network resilience by targeting poles in high wind zones which pose higher risk due to their design and construction not withstanding harsher environmental conditions because of climate change.
- **System growth** – this supports load growth in our region due to population increases and the transition to low carbon energy, for example, electric vehicle adoption.
- **Customer connections** – includes new residential connections due to population migration to our region and support for customers decarbonising their industrial and manufacturing heat processes.
- **Data and digitisation** – our Integrated Asset Management (IAM) programme is a key focus. It involves transforming our operating model, optimising our core workflows and shifting to a digitised, data-driven organisation. This includes the upgrade, development, replacement, introduction and integration of core platforms and services. By digitising our asset data, we improve our capacity to use condition and inspection results for more timely, better-informed, smart investment decisions.

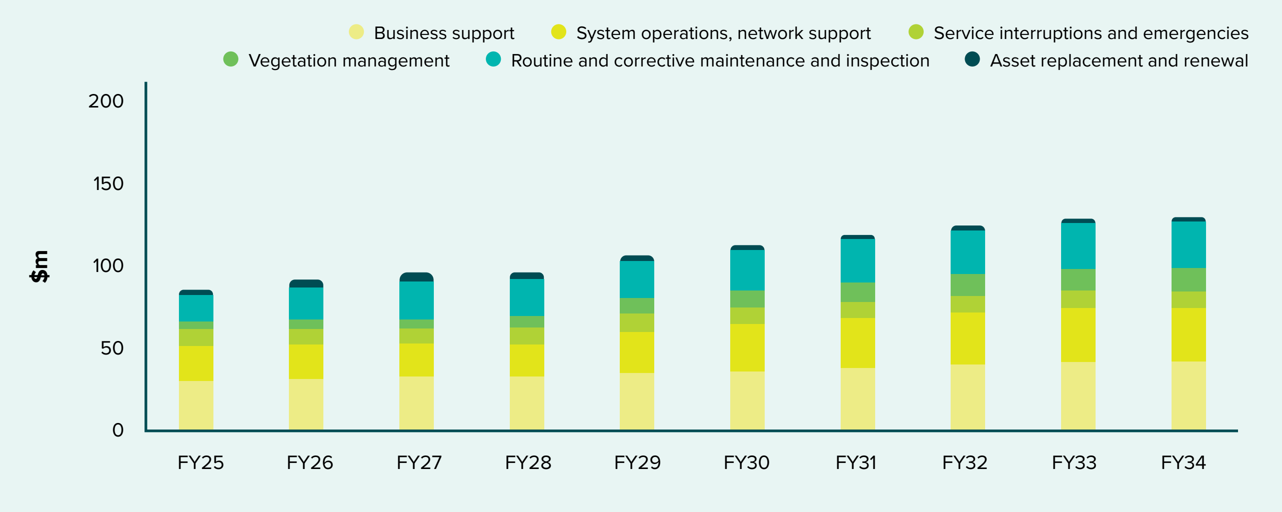
Increases in our forecast capital expenditure over this AMP period are largely due to growth works and new customer connections. Non-network investments are procured and delivered separately from our network investments and are managed directly with suppliers. Our renewal and our reliability, safety and environment programmes are broadly in-line with recently delivered volumes. Overall, based on our recent successful delivery of our 2023 capital investment programmes we are confident our governance and planning processes will ensure we continue to deliver our works programme in a safe and cost-effective manner.

By digitising our asset data, we improve our capacity to use condition and inspection results for more timely, better-informed, smart investment decisions.

6. Operational expenditure

Our operational expenditure for this AMP planning period is set out in Figure 1.2. This level of expenditure is required to deliver our operations and maintenance activities and ensure appropriate levels of support for our asset management activities.

Figure 1.2 Total operational forecast (real)



The biggest drivers for our operational investment are:

- **Vegetation management** – we will implement a data-driven, risk-based approach to prioritise vegetation trimming programmes to ensure a more effective targeting of high-risk areas. By doing so, we aim to minimise the number of outages and safety incidents caused by vegetation on overhead lines, particularly during severe weather events.
- **Routine and corrective maintenance and inspectio**n – while maintaining a consistent volume of maintenance and inspection activities, we are adjusting our expenditure over the 10-year period of this AMP to gather more comprehensive asset condition data for overhead conductors. As we found with our successful pole inspection methodology, acquiring better condition data is critical for deriving a risk-based replacement programme for our overhead conductors. This approach will give us confidence that we are replacing the correct conductors at the appropriate time. Not addressing end-of-life conductors in a timely manner can potentially compromise safety and reliability.
- **System operations and network support** – our commitment to Orion's Network Transformation Programme continues over the next decade to ensure our customers can take advantage of new low carbon technologies and we can maximise the two-way throughput of energy across our network. It is also enhancing the reliability and efficiency of our network design and operations while minimising disruptions. For example, we will enhance data analytics and network modelling capabilities to gain insights to support uptake of distributed energy resources. This will help optimise the lifespan and performance of our low voltage assets and increase our ability to roll-out proactive maintenance for them.

Our commitment to Orion's Network Transformation Programme continues over the next decade to ensure our customers can take advantage of new low carbon technologies and we can maximise the two-way throughput of energy across our network.

7. Potential need for a Customised Price-quality Path (CPP)

Our planned level of investment over the 10-year AMP period is a significant increase on current levels of expenditure and may be beyond what is allowed under the Commerce Commission's next five-year Default Price-quality Path (DPP) which will apply to most electricity distributors in New Zealand. This increase is needed for Orion to continue to deliver a long-term secure, reliable and resilient supply of energy for our customers – one that can meet their future needs. In addition to issues beyond our control such as the increasing cost of capital, this increase in investment will initially put some upward pressure on prices. Over the long term, increased investment in our region's energy infrastructure will help to reduce price pressure as new technology assists us to manage our network at a lower cost.

We are mindful of the potential pricing impacts on our customers which have informed our decision-making when finalising our 2024 AMP forecasts and remain a key focus. To cost-effectively deliver on our asset management objectives we will continue to improve our asset management capability and ensure we focus on those investments that deliver improved outcomes at an appropriate cost.

Given the enormous challenges and opportunities facing the energy sector, we have taken a long-term view of expenditure required to deliver network and customer needs, rather than constrain forecasts at current levels or within current regulatory allowances. Expenditure above our allowances during the new regulatory pricing period commencing on 1 April 2025 will attract significant Incremental Rolling Incentive Scheme (IRIS) financial penalties, further impacting on our ability to make required investments.

This highlights that there may be a material gap between what is required and what might be allowed under the coming DPP reset, effective from 1 April 2025. This gap could lead to expenditure allowances that are too low to:

- Maintain a safe, reliable and resilient network in the face of increasing demand.
- Deliver the services customers want.
- Meet primary and delegated legislative requirements.
- Ensure Orion can provide services that reflect good industry practice.

If the new DPP does not provide the level of expenditure we forecast is needed, Orion will have to look at other options. We may apply to the Commerce Commission for a CPP to reset Orion's regulated revenue allowances to a level that allows us to meet our customers' needs, legislative requirements and maintain good industry practice. For more discussion on this possibility, see Section 2.

A core element of our strategy is to engage effectively with our customers and the communities we serve. We will continue to prioritise this to ensure our expenditure decisions reflect the level of service they desire and at a cost they find acceptable. We will use the insights received from customers and other key stakeholders to inform and test our objectives and investment plans for a CPP proposal.

We may apply to the Commerce Commission for a CPP to reset Orion's regulated revenue allowances to a level that allows us to meet our customers' needs, legislative requirements and maintain good industry practice.

8. Overview of major projects

For a list of our key capital replacement programmes and our maintenance programmes and their alignment with Orion Group Strategy and our Asset Management Objectives, see Tables 1.1 and 1.2.

For a list of our top 10 network development base programmes and their alignment with Orion Group Strategy and our Asset Management Objectives, see Table 1.3.

Table 1.1 Capital replacement programmes and their Asset Management Objectives for FY25 to FY34

Orion Group Strategy:		Powering a cleaner and brighter future with our community								
		Facilitating decarbonisation and hosting capacity at lowest cost	**Investing to maintain our network**						**Being a force for good in the communities we serve, enabling the net zero transition**	
Asset class	Programme description	System growth	Safety	Reliability of supply and power quality	Security of supply	Operational efficiency	Resilience	Network readiness	Environmental sustainability	Customer experience
Overhead	Ongoing pole and conductor replacement, overhead to underground conversion and line switch replacement		**✓**	✓	✓		✓			
Switchgear	This asset class replacement is driven by condition and risk		**✓**	✓	✓	✓			✓	
Underground	Replacement of cables and link boxes e.g. supply fuse relocation programme to remove legacy issues		✓	✓	**✓**		✓	✓		
Secondary systems	Work includes relay replacement, radio upgrades and fibre installation between zone substations. LV correction equipment upgrade to improve power quality		**✓**	✓	✓			✓		
Transformers	Replacement of end-of-life power and distribution transformers		✓	**✓**	✓			✓		
Network property	Work includes kiosk and security fence upgrade, building security and integrity improvements etc.		✓		✓		**✓**			

Primary objective   Secondary objective

Table 1.2 Maintenance programmes and their Asset Management Objectives for FY25 to FY34

Orion Group Strategy:		Powering a cleaner and brighter future with our community								
		Facilitating decarbonisation and hosting capacity at lowest cost	**Investing to maintain our network**						**Being a force for good in the communities we serve, enabling the net zero transition**	
Asset class	Programme description	System growth	Safety	Reliability of supply and power quality	Security of supply	Operational efficiency	Resilience	Network readiness	Environmental sustainability	Customer experience
Overhead	Asset monitoring, inspections and maintenance. Emergency works		✓	✓	✓		✓			
Secondary systems	Asset monitoring, inspections and maintenance.		✓	✓	✓					
Primary plant	Replacement of cables and link boxes e.g. supply fuse relocation programme to remove legacy issues		✓	✓	✓		✓			
Power transformers	Work includes relay replacement, radio upgrades and fibre installation between zone substations. LV correction equipment upgrade to improve power quality		✓	✓	✓			✓		
Buildings, enclosures and grounds	Replacement of end of life power and distribution transformers		✓		✓			✓		

Primary objective

Secondary objective

Table 1.3 Top 10 network development base programmes and their Asset Management Objectives for FY25 to FY34

Orion Group Strategy:		Powering a cleaner and brighter future with our community								
		Facilitating decarbonisation and hosting capacity at lowest cost	Investing to maintain our network						Being a force for good in the communities we serve, enabling the net zero transition	
Programme	Years	System growth	Safety	Reliability of supply and power quality	Security of supply	Operational efficiency	Resilience	Network readiness	Environmental sustainability	Customer experience
Region A 66kV subtransmission resilience	FY23 - 35	✓ Secondary			✓ Secondary		✓ Primary	✓ Secondary		
Southwest Christchurch and surrounding areas' growth and resilience	FY26 - 34	✓ Secondary			✓ Primary		✓ Secondary		✓ Secondary	
Northern Christchurch security of supply	FY26 - 35				✓ Primary		✓ Secondary			
Rolleston area capacity and security	FY24 - 33	✓ Secondary			✓ Primary					
Hororata GXP capacity and security	FY29 - 33	✓ Secondary		✓ Secondary	✓ Primary			✓ Secondary		
Lincoln capacity and security	FY24 - 33	✓ Primary			✓ Secondary					
Region B 66kV subtransmission capacity and security	FY23 - 28	✓ Secondary			✓ Primary			✓ Secondary	✓ Secondary	
Other HV projects	FY25 - 34	✓ Primary		✓ Secondary	✓ Secondary					
400V LV monitoring	FY20 - 26	✓ Primary		✓ Secondary						
Proactive 400V LV reinforcement	FY25 - 34	✓ Primary			✓ Secondary			✓ Secondary	✓ Secondary	

Primary objective   Secondary objective

AMP section summary

This Asset Management Plan is divided into 10 Sections which cover:

Section 1: Executive summary

Our executive summary provides an overview of what is driving investment in our network. Here we reflect on the recent changes in Orion's environment, outline the key influences and major factors and programmes of work that guide our approach to managing our assets for the next 10 years.

Section 2: Our strategy

In this section we outline the Orion Group Strategy, our analysis of the factors influencing our future asset planning, and our exploration of various possible future scenarios. We also outline our asset management framework, policy, and the processes involved in developing our AMP.

Section 3: Customer and performance

In this section we focus on our engagement with our customers. We describe the different channels we use to engage with these key stakeholders, what they are telling us, and how they rate our performance. The section also sets out the performance measures and targets we set ourselves, and those set for us by the Commerce Commission, and how we perform against those targets.

Section 4: People and technology

In this section we describe the work of our people and our information systems. We set out how we are planning to meet the workforce needs of the future, outline the teams within Orion and their key functions, and describe the systems that support the operation of our business.

Section 5: Managing risk

This section sets out our approach to managing the risks facing our business, and the diligence with which we approach risk management. We identify what our key risks are and how we go about risk identification, evaluation and treatment of these risks.

Section 6: Our planning approach

This section sets out Orion's Asset Management Strategy and provides an overview of our network and how we evaluate different options to address the constraints we are forecasting. The section sets out our processes for prioritising our projects, and how we are transforming our network using non-traditional approaches and innovation.

Section 7: Managing our assets

Here we provide an overview of each of our 18 asset classes; and outline an assessment of their asset health along with our maintenance and replacement plans for each one.

Section 8: Developing our network

In this section we set out how we are developing our network to respond to the growing needs of our region and the opportunities presented by the transition to low carbon energy. This section describes the major investments we plan to make in our high voltage (HV) and low voltage (LV) network over the next 10 years.

Section 9: How we deliver

This section describes our approach to addressing our future workforce resourcing and capability needs, at Orion and sector level. It sets out the key philosophies, policies and processes that enable us to deliver our works programme and AMP objectives, and our approach to managing the factors impacting delivery of our programme of work.

Section 10: Financial tables

Here we set out our key forecasts for expenditure for the next 10 years, based on programmes and projects detailed in Sections 7 and 8. In summary form, we set out our capital and operational expenditure for our network, and the business, annually from FY25 to FY34.

If you would like to know more about our approach to managing our assets and our plans for the next 10 years, please contact us on 0800 363 9898, or by email at info@oriongroup.co.nz.

2

Our strategy

Photo: Network Development Manager Craig Wong in a planning session with the Network Transformation and Investment team.

Contents

2.1 Introduction

In this section we describe the context in which Orion operates and how it shapes our investments through the 10-year period of this Asset Management Plan (AMP).

We also outline our asset management framework, policy, and the processes involved in developing our AMP. Our aim is to provide customers and other key stakeholders with an understanding of Orion's approach to the management of our assets and how we make our strategic and tactical decisions.

2.2 Orion today

Orion owns and operates the electricity distribution infrastructure in Central Canterbury including Ōtautahi Christchurch city and Selwyn District. Our network is both rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia River in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 224,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB). Orion has a fully owned subsidiary, industry service provider Connetics, and together with Orion the two organisations make up the Orion Group.

Central Canterbury is experiencing rapid population growth, with Christchurch and surrounding townships the centre of this dynamic region and main business hub of the South Island. One of the crucial services that underpins the well-being and prosperity of the people and businesses in this area is safe, reliable and resilient electricity distribution.

2.3 Our changing environment

Orion faces a rapidly changing energy environment in the decades ahead. Along with Aotearoa New Zealand's other electricity distributors, Orion has a key role to play in enabling decarbonisation and the electrification of the economy in service of New Zealand's target for net zero greenhouse gas emissions by 2050.

The requirements and drivers for Orion are not the same as those for other distributors. Different regions in New Zealand vary significantly in many ways:

- geography
- weather patterns and climate change, for example temperatures, incidence of serve weather events
- demographics, for example population growth and trends
- economic / planning imperatives such as housing intensification
- community needs for amenities, for example housing
- the energy transitions already experienced such as the switch to electricity for water and space heating
- how much latent capacity is available

This means each electricity distribution network in New Zealand is unique and requires their own, individual investment strategy. Some will need to invest more in high voltage systems, some more in low voltage, and some, like Orion, in both. Differing investment in data and digitisation of network management systems will also be needed. Opportunities to utilise customer load flexibility will also vary from network to network. As a result, each New Zealand electricity distribution network will require different strategies and differ in the timing of investment.

In the following sections we set out how these factors influence our investment decisions.

Each electricity distribution network in New Zealand is unique and requires their own, individual investment strategy.

Our Purpose is to power a cleaner and brighter future with our community

2.4 Orion Group Purpose and Strategy

The Orion Group is committed to powering a future where our community thrives within a resilient, low-carbon economy. Our Group Purpose, "Powering a cleaner and brighter future with our community," reflects our dedication to regional prosperity, achieved by striking a balance between energy affordability, reliability, resilience, and sustainability.

The Orion Group Strategy is an integral part of our daily dialogue and planning. While its influence extends beyond our AMP, it fundamentally drives our network development, maintenance programmes, and our vision for the future. Our overarching goal is to ensure we are not only supporting growth in our region but also supporting our community in its transition to a low-carbon economy. As much as decarbonisation is a driver of our network investment strategy we also take into account our region's strong population growth, and our customers' priority for increased network resilience.

Our overarching goal is to ensure we are not only supporting growth in our region but also supporting our community in its transition to a low-carbon economy.

Figure 2.4.1 Group Strategy framework

Purpose	Powering a cleaner and brighter future with our community				
Impact	Driving prosperity for our region through balancing energy affordability, energy security and sustainability				
Focus Areas	Facilitating decarbonisation and hosting capacity at lowest cost	Investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost	Being a force for good in the community we serve, enabling the net zero transition	Creating the preferred workplace	Fit for purpose capital structure

Our AMP is central to Orion achieving its strategic goals over the next five years, and in particular, delivering in two Focus Areas:

- Facilitating decarbonisation and hosting capacity at lowest cost.
- Investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost, enabling the net zero transition.

To achieve our goals in these two Focus Areas, we will drive our costs down in four key ways:

- **Creating a more highly utilised network** – particularly at the low voltage level where our aim is to enable customer participation, facilitate people and businesses that both consume and produce energy, use new technology and information to make as much as we can out of the existing network without having to invest more.
- **Implementing a more efficient and effective works management system** – based on using new technology and digitisation, we will streamline processes, and enhance overall productivity, ultimately leading to a more streamlined and responsive works management system.
- **Using real time data and new technology** – such as drones to locate faults by flying over overhead lines instead of relying solely on manual patrols by operators. This minimises outage duration and guarantees the absence of debris on the line, ensuring safe power restoration.
- **Optimal timing of asset renewals** – through improved monitoring and assessment processes and digitised asset information we will, over time, reduce lifecycle capital and operational expenditure.

In the next section, we explain how Orion reflects various external drivers and environmental changes in our scenario modelling, and how that shapes investment set out in this AMP.

2.4.1 Future energy scenarios

We have developed five different possible scenarios for how the energy environment might evolve. By modelling these different pathways, we have developed a deeper understanding of the potential range of outcomes, and the drivers or inflection points for any shift between pathways.

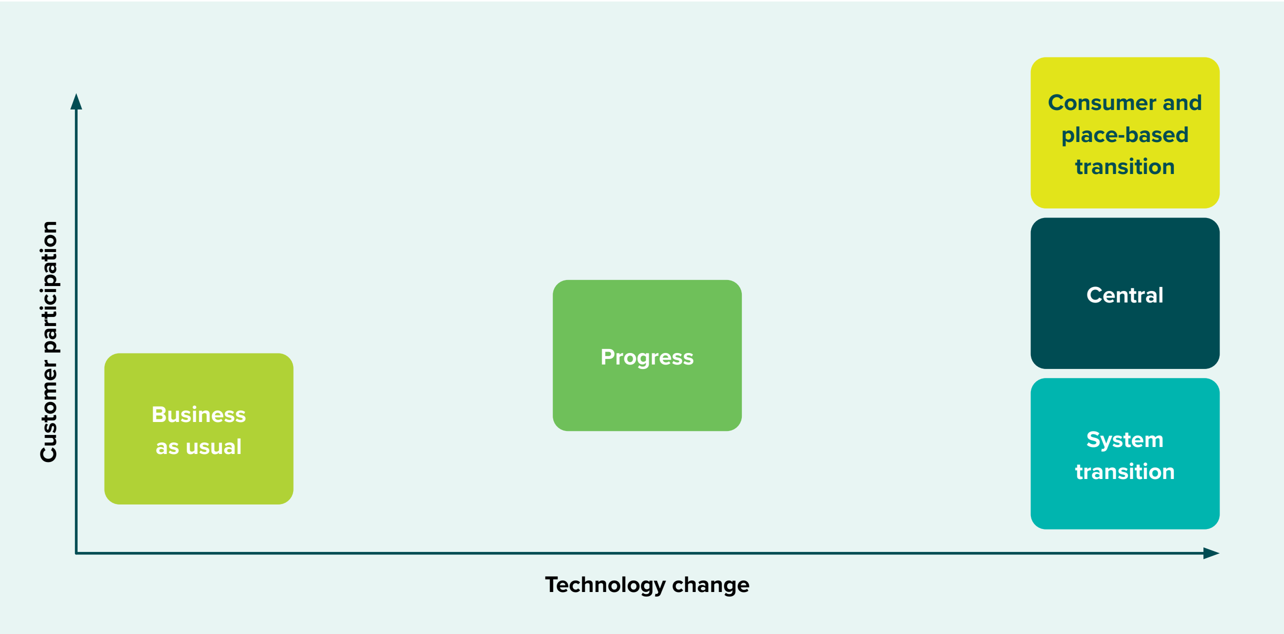
Our five future energy scenarios describe plausible futures in 2050, and the pathways for reaching those futures. We developed our scenarios by identifying key drivers of uncertainty and placing them on different axes. These drivers are technology change and customer participation in the energy system. Other factors beyond these two key drivers such as economic and population growth are also considered in the development of the scenarios.

Our five scenarios are:

- **Business as usual** – an extrapolation of existing electrification trends, in a low growth world. Low change in technological uptake results in low economic growth and high climate change impact.
- **Progress** – where electrification and change in consumer behavior accelerates but does not result in full transition of the energy sector by 2050. There is some increased uptake of new technology and optimisation, with medium economic and population growth.
- **System transition** – a centrally led transition of the energy sector, achieved through high uptake of new technology, but minimal shift in consumer engagement. Economic growth and population growth are medium. Climate change impacts are towards best case scenarios.
- **Consumer and place-based transition** – where consumer and place-based optimisation combined with technology change achieves energy sector transition. High levels of network optimisation can be achieved through optimisation and place-based optimisation leads to more efficient building and urban transport. Climate change impacts are towards best case scenarios.
- **Central scenario** – medium growth in the Orion region and accelerating electrification closer to 2035. The scenario assumes some optimisation of charging demand and place-based optimisation but low levels of EDB controlled flexibility. Climate change impacts are towards best case scenarios.

For our five different scenarios and their position by 2050 in relation to the key drivers of uncertainty – technology change and customer participation – see Figure 2.4.2.

Figure 2.4.2 Orion's Future Energy Scenarios in relation to the key drivers of uncertainty



We have chosen the Central Scenario as the basis for Orion's asset management planning. This scenario fits with our best view of load growth over the next 10 years based on recent experience and current trends.

The Central Scenario also provides Orion with a least regrets approach to making tactical investments in response to the high levels of uncertainty in the energy transition.

It provides Orion with a pathway that provides us with the flexibility to cost-effectively respond to change, by pivoting to reflect altered circumstances, if needed.

We have chosen the Central Scenario as the basis for Orion's asset management planning.

2.4.2 External drivers of network investment

This section outlines the Central Scenario further by setting out the 10 drivers of change we have considered, our assumptions and their impact on investment over the AMP planning period.

2.4.2.1 Population and residential growth

- **Driver of change** – population growth is a key driver impacting energy usage and network investments. Christchurch city and Selwyn District have experienced significant growth since the 2010-2011 earthquakes, with Selwyn seeing a 30% increase in population the last five years. At the higher end of their projections, Stats NZ projects substantial growth by 2050, introducing uncertainty in high, medium, and low scenarios. This projection takes into account factors such as increased net migration, higher living costs driving internal migration, and general regional growth.
- **Assumption** – that forecast population growth leans towards the medium side of projections for Christchurch city and the high side for Selwyn District. We also assume the proposed Mass Rapid Transit system will start impacting housing development and transport options from 2030, aligning with building growth projections by Christchurch City Council. While this has a small estimated impact of around 5MW in peak load demand by FY34, higher growth is anticipated in later years.
- **Impact on investment** – under the Central Scenario, anticipated population and residential development growth are expected to contribute significantly to peak demand, estimated at 70MW by FY34. Our planning approach centers on expanding greenfield housing and will monitor the growth with in-fill housing. For how this driver affects network peak demand see Section 8.

Under the Central Scenario, anticipated population and residential development growth are expected to contribute significantly to peak demand, estimated at 70MW by FY34.

2.4.2.2 Industrial and commercial growth

- **Driver of change** – the expected growth in the overall economy and population expansion are expected to influence industrial and commercial growth. This will fuel electricity demand growth in industrial and commercial sectors due to new businesses, sector expansions, and the electrification of existing industry. Electrification of process heat has a substantial impact on peak demand, and is addressed separately, see 2.4.2.5.
- **Assumption** – Christchurch City Council and Selwyn District Council's long term plans will play a vital role in determining the impact of load growth from industrial and commercial sectors on our network. Broader economic growth will also exert influence on Orion.
- **Impact on investment** – it is estimated that industrial and commercial growth will contribute an additional 12MW to the overall network peak demand by FY34.

2.4.2.3 Electrification of gas

- **Driver of change** – Central Canterbury has a low number of reticulated gas connections compared to other regions which face a significant impact from phasing out of gas for space heating. However, the prevalent use of bottled gas for water and space heating and cooking in our region indicates we may see impacts from the Government's plan for the gas industry's transition to a low emissions future. Domestic 45kg LPG sales exhibit an annual increase of 3-5%, while bulk LPG sales are stabilising.
- **Assumption** – the possible timeline for phasing out natural gas hinges on factors such as price, the emissions trading scheme, and Government interventions. Electrification may drive this phase-out and impact network demand. Alternatively, if consumers prefer gas for certain applications, the development of biogas markets might cater to this preference.
- **Impact on investment** – under the Central Scenario we have assumed rapid phase-out of both residential and commercial gas. We have included the consequent impacts on network peak demand in the 'population and residential' and 'industrial and commercial' growth amounts.

2.4.2.4 Electrification of transport

- **Driver of change** – the shift toward electrification of transport is set to drive the adoption of electric vehicles (EVs) across light, medium, and heavy vehicle categories. Each vehicle type will exert a distinct impact on electricity demand. Private light vehicles are expected to contribute significantly to the rise in household electricity demand up to 2050. This will affect both our 400V low voltage network at the street level and the high voltage network. The pathway for decarbonising heavy vehicles is less certain, with electrification and alternative options such as hydrogen being tested and likely to become viable in the near future.

Private light vehicles are expected to contribute significantly to the rise in household electricity demand up to 2050.

- **Assumption** – the timing and location of private EV charging play an important role in influencing network peaks. In our Central Scenario we assume EV charging demand can largely be shifted to off-peak at night. Our approach to time-of-use pricing can incentivise this shift, but it is likely to need further incentive from retailers and information for EV owners to allow this to happen. The rate of uptake in different suburbs on our network could be highly variable, and our early observations are suburbs with a medium income have a higher rate of EV uptake.
- **Impact on investment** – for our 2023 AMP we used Ministry of Transport potential EV uptake figures as a baseline. This assumes ~16% of the region's vehicle fleet will be electric in 10 years with 20% charging at peak times. We have since revised our expenditure forecast to assume a lower proportion of EVs charging at peak times. The ongoing electrification of transportation is expected to add an extra 28MW to the overall network peak demand by FY34 under the Central Scenario.

  Despite the expectation of higher EV uptake, while noting the end of the Clean Car Discount scheme on 31 December 2023 has currently dampened EV sales, we are projecting a reduced percentage of EV charging during peak times. This is based on our efforts to incentivise a behavioral shift among EV users, intending to influence their charging habits by altering our time-of-use pricing strategies. This approach encourages charging during off-peak hours, ultimately contributing to more efficient use of resources and better network management.

2.4.2.5 Electrification of process heat

- **Driver of change** – the phase-out of coal and fossil fuel boilers by 2037 will lead to increasing electricity demand from industrial users in our region. In collaboration with partners, local industry studies and direct conversations with customers have indicated industry conversion from the use of fossil fuels to electrification of process heat will substantially increase our current maximum peak demand. The extent and timing of this additional load is uncertain due to factors such as the availability and cost of biomass and the potential impact of government investment or regulations on the speed of these conversions.
- **Assumption** – our assumption of electricity demand from conversion to electrification of process heat is based on the Regional Energy Transition Accelerator (RETA) North Canterbury report published in 2023 which studied the potential for conversions in our regions. We have also assumed some biomass will be economically available and used by Central Canterbury industry as it converts from coal-fired boilers.
- **Impact on investment** – electrification of process heat is expected to contribute significantly to network peak demand, estimated at 81MW by FY34 under the Central Scenario. We will continue to engage with customers to understand their decarbonisation pathways and will update our forecasts and network development plans as their plans develop.

Electrification of process heat is expected to contribute significantly to network peak demand, estimated at 81MW by FY34 under the Central Scenario.

2.4.2.6 Load management

- **Driver of change** – Orion has a history of effectively managing peak loading to ensure the efficient operation of our network and prevent the need for immediate and costly reinforcement of transmission and distribution networks. Currently, our primary method for implementing load management on the network involves the use of ripple relays. We rely on ripple control technology for load management in two key ways: peak load control for hot water heating; and fixed-time control for water and night store heating.
- **Assumption** – in our Central Scenario, we assume a medium reduction in hot water management over the AMP planning period.
- **Impact on investment** – in our most recent scenario modeling, projections indicate that the impact of third parties controlling hot water cylinders during peak network demand periods will be modest with a potential impact of ~6MW by FY34. Given the relatively minor nature of this potential loss, we have not designated a specific capital expenditure line item to address the impact.

The evolving landscape of battery technology, marked by decreasing costs and technological improvements, is a key driver of change.

2.4.2.7 Battery storage and vehicle-to-grid (V2G)

- **Driver of change** – the evolving landscape of battery technology, marked by decreasing costs and technological improvements, is a key driver of change. The potential integration of V2G technology is another factor we consider under our Central Scenario.
- **Assumption** – while current battery costs may hinder widespread residential battery deployment, some providers are bundling batteries with solar systems to enhance their value. The future optimisation of these technologies and potential conflicts with network needs remain uncertain.
- **Impact on investment** – for the planning period, we are assuming a medium battery and V2G uptake in the Central Scenario. This results in a reduction of 2MW in the total network peak demand by FY34.

2.4.2.8 Solar

- **Driver of change** – the growing interest and applications for utility-scale solar and wind generation connections to the Orion network underscore the transformative shift towards decarbonising energy use in our region. The steady rise in residential solar connections is being driven by factors including decreasing installation costs, rising grid electricity prices, and an increased consumer appreciation for energy resilience.
- **Assumption** – the future trajectory of distributed generation, including residential solar, hinges on various utilisation models such as self-consumption, power purchase agreements, and aggregation into virtual power plants. How these models align supply with local demand will dictate network impacts. The integration of non-grid power sources may introduce voltage and demand fluctuations, particularly during intermittent generation caused by factors such as cloud cover.
- **Impact on investment** – our Central Scenario estimates a 19MW reduction in network peak demand due to high solar uptake by FY34. We plan to address potential challenges such as voltage fluctuations through LV network optimisation and power electronic solutions.

2.4.2.9 Climate change

- **Driver of change** – climate change will increase wear and tear on our network assets, increase the incidence of damage from severe weather events, alter urban landscapes due to flood risk and rising sea levels, and modify asset performance while elevating fire risk due to rising air temperatures. Nationally, we are seeing significant impacts from climate change increasing the severity and frequency of storms.
- **Assumption** – in Canterbury, climate change is expected to increase annual mean wind speed, predominantly in inland areas. High wind speeds during extreme weather events can lead to customer outages, often caused by airborne debris or vegetation colliding with our lines. NIWA projections suggest a higher probability of wind speeds exceeding 50km/h in inland areas, particularly in the latter half of this century. Increased westerly winds, historically more damaging to our network, are expected. Orion's network area is likely to experience hotter, windier summers and wetter winters, with intensified rainfall events, elevating flood risk. This necessitates a strong focus on adaptation planning and network resilience.
- **Impact on investment** – to enhance the resilience of our overhead inland network to mitigate the impacts of climate change, strategic investment measures will be implemented over the AMP planning period. For example, we are targeting replacement of poles at higher altitudes in the Alpine and Banks Peninsular areas to mitigate potential damage from climate-induced weather events. We are also conducting risk-based assessment to prioritise our vegetation management programme more effectively. For further details on our pole replacement and vegetation management programmes, see Section 7.

To enhance the resilience of our overhead inland network to mitigate the impacts of climate change, strategic investment measures will be implemented over the AMP planning period.

2.4.2.10 Cost inflation

- **Driver of change** – inflation in materials costs has been higher than historically forecast. Significant contributors were COVID-19 and supply chain issues in general, unfavourable changes in commodity prices and exchange rates, geopolitical unrest, and greater demand world-wide from the electricity sector for materials and labour given the growing rate of decarbonisation and electrification.
- **Assumption** – historically, we assumed cost increases would be in line with general inflation forecasts. Based on this assumption, we used a combination of Consumer Price Index (CPI), Producers Price Index (PPI) and Labour Cost Index (LCI) forecasts to forecast the nominal dollar spend in each of the ten years of our AMP. However, it has become increasingly apparent that cost increases for materials in the energy sector have been significantly greater than general inflation indicators.

  Future trends suggest that ongoing decarbonisation and electrification are likely to contribute to a rise in material costs. We foresee a global surge in demand for electrical materials and labour, creating sustained pressure on prices as demand exceeds supply. Given Orion is a relatively small player in the global electrical materials market, we lack the purchasing power to mitigate rising costs. Consequently, we anticipate enduring materials and labour inflation in our local industry, surpassing PPI and LCI index levels in the upcoming years.
- **Impact on investment** – in this AMP we have moved away from assuming our nominal costs will increase in line with general inflationary factors and have assumed our network costs will increase at a greater rate. We have produced our AMP assumed inflators as the basis to determine the nominal dollar spend we will incur in each of the ten years forecast, and then discounted these nominal dollar figures by general inflation to arrive at the real dollar expenditure figures, in mid FY24 terms, shown throughout this AMP. For further information on the inflators used, see Appendix F.

  Over the coming year, we will further strengthen our ability to forecast future cost pressures by continuing to analyse invoices and by engaging local and international economic experts and other EBDs to seek their opinions on how electrification is likely to impact resources and costs.

We foresee a global surge in demand for electrical materials and labour, creating sustained pressure on prices as demand exceeds supply.

2.4.3 Navigating cost challenges in the regulatory setting

To address the cost challenges and undertake the network transformation required to meet the future needs of our customers, our expenditure forecasts are significantly higher for the Commerce Commission's next five-year Default Price-quality Path (DPP) is compared to the DPP we are currently operating under.

Given the uplift in our forecast expenditure we are concerned the DPP determination due late in 2024 will set regulated revenue expenditure allowances at a level that is insufficient for us to meet our community's future network needs.

While Orion is currently investing more than its current regulatory period (DPP3) regulated revenue expenditure allowances and incurring material IRIS incentive penalties, in the current period these are balanced out by other inflation adjustment mechanisms. However, as we look ahead to the next regulatory control period (DPP4) these inflation adjustment mechanisms are unlikely to apply and any investment above regulated revenue expenditure allowances, will attract significant IRIS incentive penalties. Given Orion is community owned by the Christchurch City Council and the Selwyn District Council, this incentive penalty reduces funding available for further investment or a reasonable return to shareholders for investment in the community.

We are undertaking initial planning to prepare an application for a Customised Price-quality Path (CPP). A key decision point for us to decide whether the DPP is sufficient will be when the draft DPP decision is released in May of this year.

A critical concern for us is how the DPP caters for investments required to support electrification and growing demand on our network and the level of investment needed to drive efficiencies into our business, and continuing to provide a safe, reliable and resilient network. We will be paying particular attention to the regulated revenue expenditure allowances and mechanisms which the Commission sets for:

- Process heat customers switching to electricity that are less than 5MW in size. Orion has 30 of these customers of which EECA estimates 60MW will convert in this AMP planning period.
- The Alpine Fault resilience investments that Orion has been undertaking to improve the resilience of Orion's network to earthquakes.
- Addressing the impacts of cost inflation and cost escalation on capital expenditure.
- Setting appropriate levels of operating expenditure.

Orion appreciates the Commerce Commission has a considerable and important task ahead in developing the next DPP and we encourage the Commission to look at solutions that we highlight in our submissions.

Given the uplift in our forecast expenditure we are concerned the DPP determination due late in 2024 will set regulated revenue expenditure allowances at a level that is insufficient for us to meet our community's future network needs.

2.5 Significant business assumptions

2.5.1 Business structure

We assume no major changes in the asset base through merger, changes of ownership and/or requirements of stakeholders.

2.5.2 Risk management

Our assumptions about management of risk are largely discussed in Section 5. Although we have planned for processes and resources to ensure business continuity because of a major event or equipment failure, we have not included the actual consequences of a forecast or hypothetical major event in our AMP forecasts.

2.5.3 Service level targets

We have based our service level targets on customers' views about the quality of service they expect. Extensive consultation over many years tells us that customers want us to deliver network reliability and resilience and keep prices down. To meet this expectation, we look for the right balance between costs for customers and network investment. For a summary of our recent customer engagement and their views, see Section 3. Future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure to ensure cost-effective delivery of network services.

2.5.4 Lifecycle management of our assets

We have assumed no significant purchase/sale of network assets from Transpower or other EDBs or forced disconnection of uneconomic supplies other than those discussed in the development of our network, see Section 7 and 8. The planned maintenance and replacement of our assets is largely condition and risk based. This assumes prudent risk management practices associated with good industry practice to achieve the outcomes in line with our targeted service levels.

2.5.5 Potential differences between our forecast and actual outcomes

Factors that may lead to material differences include:

- Regulatory requirements may change.
- Customer demand may change and/or the requirement for network resilience/reliability could change. This could be driven by national policy, economic and/or technology changes. This could lead to different levels of network investment.
- Changes in demand and/or connection growth could lead us to change the amount of and timing of our network projects.
- One or more un-forecast large energy customers/ generators may connect to our network requiring specific network development projects.
- Major equipment failure, a major natural disaster or a cyber-attack may impact our network, requiring significant response and recovery work. This may delay some planned projects during the period until the network is fully restored.
- Input costs and exchange rates and the cost of borrowing may vary, influencing the financeability associated with some projects. If higher costs are anticipated, some projects may be abandoned, delayed or substituted. See Section 2.4.2.10 on cost inflation.
- Changes to industry standards including additional legislative changes, e.g., traffic management, inspection equipment technologies and understanding of equipment failure mechanisms may lead to changing asset service specifications.
- Other factors discussed elsewhere in this AMP.

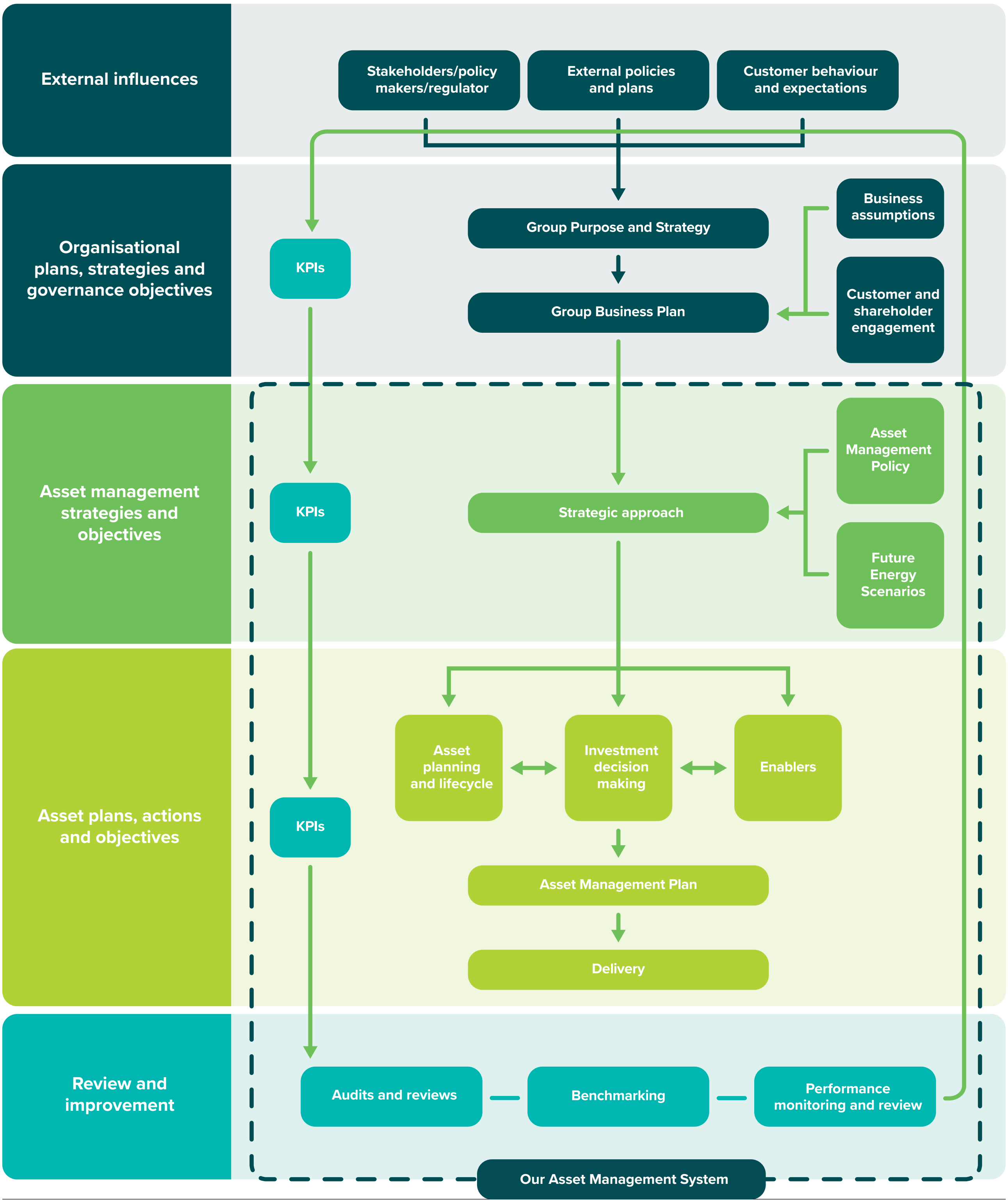
2.6 Asset Management Framework

Our Asset Management Framework ensures our asset management activities effectively support delivery of the Orion Group Strategy and are aligned to good practice asset management. The framework identifies the relationship between different processes, documents, plans and policies of the Asset Management System.

It provides structure and processes to ensure that:

- Our decisions, plans, and actions are in alignment with our Purpose, our Strategy, our asset management policy and the performance targets and key initiatives of Group Business Plan.
- We deliver our services with the required level of safety and reliability to meet our service obligations and resilience to respond to high-impact events.

Figure 2.6.1 Orion asset management framework



2.7 Asset Management System

Orion's Asset Management System (AMS) is an interconnected network of processes, policies, and strategies, developed to optimise the performance of our asset base and deliver the best possible service to our customers. It is underpinned by our strategic approach, asset planning and lifecycle management, robust decision-making, key enablers, our Asset Management Plan, delivery mechanisms, and continuous performance improvements.

2.7.1 Asset Management Policy

Our Asset Management Policy requires that we use good asset management practices to deliver on our Purpose and Group Strategy. We are committed to regular reviews of our processes and systems to ensure continuous improvement. Our Asset Management Policy is a set of guiding principles that direct our asset management activities. These principles are listed in Figure 2.7.1.

Figure 2.7.1 The 10 principles guiding our Asset Management Policy

1	Asset management decisions prioritise **safety** for our people, service providers and the public
2	**Risks** are identified, assessed, and managed in compliance with the Orion Group risk management framework
3	Asset management **decisions** are aligned with the **Orion Group's Purpose, Impact and Focus Areas**
4	**Stakeholders** are consulted to ensure investments align with future customer, community and other stakeholder needs and expectations; deliver required service levels, and meet Orion's Group strategic objectives
5	Asset management decisions are **data-driven** to optimise the delivery of stakeholder requirements at the lowest lifecycle cost
6	We maintain and enhance our asset management **capability** by recruiting, developing, and retaining great people
7	We continuously search for and implement opportunities to **innovate** and improve our asset management capability, efficiency, and effectiveness
8	All asset management activities **comply** with relevant laws, regulatory requirements, and company policies
9	We consider **future challenges**, technological advancements, and changing demands in asset management
10	We are commited to ensuring the **sustainability** of assets throughout their lifecycle, including consideration for recycling, repurposing, or decommissioning

Implementation of Policy

This AMP sets out how we implement this Policy by describing:

- How our AMP fits within our wider governance, Group Strategy and planning practices.
- How we engage with our customers to give them a voice in our decision making.
- Our target service levels.
- Our evaluation of our past performance.
- Our asset management practices – how we propose to maintain and replace our critical network assets over time.
- Our network development plans – how we propose to meet changing demands on our network over time.
- A picture of each asset class, its health, and maintenance and replacement plans.
- The team structure and resources we have in place to deliver our plan.
- Our 10-year expenditure forecasts – capital and operating.

Policy review

Every two years we review our Asset Management Policy to assess its effectiveness and relevance, making adjustments as necessary to meet evolving needs and goals of Orion and its stakeholders. Our leadership team and relevant subject matter experts review our AMP annually and review planned projects and expenditure forecasts. Our AMP steering group provides a further review before it is presented to the board for approval.

2.7.2 Our strategic approach

We bring together a range of strategies that work collectively to create a comprehensive, integrated approach to managing our assets to deliver on our business objectives. These strategies are informed by our Asset Management Policy and our Energy Future Scenarios. This integrated approach encourages collaborative and cross-functional decision-making, insight and information sharing, and supports best practice asset management.

2.7.2.1 Asset Management Strategy

Our Asset Management Strategy translates the Orion Group Strategy into asset management objectives. We measure our progress towards these objectives to ensure we are moving in the right direction and effectively contributing towards organisational goals. Our Asset Management Strategy is the core of Orion's approach to managing our assets. It informs our approach to the lifecycle management of our assets and enables strategic, informed decision-making. The implementation of this strategy is reflected in our core asset management objectives described in Section 2.8.

2.7.2.2 Operational asset management strategies

In response to the dynamic factors shaping our environment and investment landscape, we also have adopted operational asset management strategies, including:

- **Keep up with growth** – to address population growth and housing intensification, we will reinforce supply in constrained areas only after all options have been explored.
- **Just-in-time approach** – to facilitate industrial and commercial electrification, we will engage with industrial and commercial customers to ensure lowest the cost solution is adopted when needed and not before.
- **Lower demand** – to support transport electrification, our focus is on encouraging customers to charge off-peak and utilise flexibility solutions and new technology.
- **Release network capacity** – we will use data, digitisation and technology to release currently inaccessible, latent network capacity.
- **Grid stability assurance** – in relation to solar or other utility-scale generation, we will invest and monitor network impact to ensure network stability. For example, we will invest in enhancing grid monitoring and control capabilities to accommodate the dynamic nature of distributed energy resources, enabling adjustments to power flow, response to fluctuations, and optimisation of grid performance.
- **Climate change adaptation** – we will proactively address climate change risks, and we are committed to investments that effectively mitigate the challenges and opportunities posed by changing climate conditions.

We will use data, digitisation and technology to release currently inaccessible, latent network capacity.

2.7.2.3 Supporting strategies and roadmaps

We have devised a set of supporting strategies and roadmaps to complement our core and operational asset management strategies. These are:

- **Network Transformation Roadmap** – provides essential foresight and guidance as we adapt and evolve our electricity network to meet future demand.
- **Capital Investment Structure Policy and Pricing Strategy** – these work hand in hand when it comes to financial commitments and resource allocation. Our Capital Investment Structure Policy outlines how we balance investment in maintaining existing assets and making wise investments in new ones, while our Pricing Strategy ensures the cost of these decisions is recovered in a fair and transparent manner from customers. Our Pricing Strategy is available on our website.
- **Risk Management Strategy** – forms a protective layer over our operations, offering systematic methodologies for identifying, assessing, and mitigating potential risks.
- **Innovation Strategy** – uses the intersection of intelligence, curiosity and execution to provide the structure needed to rapidly explore and learn. An overview of this strategy is available on our website.
- **People Strategy** – the essential role of our workforce in realising our goals cannot be overstated. Our People Strategy ensures our team has the necessary skills, motivation and resources to implement our strategies effectively. It focuses on building a skilled, engaged, and resilient workforce capable of delivering our ambitious asset management agenda.

2.7.2.4 Strategies in development

Strategies in development are:

- **Sustainability Strategy** – underlines our commitment to environmental stewardship and sustainable practices in our asset management, ensuring a resilient future for our operations and communities.
- **Stakeholder Engagement Strategy** – it is essential we understand and consider the perspectives and expectations of our key stakeholders in our decision-making process. This engagement helps us align our asset management strategies with the needs and priorities of our stakeholders, promoting mutual trust and understanding.
- **Asset Information and Spatial Strategy** – fortifies our strategic decisions, underlining the critical role of data management in informing and enhancing our asset-related actions and decision-making.
- **Delivery Strategy** – all these strategies ultimately come together in our Delivery Strategy. This operational facet of our strategic system focuses on the implementation of decisions and plans derived from the interplay of all our strategies. It underlines our commitment to turning strategic intent into operational reality, ensuring our strategies are translated into actions that deliver tangible results.
- **Flexibility and Market Development Strategy** – Orion's emerging flexibility and market development strategy aims to support consumer and stakeholder participation in demand-side flexibility solutions, driven by the transition to net-zero emissions and the integration of renewables.

2.7.3 Asset planning and lifecycle management

At the heart of our Asset Management Strategy is an in-depth understanding of our assets throughout their lifecycle. We adopt comprehensive asset planning methodologies such as Condition Based Risk Management (CBRM), which consider factors such as health, criticality, performance and risks to inform our prioritisation, planning and decision making. See Section 6.

2.7.4 Investment decision-making

Critical to our Asset Management Strategy is a robust and transparent investment decision-making process. We consider a range of factors including those identified in our Future Energy Scenario work, system growth, network readiness, sustainability, deliverability, safety, and operational efficiency. By adopting a risk-based approach, we optimise the value of investments to enhance the performance, resilience and longevity of our assets. Our investment decisions are also guided by our investment framework which outlines the different processes for approval and business cases. See Section 6.

2.7.5 Enablers

The successful implementation of our Asset Management Strategy is made possible by our enablers – the people, information, tools, and technology that drive our operations. The skill and commitment of our workforce, coupled with asset management tools and data analytics, support informed decision-making, improve efficiency and enable us to deliver a higher quality of service. For more detail on this aspect, see Section 4.

2.7.6 Asset Management Plan

Our Asset Management Plan serves a critical tactical function. It sets out our detailed plans for operation, maintenance, investment, and decommissioning or replacement of assets over the next 10 years. The AMP shows our decision-making process and demonstrates how we balance the needs for maintaining existing assets with the necessity of investing in new assets, services or technologies. It provides the basis for making informed decisions about capital and operational expenditure, risk management, network development, and service delivery. Our AMP offers a clear vision of Orion's future direction and the strategies and expenditure forecasts that will help us achieve our goals.

2.7.7 Delivery

Delivery is the execution phase of our Asset Management Strategy. We implement the strategies defined in the AMP through careful project management, aligning our resources to deliver the outcomes as per our strategic objectives. We use a post project review process to identify any areas for improvement and to monitor how well we performed against the budget and timeframe requirements. We use these reviews to improve on the next projects so that we are continuously maturing in our delivery process. For our delivery strategy, see Section 9.

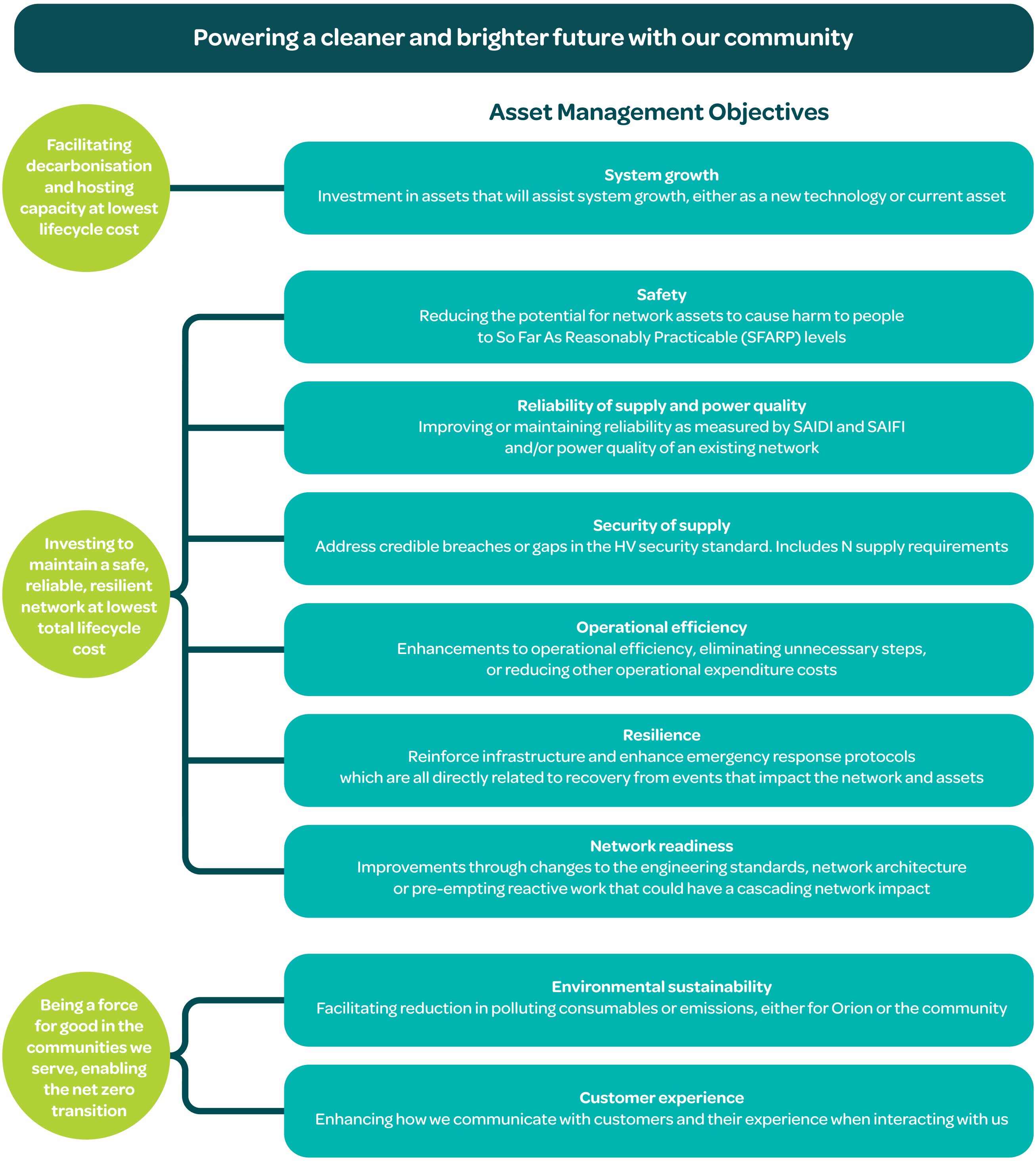
2.7.8 KPIs for continuous improvement

Our commitment to good practice asset management is reflected in our focus on continuous improvement. We monitor a range of Key Performance Indicators (KPIs) across all areas of our business. These KPIs give us a clear understanding of our performance, helping us to identify areas of success and areas where improvements can be made. These KPIs enable us to track how well we are achieving our organisational and asset management objectives. The KPIs across different levels of the business allow us to analyse data for audits, benchmarking and performance monitoring. For performance against targets, see Section 3.

2.8 Asset Management Objectives

Our asset management objectives are developed to support our Orion Group Purpose to power a cleaner and brighter future with our community. These objectives are guided by our Asset Management Policy and are instrumental in guiding our decisions about infrastructure development, network maintenance, technological advancements, and overall capital and operational expenditure. Our Asset Management Objectives align with our Focus Areas and support our ability to succeed as a business, see Figure 2.8.1.

Figure 2.8.1 Linking Orion's Focus Areas to Asset Management Objectives



2.9 Asset Management Plan development process

An overview of our AMP development and review process is provided in Figure 2.9.1. Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology to remain one of the most reliable, resilient, and efficient electricity networks in the country.

Our AMP development process is robust and includes challenge from peers, our leadership team and board. It is a collaborative effort that combines and leverages the talents, skills, and experience of our people. The development of our final work plans is the result of working together, testing and challenging our thinking and calibrating our direction against customer feedback.

Figure 2.9.1 AMP development process

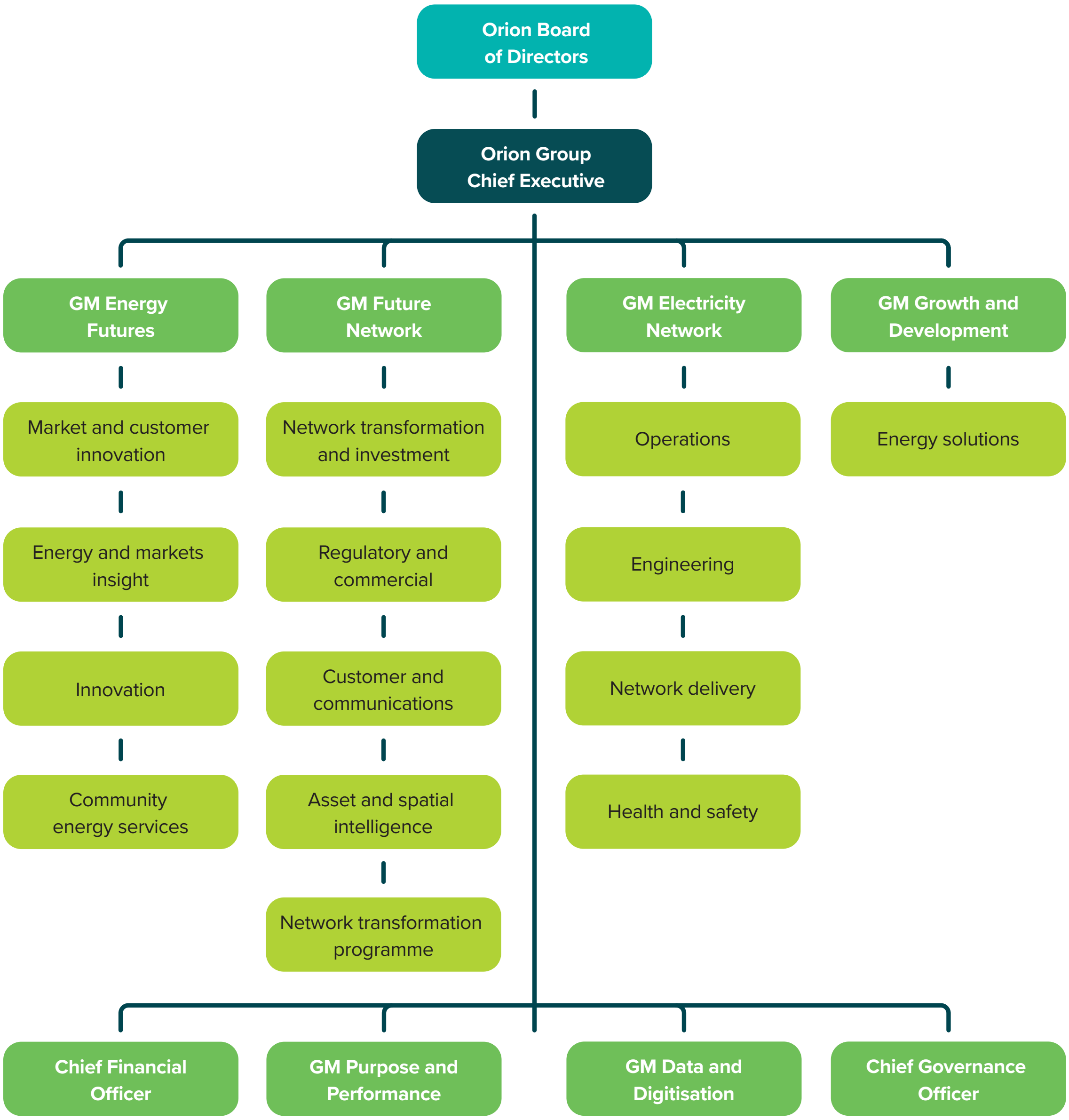
AMP development process

	Our board	Our leadership	Our customers
Group Strategy Ensure alignment of Group Strategy across SOI, Business Plan, Asset Management Policy and Asset Management Strategy	Board approves Group Strategy, SOI, and group business plan Reconfirm asset management strategic drivers with board	Leadership team strategy sessions Link strategy to asset management	Test asset management focus areas with customers Customer Advisory Panel consultation
Monitoring performance and adjusting Track performance, report and make operational adjustments to improve efficiency and adopt innovations	Reconfirm strategy, drivers and service level assumptions Progress update on AMP	Review actual vs forecast expenditure, review asset failure modes & report on reliability performance, calibrate/update CBRM Assess network and non-network alternatives. Assess load/growth Independent audits	Stakeholder consultation Incorporate customer feedback in economic analysis
AMR/Business cases Ensure data, systems, analysis tools, capability, engineering judgement and consideration of stakeholder interests result in appropriately documented efficient and prudent investment decisions	Key AMRs and business case as required Ensure appropriate resource and capability	Create/update AMRs and business case Network asset budget challenge (August)	Incorporate customer expectations and stakeholder interests
AMP Effectively communicate our expenditure plans, both short and long term, in a way that demonstrates our best practice stewardship of the electricity distribution system	Review, challenge and certify the AMP	Signal key AMP improvements, and key expenditure step changes/ additions to board Publish AMP. AMP presentation to staff	Incorporate customer expectations and stakeholder interests

2.10 Asset management roles and accountabilities

Our network is managed and operated from our administration office in Christchurch at 565 Wairakei Rd. Our governance/management structure is as follows.

Figure 2.10.1 Asset management structure



Orion Board

The Board of Directors at Orion is appointed by its shareholders to govern and direct the company's activities. The board meets eight times a year to receive updates from the leadership team on various aspects including progress against strategy, objectives, legislative compliance, risk management, and performance against targets.

Key responsibilities related to asset management include:

- Setting the direction and control of the company, which includes the group strategy pertaining to asset management.
- Overseeing the company's commercial performance, business plans, policies, and budgets which influence decisions about asset procurement, management, and disposal.
- Reviewing and approving the 10-year Asset Management Plan (AMP) prior to the start of each financial year.
- Formally reviewing and approving key company policies each year, including those related to asset management and expenditure.
- Signing of AMP certification.

2.10 Asset management roles and accountabilities continued

Orion Group Chief Executive

The Group Chief Executive is responsible for the execution of the board's strategic direction and the day-to-day management of the company. With respect to asset management, the Chief Executive's responsibilities include:

- Implementing asset management strategy as approved by the board.
- Ensuring the company has the necessary resources to manage and maintain its assets effectively.
- Reporting on performance against the strategic plan to the board, including updates on asset management.

General Managers

General Managers at Orion are part of the Integrated Leadership Team (ILT) and manage specific departments or functions. Their responsibilities related to asset management include:

- Managing their respective budgets, which include the assets under their control, while operating within their delegated authorities.
- Participating in the internal approval process for technical business cases related to asset management. This involves going through several checkpoints, including substation, or overhead working groups and a technical working group.
- Depending on the magnitude of the expenditure related to the asset, final approval might come from either the CEO or the board.

3 Customer and performance

Photo: “Powerful Conversations” workshop participants sharing their views on our prioritisation of expenditure.

Contents

3.1 Introduction

For Orion to operate a safe, reliable, resilient and affordable network that can support the region's energy transition and decarbonisation goals, we must understand the needs and wants of the people who use and rely on electricity.

In this section, we focus on our engagement with our customers. We describe the different channels we use to engage with these key stakeholders, what they are telling us and how they rate our performance.

The section also sets out the performance measures and targets we set ourselves, and those set for us by the Commerce Commission, and how we perform against them.

As the energy sector moves through a period of unprecedented change, it is more important than ever that we understand what our customers expect of us, and where they would like us to invest to support their vision for the future.

While all regions in New Zealand face the same energy transition at the macro level, each region's unique context means the challenges faced are not always the same. It is important we work with our customers and other key stakeholders to enable regional transition pathways reflecting our region's unique context, drivers and community values.

3.2 Stakeholder interests

Figure 3.2.1 Stakeholders and their interests

3.2 Stakeholder interests continued

Our stakeholders and their interests are summarised in Figure 3.2.1.

In developing the Orion Group Strategy and this AMP, we have taken the needs of a variety of stakeholders into account.

While each has their own perspective and individual needs, our stakeholder engagement programme has identified common themes that we take into consideration in our AMP planning and project assessment processes.

Our stakeholders are consistent in their view of the importance of Orion providing:

- Reliable service
- A network that is resilient
- Value for money
- A sustainable business
- Opportunities to provide their perspective
- Being pragmatic about risk management – with the safety of people paramount
- Being disaster ready; quick to respond
- Being future ready
- Being prepared for climate change risks and opportunities
- Being proactive in reducing our carbon emissions, and helping others to reduce their emissions

Orion has a key role in facilitating and supporting the energy transition. To make this shift, it is vital our stakeholders trust us, and are confident we can deliver for the future of our region.

3.3 Customer engagement

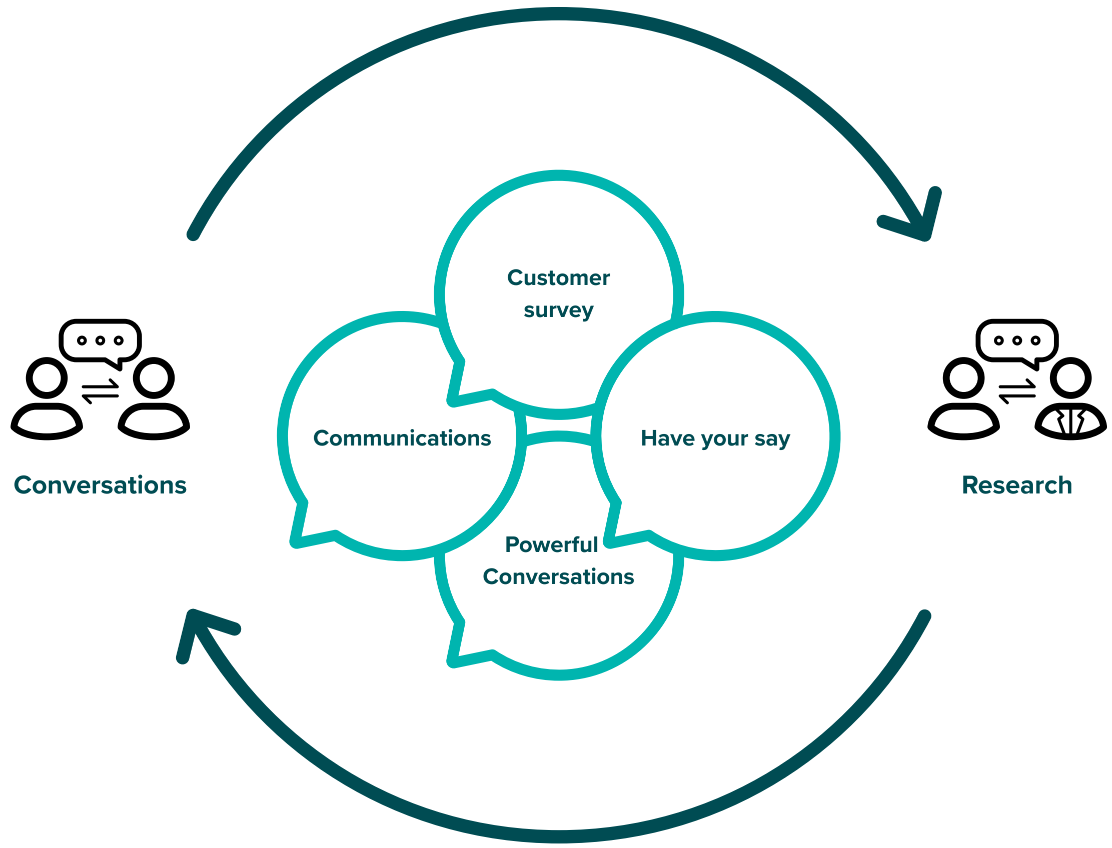
As well as physically maintaining our infrastructure, keeping our network operating sustainably and delivering on our Purpose is also about knowing our customers, what their needs and aspirations are, and ensuring we contribute positively to their lives.

We do that by actively consulting with our customers and getting to know them better.

We seek out our customers' views on a wide range of topics including future investments, our customer service and how they see emerging technologies offering new ways to manage their energy consumption at home, in the workplace and on the road.

This has never been more important than it is today.

Figure 3.3.1 Customer engagement process



The electricity sector is in an era of transformation, driven by the climate emergency, evolving technology and shifting customer expectations.

Our customers want affordable power, more control over where their energy comes from, and how they consume it. They are looking for flexibility, more choice, energy independence and opportunities to help New Zealand's efforts to address climate change through using renewable energy.

It is vital we adapt our business to respond to customer driven demands.

We have taken significant steps to listen more closely to our customers through many forms of engagement.

Figure 3.3.2 How our customer engagement helps Orion to:

3.3.1 Customer Advisory Panel

Orion's Customer Advisory Panel continues to provide a valuable forum for us to engage with leaders of community groups, business leaders and non-government organisations that represent the interests of a broad cross-section of our customers. With a customer advocacy focus, the Panel helps us understand customer needs, issues and service requirements.

Orion's Customer Advisory Panel provides valuable insights that inform our asset management strategy. This year, we plan to deepen our engagement with customers through focus groups and targeted interactions with specific customer segments. Our aim is to keep them informed about our investment levels and the reasoning behind them, while also using these engagements as an opportunity to validate our ideas and strategies with their feedback.

3.3.2 Customer satisfaction research

Our customers are important to us. To understand their satisfaction with our service, customers' views on our network reliability, their level of trust in Orion, and opinions on a variety of topical matters, Orion commissions an annual customer satisfaction survey, carried out by independent researchers.

This is a robust survey of a representative sample of urban and rural residential customers in our region. In FY23 we also surveyed business customers.

As we survey a significant number of people across our region, we can breakdown our survey results into broad locations including urban, rural and remote rural, and targeted townships or areas where we suspect local issues may prompt views that differ from the overall result. This enables us to identify areas where satisfaction is below average and increased engagement with the local community or investment in our network would be welcomed.

3.3.3 "Powerful Conversations" workshops

In FY23, we re-instigated our "Powerful Conversations" workshops with around 50 customers from both metro and rural communities. In an informal, conversational setting moderated by independent researchers, we sought customers' views on what they see as our investment priorities. These workshops enable us understand what our customers think on a deeper level, and tease out why they feel the way they do.

This year, we plan to deepen our engagement with customers through focus groups and targeted interactions with specific customer segments.

3.3.4 "Always-on" Customer Support team

Our 24/7 Customer Support Team talks with our customers daily about the service they receive. Through emails and more than 1,800 calls per month we gain a rich understanding of what's important to our customers.

These conversations enable us to respond to the immediate interests of our customers and identify any prevalent concerns or opportunities to continuously improve our service.

3.3.5 Snap Send Solve

Giving our customers a simple way to report something out of place on our network improves public safety and allows us to address the issue quickly.

In 2022 we launched Orion's presence on Snap Send Solve, an online channel for our customers and community to report non-urgent issues on our network.

Snap Send Solve is a free app, used by local authorities and utilities across Australia and New Zealand, that simplifies the reporting of asset issues for the community.

In its first year, we received more than 260 notifications of non-urgent network issues and 1,550 notifications of graffiti affecting Orion assets, which we respond to promptly.

Through the app, users can rate their experience, and we consistency receive positive feedback. This led to Orion receiving the Snap Send Solve Customer Service Award in the 2023 Solver of the Year Awards.

3.3.6 Resolving customer complaints

Our management of customer complaints provides Orion with insights on customer satisfaction with our performance and highlights opportunities to improve our service or operational efficiency.

Orion's Customer Support team operates 24/7 and all team members are trained on how to respond to customer complaints. If not immediately resolved satisfactorily with the customer, the complaint is escalated to a dedicated resolutions specialist.

Giving our customers a simple way to report something out of place on our network improves public safety and allows us to address the issue quickly.

Our management of customer complaints provides Orion with insights on customer satisfaction with our performance, and highlights opportunities to improve our service or operational efficiency.

We keep a full record of all complaint interactions in our online Incident Management system. This ensures everyone dealing with the complaint is aware of the current position, and provides a record of events should the matter become a legal or insurance issue, or is escalated to Utilities Disputes Ltd.

In accordance with clause 11.30A of the Electricity Industry Participation Code, customers are routinely advised through multiple channels of their option to escalate their complaint for independent arbitration by Utilities Disputes Ltd.

We convene our Complaints Forum as needed to consider escalated complaints and decide on the course of action to be taken.

The Complaints Forum consists of our Head of Customer and Communications, External Engagement Lead, GM Future Network, GM Electricity Network, Customer Support Manager and the Customer Support complaints specialist handling the complaint.

Orion credits its empathetic, pragmatic, and speedy resolutions process, combined with real human interaction, for its record of successfully resolving customer complaints.

3.3.7 How we manage conflicting interests

Our aim is always to seek consensus and a "win-win" approach to negotiation when conflicting interests arise. We invite dialogue with all parties and have an open approach to providing the rationale for our position and are flexible in our consideration of possible alternative solutions.

Except for matters of safety where we stand firm, we generally take an empathetic approach to understanding alternative perspectives and needs and appreciate the value of a long term, positive relationship.

While some of these issues present via our Complaints Forum, most are identified and resolved at the early engagement and design stage.

3.3.8 Outage notification

Our customers tell us that the reliability of our network is a priority. We know power outages are inconvenient, and keeping customers informed about outages, both planned and unplanned, reduces disruption.

Our website provides real-time details of power outages and updates on our progress with restoration.

Customers can also report an outage through our website and sign up for our outage notification service through the website. Customers who sign up to the service receive email and text notifications in advance of planned outages, and updates should the outage change. Where practical, our Customer Support team will also proactively call customers to inform them of changes to outage dates and times when circumstances dictate changes in our plans. For major projects, we distribute Work Notices and door-knock customers impacted to provide them with information about what we are doing and why, and keep them up to date with any changes to our plans.

Our website provides real-time details of power outages and updates on our progress with restoration.

3.3.9 Customer engagement over new connections

In response to record numbers of new customers joining our network and customer feedback, we provide customers with a user-friendly online portal to enter their requests for connection. The portal enables customers and electricians to check on where new connections requests sit and address any hold-ups as they progress through the process. Along with initiatives to streamline the process, this has reduced connections timeframes, and improved customer communications.

For more information on our practices for connecting consumers, see our Additional disclosures requirements document, regarding New connections application and associated processes, available on our website: Orion-additional-disclosure-requirements-June-2024.pdf

3.4 Community engagement

3.4.1 Community engagement over major projects

Our community expects to be informed about significant work that affects them, and we have increased our engagement for major projects.

Where major projects have a significant impact, we provide enhanced levels of communication and engagement directly with affected stakeholders, customers and the community.

Our oil filled 66kV cable replacement programme which runs along a busy arterial road in Christchurch, is an example of where we have implemented significantly increased engagement with directly affected residents and businesses along the route, commuters, and commercial traffic.

Major project engagement can include an on-the-ground presence for information and issues resolution, Work Notices with details of the projects, the benefits and the impacts on their service during the work along with a point of contact, and updates via emails and texts. We also provide presentations to local Community Boards, place advertisements with updates in local media and provide information via community channels.

Our community expects to be informed about significant work that affects them, and we have increased our engagement for major projects.

3.4.2 Social media

Orion is now reaching out to our community through social media. Through our LinkedIn and Facebook channels we are using storytelling to provide a new and deeper understanding of what we do. These two-way channels also provide us with another means to hear what's important to our customers and gather their feedback.

3.4.3 Orion "Have your say"

Making it easier for our community to engage with us is key to connecting and understanding their needs and wants.

"Have your Say" is a digital community engagement platform that allows us to understand our community's needs.

In a "Have your say" forum we keep impacted customers up to date on major projects and engage in two-way dialogue to seek our community's views.

With "Have your say" we have created a custom-built website and a range of modern digital experiences to interact on a range of topics with our unique community.

3.4.4 Sponsorship and events

Sponsorships, trade shows, public exhibitions and social media are used to promote public safety messages, news about power outages and advice on future technologies, along with an invitation to provide us with feedback. These include:

- Media releases, briefings and interviews
- Facebook posts and LinkedIn updates
- Sponsorships and partnerships that enable us to engage with our community on important power matters, and support energy innovation, such as the Orion Energy Accelerator programme
- Displays at trade shows for the farming and general community

The Orion Community Update also includes information on what to do if customers' power is out and how they can be prepared in the event of a long-term outage.

Sponsorships, trade shows, public exhibitions and social media are used to promote public safety messages, news about power outages and advice on future technologies.

3.4.5 Media and advertising

Through online, newspaper, magazine, billboard and radio channels our advertising campaigns focus on encouraging behaviours that have an impact on maintaining our network reliability and public safety. Topics include:

- The need to trim trees away from power lines – metro and rural versions
- Farm safety around power lines
- DIY safety
- Encouraging people to come see us to discuss safety around power lines at local A&P shows
- If it doesn't look right, our "Dial it in" campaign is responding to the ongoing issue of people tampering with our network

3.4.6 Orion Community Updates

In December 2023, Orion launched a new publication to address community feedback that more information would be welcome on major network developments, our preparedness for future natural disasters, greater awareness of our operations and services, and steps we are taking to prepare for a changed energy future.

The Community Update also includes information on what to do if customers' power is out and how they can be prepared in the event of a long-term outage.

Distributed with community newspapers to approximately 110,000 addresses throughout Christchurch and the Selwyn district and online, the Orion Community Update has been well received and will be issued two times per year.

3.5 What our customers have told us

Our customers have provided a useful picture of what is important to them, and where they would like us to concentrate our attention and investment. Consistently throughout our conversations and research, customers are aligned with and have endorsed the strategic focus and guiding principles of our asset management strategy.

This section sets out the latest views of our customers gathered from our various customer engagement activities.

Figure 3.5.1 Key results from our Annual Customer Satisfaction Survey, 2023

Orion's overall performance

8.3 AVG.

Satisfied with Orion as a lines company

30%

10/10 satisfaction with Orion

Brand reputation

80%

agree Orion is **capable** and **effective**

78%

agree Orion **carries out its duties very well**

61%

agree Orion **acts in the interests of local residents**

49%

agree Orion **is well prepared for future natural disaster situations**

40%

agree Orion **is prepared for a very different future for electricity**

Awareness and perceptions of Orion

58%

Awareness of Orion

50% correctly identified Orion

89%

Satisfied with reliability

78%

Trustworthy

57%

Aware of the **Orion website**

46%

Aware of the **Orion Customer Support team**

Customer experience

8.8 AVG.

Rating of **service received**

8.9 AVG.

Rating of **ease of doing business with Orion**

3.5.1 Customer satisfaction research results

We gather a wealth of information on what our customers think of our service. Figure 3.5.1 shows the key results from our latest annual customer satisfaction survey. While there were some differences between our residential and business customer's ratings, these were small. The combined average overall ratings are provided here.

3.5.2 Capability and competence

Our customer research shows people are very confident in Orion's current capability and competence in management of the power network. As shown in Figure 3.5.1, among a range of strongly positive scores in our latest Customer Satisfaction survey, 80% agree that Orion is capable and effective in the management of our network, and 78% say we carry out our duties very well.

3.5.3 Safe, reliable, resilient network

The key views of our customers on the safety, reliability and resilience of our network are:

- That our network is safe is "a given" for our customers. We recognise and respect the high level of public trust in the safe operation of our network.
- In all our conversations with customers, the importance of being provided with a resilient and reliable service is an abiding theme. Customers tell us that focusing on providing a resilient and reliable service should be fundamental for Orion. They want us to continue to invest in increasing the resilience of our network. Most customers are highly satisfied with Orion's current levels of reliability, and do not support investment to increase reliability if that comes with increased prices. Our October 2023 annual customer satisfaction survey found 89% were satisfied with the reliability of their power supply. See Figure 3.5.1.
- Resilience is very important to our customers, and this has been reinforced by the 2023 flood events in Auckland and the East Coast of the North Island. Our customers tell us Orion's investment in resilience represents good value for them. Customers have low tolerance for long outages and want Orion to invest in resilience with this in mind.

3.5.4 Energy equity: access and affordability

From conversations with our customers, we understand that many are struggling to pay their power bills. We are having ongoing discussions with our customers to better understand the issues of energy equity and developing ways to help those in need. We will also explore customers' views on the impacts on customers' bills of gearing our network up for the future.

3.5.5 Health and safety

Customers have asked us to take a "common sense" approach to managing safety risks. They say protecting human life and avoiding injury is paramount. They believe Orion should balance the costs and risks associated with safety issues when addressing them.

The success of our public and business safety education campaigns is positively reflected in the number of occasions Orion is asked for a close approach consent from both residential and commercial customers. At consistently around 4,500 requests per year this is among the highest rates for EDBs in New Zealand. We have a semi-automated application process for close approach, high load and standover consents that has vastly improved our operational efficiency and supported safety outcomes.

3.5.6 Future focus

In our annual satisfaction survey, we found customers are less confident in our readiness for future natural disasters and preparedness for the future. Only 40% agree that Orion is prepared for a very different future for electricity where customers have more choice about where they get their power from, how they use it and share it with others. Uncertainty, unawareness and lack of communication drive this perception.

This is not an issue that is peculiar to Orion. The general public, regulatory and political stakeholders have noted the sector needs to simplify and be more proactive and cohesive with its communications about the future of energy in New Zealand. In recent industry research more than half of those surveyed said it was important that sector companies do more to communicate the steps they are taking to address climate change.

We have our Energy Futures team leading and collaborating to develop new and innovative energy solutions, and a Network Transformation team to define and design the network to meet our customers' future needs. For Orion, and the wider energy sector, communicating our plans and vision for the future to stakeholders is a priority.

For Orion, and the wider energy sector, communicating our plans and vision for the future to stakeholders is a priority.

3.5.7 Investment priorities

To achieve our Purpose, our customers must see their voice reflected in our asset investment decisions and asset management practices.

In our latest "Powerful Conversations" workshops we asked around 50 customers to rank investment priorities. Through two workshops, one with urban and one with rural customers, participants ranked resilience, operational efficiency, future readiness, sustainability, and customer experience in order of importance. See Figure 3.5.2.

For both urban and rural customers the clear priority, now and for the future, was investment in the resilience of the network. The importance of reliability was also seen as part of resilience. Our customers wanted to see as few disruptions to supply as possible, and power restored as quickly as possible.

Sustainability and future readiness were also important, although rural customers were more focused on operational efficiency in the shorter-term.

Customer experience and operational efficiency ranked low relative to other priorities. This was due to the perception that if all other priorities were taken care of, these would be too. In comments however, participants valued investment in customer experience when thinking about others' needs, particularly vulnerable customers, and during outages.

Figure 3.5.2 Customer investment priorities

Urban customers' investment priorities

Now	Future
Resilience	Resilience
Sustainability	Sustainability
Future readiness	Future readiness
Customer experience	Customer experience
Operational efficiency	Operational efficiency

Rural customers' investment priorities

Now	Future
Resilience	Resilience
Operational efficiency	Future readiness
Future readiness	Sustainability
Sustainability	Operational efficiency
Customer experience	Customer experience

3.5.8 Communications

Our customers have told us how they would like us to communicate with them about planned outages, and when. In general, residential customers would like personal direct communication about upcoming outages, a week or so before the event. They like to know what the outage is for, and how they will benefit. They also want us to respond to any concerns they raise about community impacts.

They prefer one big, all day outage over multiple shorter outages over an extended period.

Business customers tell us they need more notice to plan for interruptions to their operations.

3.5.9 Customer experience

In FY24 we introduced a new methodology for seeking our customer's rating of our customer service. In the past we used a tailored version of a net promoter score and focused on our Customer Support team interactions only. This year we extended the focus to a broader span of experience.

Our customers were highly satisfied with their interactions with us, with an average score of 8.8 out of 10 for the service received, and 8.9 out of 10 for the ease of doing business with us.

In the FY24 annual survey we saw a significant increase in awareness of two channels that contribute to satisfaction with the customer experience. Awareness of the Orion website increased from 47% to 57%; and awareness of our customer support service increased from 35% to 46%.

3.6 Turning listening into action

We have instigated a range of initiatives that translate what we have learned in our conversations with customers and other stakeholders into action.

We will continue to seek our customer and other stakeholders' views on our core network services and future direction.

Figure 3.6.1 Customers' views and our actions to address them

What we heard	What we are doing
Customer experience • Tell us about works that will affect us • Give us more information when the power goes out • Make our day-to-day transactions easy and quick	• Published the Orion Community Update • Implemented an opt-in outage notification service • Proactive communications before significant planned outages, including Transpower GEN notices • Implemented a semi-automated, online application process for new connections • Implemented Snap Send Solve to give customers a simple way to report something out of place
Safe, reliable and resilient network • Have as few disruptions to supply as possible • If supply disruptions happen, restore supply as quickly as possible	• Constructed a new Grid Exit Point at Norwood • Replacing older oil filled cables • Extensive pole assessment and replacement programme • Enabled an Automatic Power Restoration System to restore customers quicker after a fault • Exploring flexibility solutions for Lincoln to manage peak demand • Carried out a Coordinated Incident Management System training exercise
Health and safety • Keep us safe, but not at any cost	• Implemented a semi-automated, online application process for consents • Increased the frequency and reach of our public safety education campaigns
Sustainability • Take action to address the climate emergency	• Achieved carbon neutrality for corporate emissions • Partnered with Wairewa Rūnanga to replant Te Kaio farm in natives to offset emissions and restore the whenua • Lead partner in Ara Ake Decarbonisation Challenge
Affordability • Help address energy hardship	• Supported Community Energy Action • Supported Ecobulb in energy assessments for 200 Christchurch households
Future network • Reassure us you're ready to support our future needs • Tell us what the energy future holds	• Published the Orion Community Update • Initiated "Energy Exchange" event series to connect parties involved in Canterbury's energy transition • Developed Future Energy Scenarios to model the impacts of the energy transition on our network • Collaborating with other sector organisations on the "Powering Change" programme of collective action

3.7 Performance against targets

Table 3.7.1 provides a summary of how we have performed against our targets for the key measures related to management of our assets, the environment and customer experience.

Table 3.7.1 Summary of performance against targets

Focus area in Orion Group Strategy	Asset management objective	KPI description	FY23 target	FY23 performance	Achieved	FY24 and FY25 targets
Facilitating decarbonisation and hosting capacity at lowest cost	System growth	% of transformers monitored across Orion's LV network	9%	6%	✗	9% for FY24
		Network-led flexibility: capacity available through hot water load control	100MW	190MW	✓	100MW
Investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost	Safety**	Safety of Orion Group employees	≤ 4 serious events	4	✓	≤ 4 serious events
		Safety of service providers	≤ 4 serious events	2	✓	≤ 4 serious events
		Safety of the public	≤ 1 serious events	1	✓	≤ 1 serious events
	Reliability of supply and power quality	SAIDI Planned	FY21-25 limit < 198.81	73.79	✓	FY21-25 limit < 198.81
		SAIDI Unplanned	Limit < 84.7	43.38	✓	Limit < 84.7
		SAIFI Planned SAIFI Unplanned	Limit < 1.03 No limit	0.07 0.51	✓	Limit < 1.03 No limit
		Power quality: number of escalated customer complaints	< 60	14	✓	< 60
		Power quality: number of proven harmonics or distortion complaints	< 4	2	✓	< 4
		Unplanned interruptions restored within 3 hours	> 60%	66%	✓	> 60%
	Security of Supply	No. of breaches in the Security of Supply Standard – Transpower GXP	≤ 2	2	✓	≤ 2
		No. of breaches in the Security of Supply Standard – Subtransmission	≤ 6	7	✗	≤ 6
	Operational efficiency	Operational expenditure per MWh	< 24.4	21.2	✓	< NZ comparator group average
	Resilience	To be set	To be set	n/a	n/a	RMMAT score, see Section 5.10.5
	Network readiness	To be set	To be set	n/a	n/a	n/a
Being a force for good in the communities we serve, enabling the net zero transition	Environmental sustainability	SF_6 gas lost	< 0.8%	0.6	✓	< 0.8%
		Grams CO2e per MWh delivered – excludes distribution losses	< 200g grams CO2e per MWh delivered	120	✓	< 200g grams CO2e per MWh delivered
	Customer experience *	Customer experience: service received	> 8 out of 10	8.8	✓	8.8 out of 10
		Customer experience: ease of doing business with us	> 8 out of 10	8.9	✓	8.9 out of 10

* New KPIs set and measured in FY24

** For the purposes of the AMP, people-safety metrics have been reported under the Orion Focus area: Investing to maintain a safe, reliable, resilient network at lowest total lifecycle cost. In other external documents, people-safety metrics are cited under Creating the preferred workplace.

3.7.1 System growth

How we will achieve our objectives

Invest proactively to manage a future constraint on the network. Prevent possible future breaches or gaps in security standards. Either by investing in our current assets, new technology or approaches, providing enhanced future options, including flexibility options.

Our network is facing significant change from increasing electricity demand due to decarbonisation and new ways of managing energy. This presents both challenges and opportunities to Orion in how we manage our network.

Where in the past projections of historical trends could form a reliable picture of the future, we now need to forecast emerging and uncertain trends and markets.

One impact of the energy sector's transition is that Orion's historical approach to forecasting is no longer appropriate. Where in the past projections of historical trends could form a reliable picture of the future, we now need to forecast emerging and uncertain trends and markets. This leads us to a greater use of scenario modelling. For more on growth and our approach to modeling future scenarios, see Section 2.

The improvements we are making are driven by both the greater uncertainty we have around customers' behaviour and how new technology will be used by them, and the greater network visibility we are developing, particularly at low voltage level.

400V LV network visibility

Our 400V Low Voltage (LV) network will increasingly need to support new and more complex two-way power flows as customers progressively adopt alternative ways to power their homes, businesses and vehicles. We are installing new equipment in Christchurch residential areas that enables us to monitor the use of power in near real time, at street level.

We are installing new equipment in Christchurch residential areas that enables us to monitor the use of power in near real time, at street level.

These low voltage monitors sample power flows and voltage at 10 minute intervals, generating a wealth of data that will allow us to see and respond to changes of activity on the network. Having visibility of how our network is being used at this granular level will also help us provide customers with a more flexible, dynamic range of choices for managing their energy needs. See Section 8.4.4.1 for more information on our 400v LV monitoring project.

Performance against targets

In FY23 we installed 312 monitors, bringing the percent of our transformers monitored to 6% of the total number, below our 9% target.

Apart from installing low voltage monitoring equipment to enhance network monitoring, we have also acquired smart meter network data that covers 95% of our network. The analysis of this data will give us insights into the performance of our 400V LV network.

We comfortably exceeded our target for network-led flexibility through hot water load control.

3.7.2 Safety

How we will achieve our objective

Reduce the potential for network assets to cause harm to people to So Far as Reasonably Practicable (SFAIRP) levels.

We are committed to providing a safe, reliable network and a healthy work environment around our assets. We take all practical steps to minimise the risk of harm to the public, our service providers and our people.

We report all employee injury and public safety events that are asset related via the Vault safety information management system and collect similar statistical incident data from our service providers. These service provider statistics, our own statistical data and our incident investigation enable us to provide our people and service providers with indicators of potential harm when working on or near our assets.

Performance against targets

While achieving our targets in all three categories, we had a total of five safety events in FY23, three involving Orion Group employees, one involving an employee of our service providers, and one involving a member of the public. None of these events resulted in serious injury.

WorkSafe was notified of these events, which were:

- A Connetics employee received an electric shock from contact with a low voltage cable
- A Connetics employee received an electric shock while testing circuit breakers at a zone substation
- An Orion network operator received a minor electric shock while replacing a distribution box cover
- An employee of one of our service providers received an electric shock while relocating a distribution cabinet
- A civil contractor, not engaged by Orion, came into contact with our low voltage network

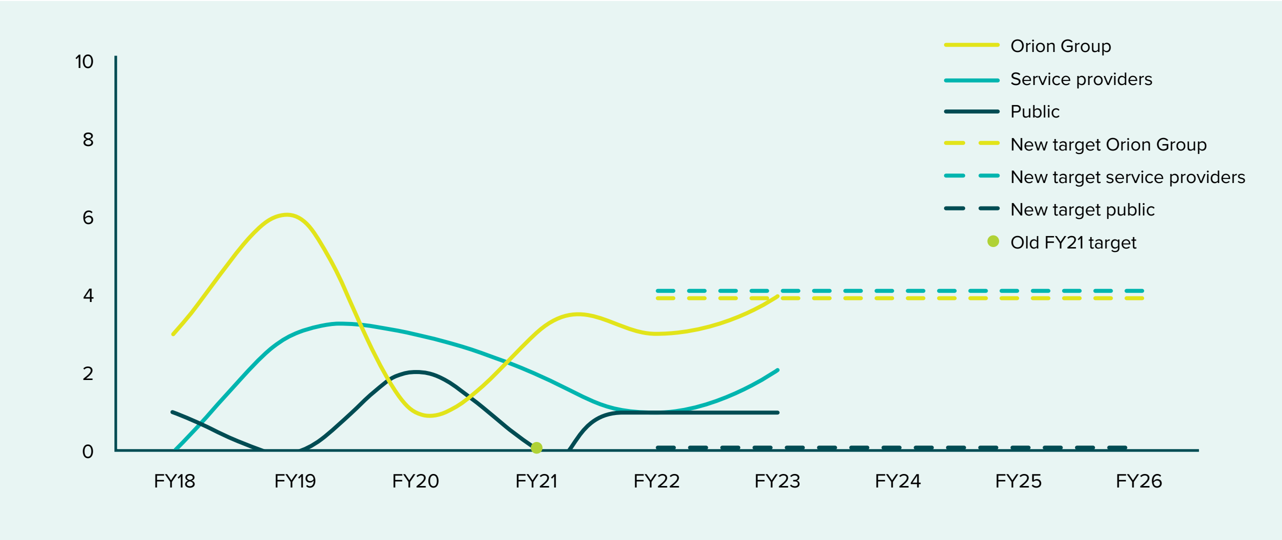
We will continue to focus on improving the effectiveness of the control of critical harm. Our asset maintenance and replacement programmes are fundamental to ensuring our safety targets are met in the future.

SAIDI and SAIFI apply to the planned and unplanned interruptions of a duration longer than one minute on our subtransmission and high voltage distribution system.

The SAIDI and SAIFI limits set by the Commerce Commission are thresholds that going beyond will result in a quality breach, which may lead to fines of up to $5 million. The unplanned interruption limits apply annually, which means that any year where the unplanned limit is exceeded will result in a breach.

Planned interruption limits are assessed on a five year basis at the end of the regulatory period.

Figure 3.7.1 Safety performance – serious event trend and new targets



3.7.3 Reliability of supply and power quality

How we will achieve our objective

- Achieve a credible reduction in the historic number of faults for a group of customers.
- Address a current SAIFI concern in the network and/or maintain power quality standards.

We measure our network performance and power quality through a variety of measures that directly relate to the customer experience.

3.7.3.1 Network reliability – SAIDI and SAIFI

Our quality of supply KPIs are as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These are:

- **SAIDI** – System Average Interruption Duration Index – the average number of minutes per annum that a customer is without electricity
- **SAIFI** – System Average Interruption Frequency Index – the average number of times per annum that a customer is without electricity

Performance against target

As shown in Figure 3.5.1, in our November 2023 annual customer survey, 89% were satisfied with the reliability of their power supply.

For FY23, we achieved our network reliability performance targets and were under our limits for unplanned SAIDI and SAIFI.

Our targets and limits for SAIDI and SAIFI for FY21-FY25 include separate targets and limits for planned and unplanned events, and an extreme event measure that relates to identification and reporting of rare events.

Our historical performance and future targets are shown in Figures 3.7.2 and Figure 3.7.3.

For FY23, we achieved our network reliability performance targets and were under our limits for unplanned SAIDI and SAIFI.

Figure 3.7.2 SAIDI performance

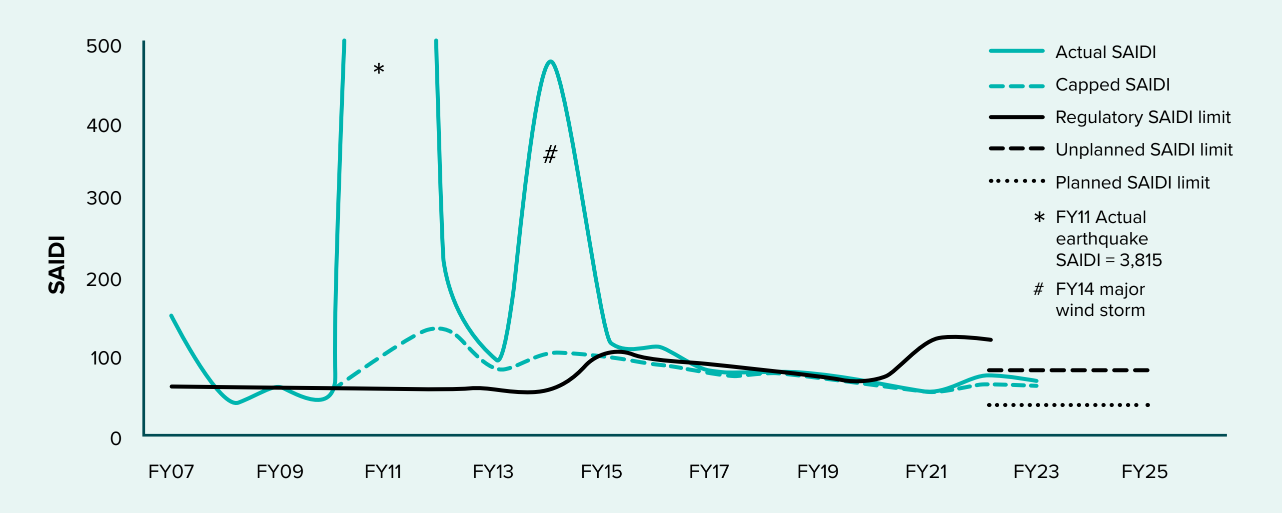
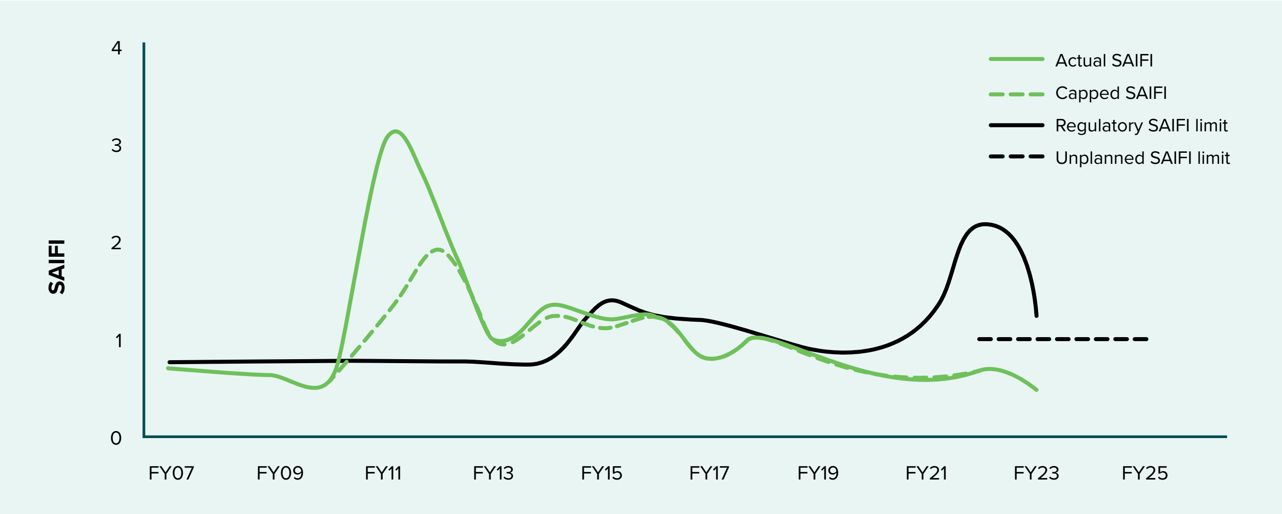


Figure 3.7.3 SAIFI performance



3.7.3.2 Unplanned interruption restoration

We have engaged an emergency service provider to manage our distribution asset spares and provide adequate response to any event on our network.

Larger scale network events have a significant impact on restoration times, as weather conditions and the number of faults occurring simultaneously affect our response time. High-impact weather events such as snow storms and high winds can create numerous faults across the network which can take an extended time to repair. As shown in Figure 3.7.3, between FY10-FY14, we had a number of such events with earthquakes, snow storms and very high wind events which impacted restoration times.

Performance against target

With improvements in fault indication, the use of drones for line surveys and the installation of a greater number of remotely controlled devices across the network, we expect the trend to show continued improvement over time as we can more quickly locate faults and restore supply. Our target and performance shows we achieved 66% restoration within three hours in FY23, above our target of > 60% restoration within three hours.

3.7.3.3 Power quality

Ensuring the quality of the power delivered by our network plays an important role in delivering a safe, reliable and resilient power supply to our customers.

Monitoring voltage quality

To ensure we meet the requirements of the Electricity (Safety) Regulations 2010, Orion has 33 permanently connected Dranetz power quality analysers, which constantly monitor and track power quality performance across our network. This includes at the extremities of our network, where supply issues are most likely to be experienced.

Our analysers monitor a full range of network voltages between 230V and 66kV. A range of parameters are measured which define the quality of voltage, current, harmonics and event capture.

This monitoring has enabled us to build a database of the power quality performance across our network that provides a benchmark for performance across a range of conditions and scenarios. It also enables us to readily identify changes and issues arising, which prompts more analysis and if necessary, corrective action.

We measure the two key performance attributes of power quality that we can influence:

- **Voltage supplied to customers** – our network is designed and operated to meet the standard New Zealand low voltage, at 230Volts +- 6%, as per Regulation 28 of the New Zealand Electrical Safety regulations 2010.
- **Harmonic levels or waveform distortion present in the power supplied to customers** – we use harmonic allocation methods defined in joint International Electrotechnical Commission (IEC)/Australian/New Zealand standards to determine acceptable customer levels of harmonic injection. These allow each customer to inject a certain acceptable amount of harmonic distortion depending on the capacity of the power supply at their premises.

Monitors deployed

A mixture of devices are used to measure a range of different power quality parameters which include voltage indices. We have a dedicated power quality monitoring program. Two types of monitors are used:

- **Permanent power quality monitors** – installed to monitor a range of different voltage levels. Generally, these have been installed at the end of our most vulnerable feeders to ensure that the up-stream network is preforming as designed.
- **Portable class A units** – used for power quality investigations which are generally customer driven.

Response to power quality complaints

Orion operates a 24/7 Customer Support team that fields all customer calls, and the team escalates power quality issues to a specialist team who engage directly with the customer to make an initial assessment of possible cause or initiate further investigation.

If needed, we actively investigate by first sending an Orion operator to the customer's premises to conduct preliminary assessment of the situation. Often the cause is identified at that point and rectified. If further investigation is required, we install power monitors, which provide an accurate record of performance over time. If our network is found to be at fault, rectification may include upgrading equipment or a conductor, or reconfiguring of our network in the interim while we develop a long-term engineering solution.

Of the issues raised around 20% are Orion network related and often matters at the customer's premises are found to be the cause of the issue. We work closely with customers or their representative to gain an accurate understanding of the issue, and can provide advice on avenues for further investigation by their service provider, or suggestions for how the issue might be rectified.

Performance against targets

We achieved our power quality targets for FY23.

3.7.4 Security of supply

How we will achieve our objective

Address credible current breaches or gaps in the published deterministic security standards. Includes supply requirements and power quality.

Our primary focus is to proactively address credible breaches or gaps in the existing deterministic security standards, with emphasis on ensuring the reliability of supply and enhancing power quality across our network. Orion's Security of Supply Standard provides a guideline for our desired state or the network to ensure it performs as required.

3.7 Performance against targets continued

The security of supply may be reduced due to network growth, major customer connections, legacy network architecture, or network faults. Having a set of guidelines that we follow ensures we are measuring ourselves against a benchmark that prompts us to continuously improvet our network. For more on security of supply see Section 6.4.2.2 HV Security of Supply Standard. Current network security gaps are listed in Section 8.3. Although our current Security of Supply Standard is deterministic, we assess the economics of the solution to ensure that we are factoring in the likelihood of the fault event occuring and the impact. Our aim is to reduce these gaps in line with our Orion Group Purpose and investment strategies.

Performance against targets

Our goal is to reduce network security gaps. The performance is difficult to measure and as we continue to review the network it is possible we will find more gaps. The Security of Supply Standard acts as a guide and there are times when mitigating the gap is cost prohibitive for the benefit gained. These gaps are typically on the subtransmission network requiring complex, costly, projects. For our current planned projects for these gaps see Section 8.4. We aim to reduce these gaps where it makes sense to invest and will continue to refine future work programme based on our scenario work to ensure we meet the needs of the future.

3.7.5 Operational efficiency

How we will achieve our objective

Facilitate a reduction in OPEX or people hours required.

Operational efficiency, as an asset management objective, underscores our aim to maximise the value we deliver while minimising the operational expenditure (OPEX) we incur.

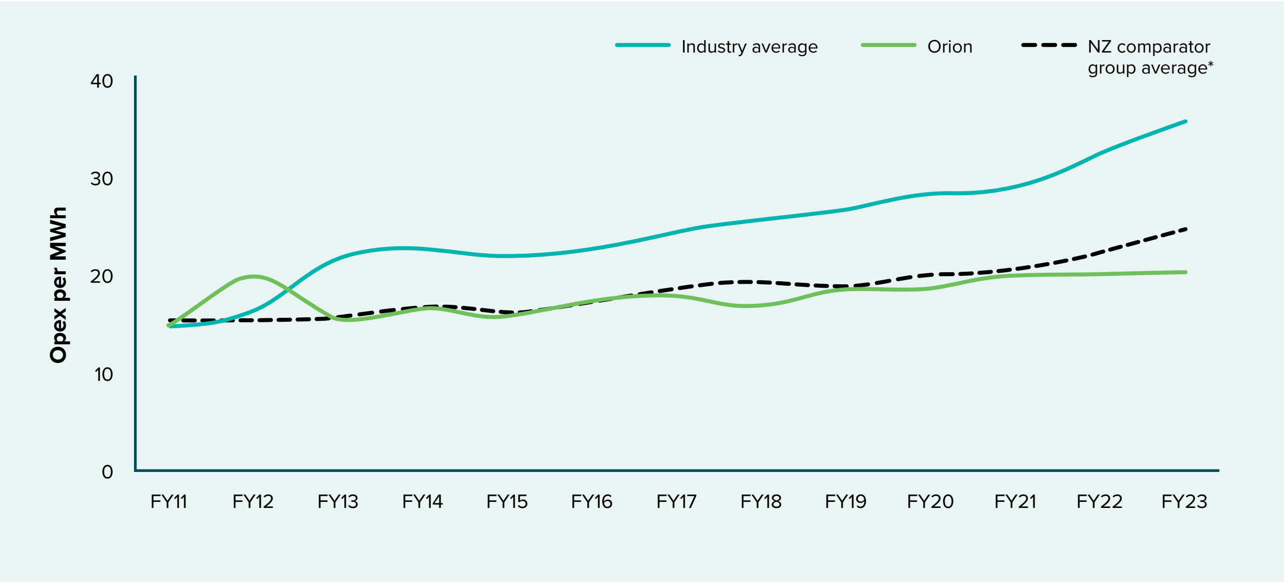
To measure our progress towards achieving improved operational efficiency, we have chosen the metric OPEX per Megawatt-hour (OPEX/MWh). This metric offers a clear and quantifiable reflection of our operational cost relative to the amount of energy we distribute. It also enables us to compare our performance to that of other EDBs. A decreasing trend in OPEX/MWh indicates that we are delivering more energy to our customers at a reduced operational cost, exemplifying our efficiency gains.

By focusing on operational efficiency, we ensure Orion remains competitive, adaptable, and ready to meet future challenges. It allows us to free up resources, both in terms of finances and people power, that can be reallocated to other critical areas such as infrastructure development, technological innovations, and customer service enhancements.

Performance against target

We achieved our target for FY23 to be more efficient than our comparator group.

Figure 3.7.4 Comparing OPEX per MWh and industry performance



* Wellington Electricity, WEL Network and Unison

3.7.6 Resilience

How we will achieve our objective

Facilitate reduction in the restore time for a group of customers after a HILP event.

We take a comprehensive approach to resilience planning for a range of events from severe storms to HILP events. Our investments in resilience are focused on reinforcing infrastructure, implementing redundancy measures, and enhancing emergency response protocols which are all directly related to recovery from events that impact the network, assets, or service provision.

A more resilient network will limit the initial impact enabling faster than otherwise restoration of power for those customers experiencing outages, and be adaptable enough to reduce the time to recovery from a major event.

Performance against target

For the first time in FY24 we completed a maturity assessment of our resilience based on the Electricity Engineers Association (EEA) Industry Resilience Guideline achieved an average score of three. This is a new metric for Orion and we are in the process of setting ourselves a performance target that reflects our broader business goals.

We are prioritising proactive investment in our network to help mitigate the future impacts of climate change.

3.7.7 Network readiness

How we will achieve our objectives

Invest proactively to stop a future increase of incidents on the network. Either through changes to the engineering standards, network architecture, or pre-empting reactive work that could have a cascading network impact, including end-of-life assets and climate adaptation.

Network readiness is about ensuring our infrastructure is prepared to withstand different types of future events. While there are many different scenarios and external influences that can impact the network, we aim to build and maintain our network so that it is flexible and adaptable to withstand multiple future scenarios. Where practical, we optimise existing work plans to include pre-emptive work if it has been identified. We also prepare the network through our end-of-life replacement programmes and are exploring the impact of future climate scenarios, to inform the level of investment required to maintain a safe, reliable and resilient network in the future.

End-of-life replacement

End-of-life replacement is part of an early investment startegy to help mitigate the impact of cascading impacts to the network. An example of this is the investment we are making in our pole replacements. Often, it is optimal to replace poles of a similar age or condition near one that has been selected for immediate end-of-life replacement. This type of planning means we can optimise our work programme and may mean an earlier-than-expected investment in replacing a pole, but can avoid the need to come back to the same area in 2-3 years' time. This type of planning helps us to reduce risk in parts of our network where there are assets of similar age or condition.

Climate adaptation

We are prioritising proactive investment in our network to help mitigate the future impacts of climate change. We base our decisions on the latest climate data and apply localised climate analysis to the network where applicable.

In FY23 and FY24, we analysed different assets using the climate risk model "Risk Explorer" which includes risks such as coastal erosion, coastal flooding, rising groundwater, and river flooding. Risk Explorer also now includes wind modelling, and we are testing scenarios to identify the most effective areas to make investments in the network.

This type of analysis and investment in risk modelling allows us to make decisions that prepare our network to continue to perform as needed for our community in the future. Measures of performance for this area will be developed as the analysis continues.

Performance against target

We don't yet have a performance metric to measure this objective, but decreasing failure rates of key asset classes can be indicative of good performance. We hope to refine this objective more with the introduction of newer integrated asset management systems.

3.7.8 Environmental sustainability

How we will achieve our objective

Facilitate a reduction in a polluting consumable or emission, for Orion for the community.

We are a passionate advocate for low carbon energy and are committed to reducing our carbon emissions, and helping others to do the same. This is pivotal to Orion delivering on our Purpose to power a cleaner and brighter future with our community.

Management of SF_6

Orion uses sulphur hexafluoride (SF_6) in our network as an electrical insulator and arc suppressant in some circuit breakers rated 11kV and above. SF_6 is an extremely potent greenhouse gas. 1kg of SF_6 is equivalent to 22,800kg of CO^2. We treat it as a climate risk and design and operate our network to avoid the potential for it to be emitted.

We have a programme to reduce our SF_6 losses by introducing a replacement schedule for the gaskets on all our 66kV circuit breakers and we are looking to phase out circuit breakers using SF_6 at 11kV.

Orion is also working to reduce the introduction of new SF_6 into the network, and we are trialling a vacuum insulated 66kV circuit breaker as part of our investigations.

Performance against targets

We are committed to minimising Orion's SF_6 emissions and carefully monitor and report losses. We have a self-imposed target of less than 0.8% annual loss to the atmosphere of the insulating gas SF_6. Orion reports to the Ministry for the Environment on our SF_6 loses, and we meet the requirements of reporting by measuring our losses to down to the nearest 50 grams of SF_6.

We achieved our FY23 target for SF_6 loss. We did not achieve our target for grams CO2e per MWh delivered as this had been based on a COVID-19 year as a benchmark, and our target has been reset to reflect resumption of our usual operations.

We are committed to reducing our operational footprint and to enable others to reduce their carbon emissions. We are developing the ability to track embodied emissions per MWh delivered, and carbon reductions we have enabled around our region.

For more information about Orion's carbon emission targets and performance, refer to our Climate Statement, available on our website.

3.7.9 Customer experience

How we will achieve our objective

- Enhancements to how we communicate with customers.
- Increasing satisfaction with their experience when interacting with us.

Using an independent research partner, we seek to understand our customers' experience and satisfaction with our performance. To better measure our customer experience, we adjusted our metric in FY24 to focus on the quality of the service received, and the ease of doing business with us. Broadening the scope of the customer experience measure means the metric encapsulates not only engagement with our Customer Support team, but also interactions with other parts of the business. This gives a more well-rounded view of our customers' experience with Orion.

Performance against targets

In FY24 we used a revised customer experience metric, and this has provided a strong benchmark for our future performance. Our scores for FY24 are excellent, and our goal for the next year will be to maintain these scores.

In our FY24 survey, we asked customers to rate the service they received and the ease of doing business with Orion. This feedback was from customers who had interacted with Orion over the last 12 months. Key findings:

- Respondents gave us an average score of 8.8 out of ten in terms of service received.
- Respondents gave us an average score of 8.9 out of ten in terms of the ease of doing business with us.

These results show our customers have an excellent experience with Orion and leave that experience feeling positive.

We asked our customers how satisfied they were with Orion as a lines company. Our customers gave us an average score of 8.3 out of ten in terms of their satisfaction with our performance, with 30% giving us a rating of 10/10. These results show a high degree of satisfaction with our performance.

4

People and technology

Photo: Andy Parr, Primary Systems and Testing Lead, contributing to a discussion with his Orion colleagues.

Contents

4.1 Introduction

In this section we describe two aspects of our business that are critical to Orion achieving the objectives of this AMP: our people and our technology.

We set out how we are planning to meet the workforce needs of the future, and outline the teams within Orion and their key functions.

Our information systems technology supports every aspect of our business and here we outline what those systems do, and how we are enhancing them to provide improved insights for our decision-making and increase operational efficiency.

4.2 Planning for changing workforce needs

Delivering our Asset Management Plan depends on having a capable and engaged workforce in place. Orion faces several challenges to attract, develop and retain the skilled people we need to ensure our network serves our community's current and future needs.

We are currently operating in a highly competitive labour market with historically low unemployment and high rates of domestic labour utilisation. We are also impacted by global workforce trends from the "Great Resignation" to the "Big Stay" as the world adjusts to the post pandemic changes in how people approach work and changes in employee expectations. In Aotearoa New Zealand we are also impacted by the restart of the rite of passage for young people departing for the Overseas Experience (OE) and the "brain drain" to Australia, lured by higher salaries. These issues are not Orion's alone, they are sector wide.

As Orion prepares for its future business needs we are mindful of the future of work, what the future workplace might look like, and the needs of the future workforce. Important considerations include:

- Increased use of AI and the decreasing half-life of technical capabilities.
- Mitigating the digital divide and the growing use of technology has on the wealth gap.
- Five generations will be present in the workforce at once.
- The drive for workplace flexibility, hybrid workplace, or remote work.

Workforce planning is a key activity to ensure we have the workforce capacity and capability required to deliver on the Orion Group Strategy and our AMP objectives.

The guiding principles for our workforce planning are:

- **Focusing on understanding the future's capability needs is crucial.** We will develop our talent profile to align with the requirements of tomorrow's workforce, ensuring we are well-prepared to meet the evolving needs of the future.
- **Recognising our future workforce needs to be more diverse** is essential to meet the evolving capability requirements and better understand the communities we serve.
- **Focusing on driving sustainable performance over time** involves ensuring our people possess the confidence and capability to actively seek opportunities for performance improvement.

Workforce planning is a key activity to ensure we have the workforce capacity and capability required to deliver on the Orion Group Strategy and our AMP objectives.

In our workforce plan we focus on developing and embedding key processes and systems, and creating an environment for our current and future workforce to thrive by 2028. Our workforce plan includes:

- Future skills identification workshops based on scenario-based exploration.
- Clear development pathways and rapid skills development opportunities identified for our people to support closing future skills gaps.
- Orion continues to strengthen our Talent Programs by ensuring depth in our succession plans and enabling talent mobility via development and growth of our people.
- We will be further supporting our legacy workforce through retirement planning.
- Targeting science, technology, engineering and mathematics (STEM) career promotion and clear industry entry pathways to attract people who reflect the community we serve and those with skillsets required to enable future growth.
- Creating an environment that supports employee wellbeing and lifts performance through Diversity, Equity, Inclusion and Belonging (DEIB) and wellbeing programmes
- Developing and implementing Technical and People Leadership, Operational Excellence and Change Management programmes to support delivery of the above.

This programme of work is a pivotal enabler for driving the future development of our network, and key to addressing one of Orion's Top 10 risks, to achieving our organisational development goals, see Risk Section 5.8.9. It enables us to anticipate and adapt to evolving asset management needs, align our human capabilities with advancements in technology and the shifting landscapes as our sector evolves to meet the changing needs of our community.

We made significant progress in developing our people and capability programme in FY23. This work, coupled with our technology roadmap and sector-wide initiatives, will help to address the workforce capacity and capability risk to delivery of our AMP. For an overview of a range of initiatives Orion and the energy sector are taking to address this issue, see Section 9.

Our People and Capability team provides the framework, expertise, and support for this activity, and are the custodians of our workforce plan. They work in partnership with our people leaders who own the outcomes.

For the non-network operational expenditure, see Section 10.

In the following sections we outline the key functions for each Orion team, under the two Commerce Commission Information Disclosure categories for people related operational expenditure:

- Systems Operations and Network Support
- Business Support

We made significant progress in developing our people and capability programme in FY23.

4.3 System Operations and Network Support teams

The system operations and network support activity area covers the teams managing our network, including our Customer Support team and office-based system operations teams. Around 75% of our people are in this activity area.

4.3.1 Future network function

The future network is responsible for the overall direction and management of our network infrastructure to ensure the network is fit for purpose for the future.

It is responsible for strategic and engineering planning for Orion's electricity distribution network, and our customer service activity, infrastructure stewardship, regulation, pricing and billing support.

There are four teams in the future network that deliver system operations and network support activity:

Network transformation and investment team:

- documents our network development plans and forecasts and articulates this through production and publishing of a 10-year Asset Management Plan
- develops appropriate whole of life strategies for our network assets
- monitors, analyses and reports on network performance, network failure analysis and condition of assets
- develops appropriate maintenance and replacement programmes, based on the above analysis
- forecasts changes in customer behaviour and demand
- identifies network constraints, oversees security of supply and develops network and non-network solutions
- provides the planning interface with Transpower
- adapts planning for the impact of emerging technology
- works with developers, consultants, and major customers for new load and generation connections and network extensions

Network transformation programme team:

This team is responsible for delivering Orion's Network Transformation Roadmap. Key deliverables include:

- enhancing the sustainable connection of new technology to our distribution network
- enabling the trading of energy and capacity between customers and market participants via an open network framework augmenting our planning, investment and operational requirements to achieve Orion's Network Transformation Roadmap

Asset and spatial intelligence team:

- manages and develops our network asset register and geospatial systems to ensure our network asset data is accurate and available for the effective management of our network
- manages the content, review and dissemination of certain controlled business documents, internally and externally
- manages and develops systems and procedures to ensure accurate network reliability statistics
- provides data insights

Customer and communications – customer support team:

Our customer support team is a key point of contact for our customers. The team:

- operates 24/7 and responds to more than 1,800 calls from customers each month
- provides a point of contact for our customers seeking the help and reassurance of a real person
- provides customers with information about power outages, resolves complaints and assists with the supply of our services

Orion Development Programme:

This programme encompasses our technical trainee, summer internship and graduate streams. The programme mentors and develops our people as they progress through their focussed training.

The balance of our Future Network teams are in the Business Support category, see Section 4.4.

4.3.2 Electricity network function

Our electricity network is responsible for the daily operation of the network, delivery of AMP work programmes, and other delivery and engineering related services including business process improvement.

Engineering team:

Our engineering team provides support with engineering or technical issues and explores new opportunities to improve our network management. The team:

- focuses on ensuring a safe, reliable, resilient and effective network
- ensuring operational systems are fully scoped, tested and supported throughout their lifecycle; while also looking for opportunities to improve and optimise our operations of these systems.
- sets and maintains standards for materials and applications and maintains documentation associated with establishing, maintaining and developing our network assets
- researches and reviews new products and alternative options with a view to maximising network safety and reliability and minimising lifetime cost
- researches and evaluates latest trends in maintenance and replacement of assets
- investigates plant failure, manages protection setting data and keeps the integrity of control and protection systems at high levels
- works with our service providers when developing commissioning plans and the introduction of new standards and equipment
- analyses technical data and acts on the information to minimise the risk of loss of supply to network
- manages and maintains our key operational platforms

Network delivery team:

This team oversees programme management, works delivery, customer connections, procurement and land services, and fleet management.

The team:

- ensures the delivery of Orion's planned and unplanned works on overhead, substation and underground assets via our Primary Service Delivery Partner (PSDP), Connetics, via a dedicated arms-length Project

Management Office (PMO) which plans and procures work from Connetics and independent service providers

- is responsible for the establishment of the programme of works and monitoring of works through the PMO, for instance the team:
- identifies required works and develop scopes, works specifications and designs that meet our network standards and specifications
- ensures the work packages are suitable for delivery
- monitors the completion of works to our budget as set out in the AMP
- responsible for procurement and works management of some functions including management of Orion's property assets, from kiosks to substations to office buildings
- manages our vegetation management programme
- undertakes other civil related and consultancy services
- ensures Orion gets value for money and the level of service we expect from the services we contract in as well as securing Orion's property and consenting interests

Customer connections team:

The customer connections team welcomes new customers to our network. The team:

- ensures customers are connected to the electricity network in a safe and cost-effective way
- manages power quality – investigates complex Orion and customer network issues. Analyses voltage disturbance and deviation problems, predominantly in industrial and commercial customer groups, while offering support and education
- manages distributed generation –reviews and approves customer connected generation. Ensures safe connections

4.3 System Operations and Network Support teams continued

- manages street lighting and new technology connection management. Develops and maintains Distributed Unmetered Load Data Base for major customers. Ensures accuracy and integrity of street light data on GIS
- provides low voltage management – enables safe switching operations to be carried out on Orion's network through accurate schematics and site identification
- creates and supports business processes to enable accurate updating of GIS
- manages HV labelling – enables safe switching operations to be carried out on Orion's network through site and network circuit identification
- manages Orion-owned generators to ensure safe operation. During disaster recovery, provides a specialised team to work independently from the network to enable generator power restoration to communities
- undertakes technical surveys and provides concise and simple reporting
- provides service providers and the public with safety advice and education for those working close to or around Orion assets
- reviews applications and issues, as appropriate, close approach consents to Orion-authorised service providers, third party service providers and members of the public who need to work closer than four meters from our overhead lines and support structures

Network operations team:

Our network operations team includes our control centre, operations planning, field response, and network access teams. The team:

- monitors and controls our electricity network in real time, 24/7
- provides safe network switching and fault restoration
- utilises load management to minimise peak load and maintain security
- provides load management assistance for all upper South Island EDBs
- operates high and low voltage switchgear
- provides a first response to network and customer faults
- makes safe network equipment and customer premises for emergency services
- repairs minor faults

Network access team:

- coordinates and approves access to our network, including setting standards and writing training and assessment material for both employees and authorised service providers
- trains and assesses the competency of employees and service providers to enter and work in restricted areas, and to operate our network
- maintains a database of competencies held by every person accessing and working on our network
- develops operating manuals for equipment used on our network, and support material for our network operators

Release planning team:

- coordinates and approves service provider requests to safely access the network to carry out planned work

Health and safety team:

The health and safety team ensures we work safely and our community can be confident Orion contributes to a safe and healthy environment. The team:

- provides health and safety governance and legislative overview
- provides continuous health and safety system improvements
- provides health and safety advice to Orion Group and other key stakeholders
- administers Vault, our incident and safety management system
- leads significant investigations – using the Incident Cause Analysis Method (ICAM)
- contributes to health and Orion Group training and coaching initiatives
- provides analytical reporting to the Orion Group leadership team and board
- works pro-actively with industry and peak bodies to build capability
- provides a process for close approach consents for all third parties including the public and service providers operating in close proximity to Orion's electricity network

4.4 Business Support teams

The business support activity area manages the support systems, processes, engages with our customers and explores future business opportunities to ensure we deliver present and future value to our customers and stakeholders. Around 25% of our people work in this area. The teams in this area are:

4.4.1 Purpose and performance function

This function drives The Orion Group to achieve our Group Strategy, and includes:

People and capability team:

This team provides strategic, tactical and operational support and advice to Orion's people leaders. The team administers Orion's payroll function. By supporting our leaders and managers to build capability and performance we seek to achieve the best organisational results through our people.

Sustainability and risk team:

The team undertakes strategic initiatives, industry collaboration and operational reporting in support of powering a low carbon economy. The team measures and reports on our carbon emissions, is actively involved with carbon insetting and offsetting activities, and reports on the opportunities and risks associated with climate change. The team also supports and monitors the business in the area of enterprise risk management.

Operational excellence team:

The team supports driving business improvement and grow strategy execution maturity.

4.4.2 Value optimisation function

Value optimisation works to ensure we deliver value for our customers and stakeholders.

Finance team:

This team is responsible for financial reporting and management. It is also responsible for treasury, tax and tax compliance, regulatory reporting, budgets, accounts payable and receivable, financial forecasting, job management, financial tax and regulatory fixed asset registers and support for financial systems. Our Privacy Officer is a member of this team.

Value optimisation services team:

Other services include business improvement, administering Orion's internal audit programme and value, innovation and commercial and financial analysis.

4.4.3 Future network function

Regulatory and commercial team:

This team's responsibilities include pricing, government policy and regulation, billing and major customer support. This team leads:

- our advocacy, engagement and submissions to MBIE, Climate Change Commission, Ministry for the Environment and Infrastructure Commission
- our engagement with and submissions to the Commerce Commission, Electricity Authority and other industry regulators
- our network delivery pricing approach, compliance reporting
- billing to retailers and major customers

Customer and communications team:

This team is responsible for engaging with our customers and key stakeholders, to:

- identify their needs and work with our business to ensure we can best meet these needs
- build key community relationships to enable us to deliver on our strategic community objectives
- lead internal and external communications including public relations and social media
- The team also focuses on improving our customer service by:
    - understanding our customers' needs
    - co-creating service offerings with our customers and partners

4.4.4 Digital, data and technology function

Digital, data and technology was established in FY23 to bring a strategic, Group level view on data governance and digital system evolution in support of improved decision-making, advanced analytics, system control, business outcomes and customer centricity.

Data intelligence team:

The data intelligence team is responsible for delivering business insight through:

- developing robust data governance frameworks to deliver a modern data platform
- builds new data ecosystems through the application and deployment of analytical tools
- promotes data driven decision making across the organisation
- explores and implements advanced analytics and the use of AI and machine learning

4.4 Business Support teams continued

Technology and platform services team:

The technology and platform services team is responsible for architecting, delivering and operating enterprise, digital and productivity systems and platforms through:

- leading the business in the selection and delivery, ongoing configuration, integration and management of our information systems. This includes standalone applications, data and computing platforms, and all supporting infrastructure
- delivering business automation through digital service development and use
- providing tier one to tier three support for systems
- ensuring robust cyber security practices and controls are in place and continuously improved
- partnering with vendors and expert third parties to augment in-house Orion information technology services

Project support office:

- provides governance, guidance and a consistent delivery framework to support best practice project delivery

4.4.5 Growth and development team

The growth and development team is responsible for:

- identifying, establishing and scaling business models and technologies that are new to Orion
- developing and delivering commercially viable business opportunities with a strong commercial value focus
- providing commercial energy and renewable engineering advisory services to business
- energy solutions architecture based on customer and network insights

4.4.6 Energy futures team

The energy futures team is responsible for:

- exploring future energy markets and business models
- future energy strategy
- leading exploration of innovation functions i.e. leveraging existing business models and technologies
- energy market insights and analytics
- exploring community energy solutions to support energy equity

4.4.7 Governance team

The governance team is responsible for:

- our insurance programme, which is designed to manage our key risks
- governance reporting and support to the Board of directors
- managing our corporate policies and legislative compliance programme

4.5 Information technology strategy

Orion is transforming our operating model to become an increasingly digital business, modernising our core platforms and leveraging digital services, automation and data intelligence to drive business performance and improve customer outcomes. Shifting to a more digital operating model improves our operational efficiency and enables us to address the more complex and dynamic energy future. The key elements are:

- Enablers: Data intelligence, cloud services, integration and AI
- Modernised core: Investing in the core systems to enable Integrated Asset Management and operational efficiencies
- Digital workplace: Automation, productivity and digitisation of process and channels
- Service delivery: Enabling modern ways working and improved service delivery
- Cyber security: Securing our increasingly digital organisation and assets

For more detail on the changing environment in which Orion operates, and the Orion Group strategy, see Sections 2 and 4.

4.6 Systems overview

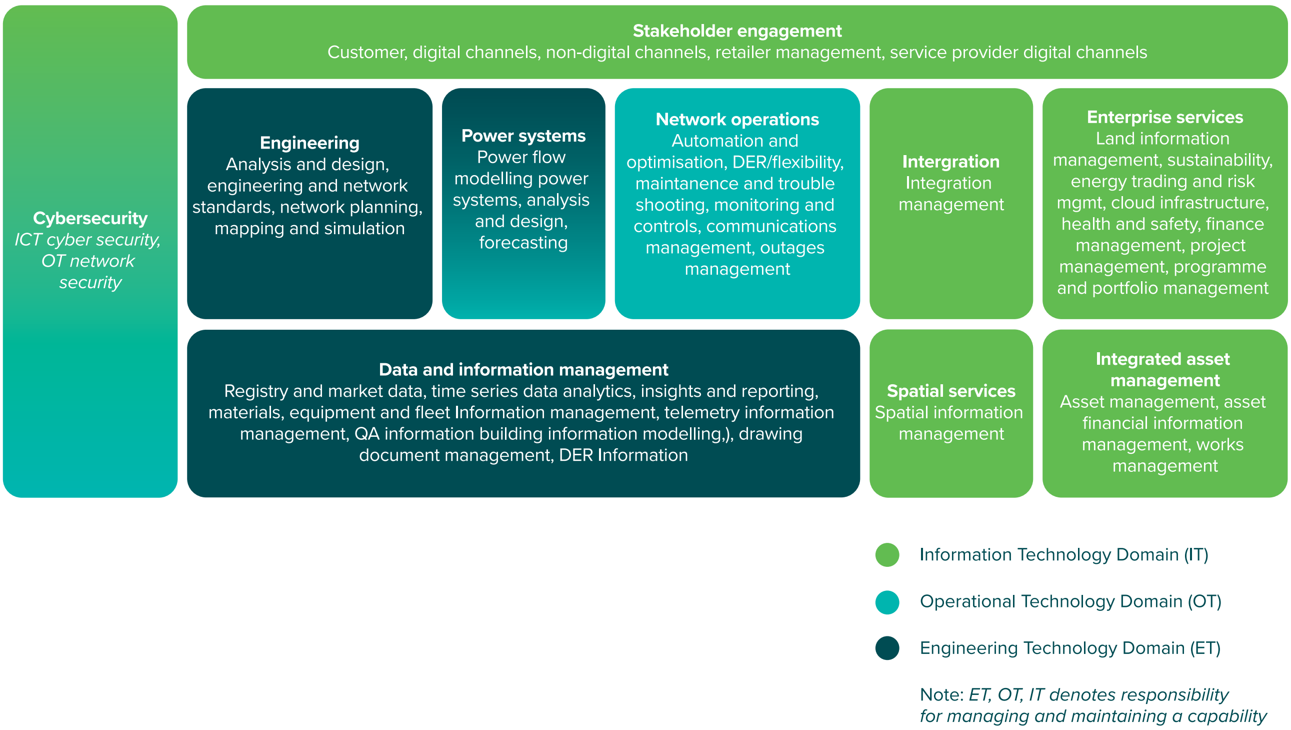
Orion has a range of information systems that together support the operation of our network. These systems are categorised into three areas:

- **Information Technology (IT)** – systems which provide core enterprise information and communications technology services and data for operational technology and engineering technology
- **Operational Technology (OT)** – systems used to monitor, manage and operate the network
- **Engineering Technology (ET)** – systems used to define, design, simulate, analyse, visualise and validate for planning, design, problem-solving and decision-making purposes

Each group of systems has distinct functions and some overlap due to the convergence of our technologies and data platforms. In this section, we outline our systems, what they do and how they interact with each other. Figure 4.6.1 shows Orion's key business functions and their information systems needs that are supported by digital technology.

For each business function we describe how we are aligning our digital architecture of core platforms to support their work, outline the non-network assets, and our planned upgrades over this AMP 10-year period.

Figure 4.6.1 Orion business functions and their activities supported by digital technology



4.6 Systems overview continued

We will architect and deliver these digital business functions through a business partner approach based on these principles:

- Ensuring digital investments are strategically aligned and delivering business value.
- Ensuring the services delivered are fit for purpose, and features are delivered according to Orion Group priorities and our Network Transformation Roadmap.
- Enhancing vendor management practices to align costs to organisational and business unit appetite for investment.
- Looking outside of our business for digital innovation and partnering to identify, test and apply innovations.

We have started a multi-year programme to replace current asset management tools with enterprise grade asset management and modelling tools.

In the following sections we provide a summary of the systems and platforms within each operational area. Where we have identified systems to be upgraded or replaced over the AMP period, we have provided an overview of their current limitations and the envisioned future state.

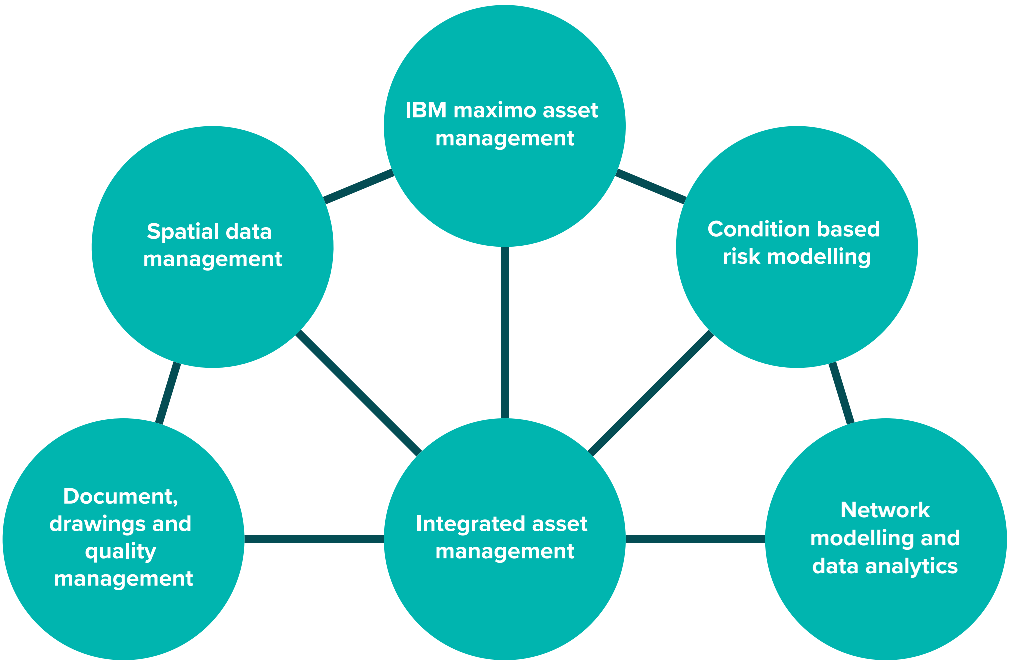
4.6.1 Integrated asset management and spatial services

Data and information is essential for asset management decision-making and modern digital platforms that can provide accurate and timely data and information are key. Many of Orion's current systems supporting our asset management processes are end of life. Our goal is to modernise the systems supporting the management of our network and uplift our asset management capabilities.

We have started a multi-year programme to replace current asset management tools with enterprise grade asset management and modelling tools. This programme will focus on implementation of IBM Maximo for core asset management, implementing new condition-based risk modelling and upgrading our finance and spatial systems. For a description of Orion's asset management platforms, and planned replacements, see Table 4.6.1. We expect this programme to deliver an overall improvement in productivity and efficiency, and readiness for broader Artificial Intelligence (AI) use.

Within its Integrated Asset Management Strategy, Orion takes an interconnected, enterprise approach, see Figure 4.6.2.

Figure 4.6.2 Orion's interconnected enterprise approach to integrated asset management



4.6 Systems overview continued

Table 4.6.1 Programme to replace main asset management platforms

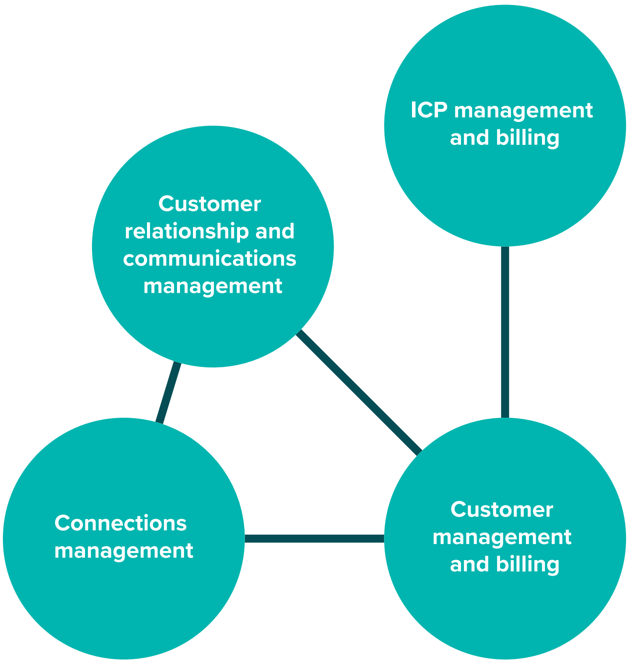
Platform	Description	Replacement programme
Asset management information repository	Our asset repository holds information describing our network assets. We extract schedules from this repository for preventative maintenance contracts and network valuation purposes.	We are replacing our existing asset management systems with an Integrated Asset Management (IAM) strategy based around IBM Maximo.
Spatial management systems – GIS	Our Geospatial Information System (GIS) records the location of our network assets and their electrical connectivity. It is one of our integrated asset management systems. Full access to the GIS is continuously available to the Orion team through locally connected and remote viewing tools. Tailored views of GIS data are also available to authorised third parties via a secure web client.	Our GIS platform is mature and approaching end of life and we will select and deploy a replacement solution as part of our Integrated Asset Management programme of work.
Condition Based Risk Management (CBRM)	CBRM is a spreadsheet-based modelling program that uses asset information, engineering knowledge and experience to define, justify and target asset renewals.	Our Current CBRM tools are end of life and as part of our IAM strategy we will be replacing our current CBRM modelling tooling.
Works Management	Currently all works activities are managed using an in-house application, Works Management.	Works Management is end of life and we will replace it in the first tranche of projects as part of our IAM strategy.
Document, Drawings & Quality Management	Our document, drawing and quality management systems are currently delivered via end of life in-house bespoke solutions and the document management system, SharePoint.	As part of our wider IAM strategy we will replace the bespoke solutions with an industry-grade drawings, quality, and document management solution.

4.6.2 Customer engagement

Our Customer Relationship Management (CRM) platform is now firmly embedded into our business. CRM now supports several processes that manage interactions with our customers, including close approach consents and new connections. Along with on-going CRM implementation, we are modernising our customer billing platform. These two platforms will enable Orion to develop and enhance functionality that will benefit our customers. Figure 4.6.3 shows our connected enterprise approach for stakeholder engagement.

Our Customer Relationship Management (CRM) platform is now firmly embedded into our business.

Figure 4.6.3 Customer engagement integration



For a description of Orion's customer and billing platforms, and planned replacements, see Table 4.6.2.

4.6 Systems overview continued

Table 4.6.2 Orion billing and customer interface platforms

Platform	Description	Replacement programme
Billing	Our billing solutions have been reviewed in light of our pricing strategy and move to ICP billing as well as meeting future regulatory and complex customer requirements.	Our current billing solutions are end of life. We are implementing a new billing system which will go live in early FY25. Our new billing platform will be delivered by Axos and will support management of connection information, calculation of delivery charges and monthly invoicing to energy retailers.
Customer Relationship Management (CRM) and website	We are continuing to build out our CRM system as the primary platform for delivery of services to our customers. In FY24 we completed two phases of delivery of our CRM platform which delivered enhanced power outage and new connections management functionality to our business and customers. We also completed a lifecycle upgrade to our Customer Support centre solutions. Our website was developed in 2014, and is not readily able to support new information, enhanced online services to customers and service providers, or provide a modern user-friendly interface.	Our next phase of CRM delivery will focus on enhancements to phase one and two deliveries and customer management. We will also upgrade our web content management platform, the Orion Group website in FY25.
Connections Management	As part of our CRM phase two rollout, we migrated connections management to the Dynamics CRM platform. Our Connections Register, which links to the Industry Registry, holds details of all Installation Control Points (ICP) on our electrical network. There is an interface with our GIS systems that enables accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are routinely traced within the Advanced Distribution Management System (ADMS) for the high voltage network and the GIS for the low voltage network using the in-built connectivity model. Accurate information about the number of customers and interruption duration are recorded and posted in near real-time to Orion's website.	We will continue to enhance connections management as part of phase three of the CRM program during FY25.

4.6.3 Enterprise services

Our enterprise services support all Orion business units by providing core systems that supports business operations. For a description of Orion's enterprise services systems, and planned replacements, see Table 4.6.3.

We are currently modernising our people and capability systems to create an integrated HRIS capability to support business functions.

Table 4.6.3 Orion enterprise services systems

Platform	Description	Replacement programme
IT Service Desk	We recently implemented a new service desk system, 4Me for IT and Enterprise services management.	With the new service desk features now implemented and bedded into the focus for FY25 will be building out enterprise services capability within the tool.
Financial Management	Our Financial Management Information System (FMIS) is Microsoft Dynamics Business Central which delivers our core accounting functions. It includes the general ledger, debtors, creditors, job costing, fixed assets and tax registers. Detailed network asset information is not held in the FMIS. Business Central provides core financial management functions for Orion business units.	Our current FMIS is nearing end of life over the next two years we will upgrade FMIs from on premises to a cloud delivered FMIS solution. As part of this upgrade, we will introduce new functions to increase the digitisation of core business processes.
People and capability management	We have an eco-system service model for our people and culture related capabilities.	We are currently modernising our people and capability systems to create an integrated HRIS capability to support business functions. Projects will include the continued rollout of digital tools to support performance management, learning management, time sheeting, recruitment and development of enterprise service delivery capability.
Health and safety event management	Incidents are recorded, managed, and reported in our safety management system, the Vault Safety Event Portal. This enables incidents and injuries to be captured using a desktop client or in the field using a phone-based application. This system also manages non-staff-related incidents, e.g., incidents affecting our network and customer complaints.	As part of our IAM programme, we will review our health and safety event management systems to ensure they align with current and future business needs.

4.6.4 Network operations

Operational Technology systems help us to monitor and control network equipment, dispatch switching instructions to field crews, and manage network peak demand and pricing signals through ripple control of residential hot water load.

Our Advanced Distribution Management System (ADMS) provides a live operational model of the network, enabling visualisation, scenario planning and advanced features such as automated power restoration and power-flow analysis. These advanced features enable us to rapidly detect faults and restore power for customers and ensure our field crew have the latest information to hand.

Integrated ADMS modules enable mobile switching and job dispatch, as well as providing accurate management of power outages to simplify regulatory reporting. Work is currently underway to develop a live model of our 400V low voltage network within the application, and to leverage the power of automated restoration across wider areas during major network faults.

Our load management systems enable us to control hot water and irrigation load across the network, and this extends to collaborative management of Upper South Island load with other local distributors.

The ADMS system is upgraded approximately every 24 months to remain current with the latest features to enhance security and usability. The Orion load management system is currently in transition to operate within the ADMS, which is a significant technology refresh. This will provide an improved user interface and advanced functionality for future network load management.

For a description of Orion's network operations systems, and planned replacements, see Table 4.6.4.

Table 4.6.4 Orion network operations systems

Platform	Description	Replacement programme
Load Management System	A high-availability Load Management system integrated with the ADMS performs load shedding to reduce the magnitude of our peak load and to respond to Transpower constraints. We also operate and participate in an "umbrella" Load Management system that co-ordinates the load management systems of each of the eight distributors in Transpower's Upper South Island region. This co-operative venture provides a number of significant benefits both to Transpower and to each of the participating distributors.	Orion's load management is currently in transition to the ADMS, providing a more robust and future-proof solution on new technology. The Upper South Island system is a well-established application, due for a technology refresh in late 2024.
We operate an integrated ADMS from GE Digital with three modules: Network monitoring System (SCADA) Network Management System (NMS) Outage Management System (OMS	**Network monitoring system (SCADA)** – our electricity distribution system is monitored and controlled in real time by the SCADA system. SCADA is installed at all zone substations and an increasing number of switching equipment. **Network Management System (NMS)** – a real-time software model of our high voltage distribution network that allows interaction in real time with indication and control devices to provide better information on network configuration and minimise the impact on customers in planned and unplanned outages. **Outage Management System (OMS)** – delivers switching instructions to field operators in real time and returns the actions they have taken.	We upgraded to the latest version of GE Digital's ADMS in late 2023. Much of the hardware was upgraded in 2021. Regular updates and monitoring ensure high-availability, security, and usability. We are progressively installing SCADA at network substations throughout the urban area as we replace old switchgear.

Table 4.6.4 Orion network operations systems (continued)

Platform	Description	Replacement programme
Mobile operating platform (Peek)	Field Operators interact with our Control Systems in real time through an in-house developed mobile application called Peek. An Operator receives operating instructions in the field on a hand-held device and, as each operating step is undertaken, updates the system. The completed operating steps are available for the Control Room to see in real time, and the network diagram is automatically updated.	We upgraded our Peek application in FY23 to enable permit functionality for field crews.
Distribution Power Flow Analysis (DPF)	DPF is a decision support tool for our Network Controllers. It performs network power analysis studies that estimate the state of the network and provides power analysis data to Controllers. DPF studies can run as simulations and what if scenarios include both planned and unplanned work operations.	No planned replacement.
Online release request system	We currently have a largely paper-based manual system for planned outages for network maintenance and development work.	We are currently developing an online release request system to manage our contractor requests to work on the network. This system is expected to be operational in mid-2024 and replace the paper-based manual system.
Interruption statistics	We automatically post outage information from the ADMS OMS into a regulatory reporting database. After checking, the data is summarised along with cause and location in an interruption register. Reports from this register provide all relevant statistical information to calculate our network reliability statistics (such as SAIDI and SAIFI) and analyse individual feeder and asset performance.	No planned replacement.

4.6.5 Cyber security and data privacy

In the context of our Asset Management Plan, our strategy regarding cyber security is focused on the protection of people, processes, data, and systems from cyber security risks.

As Orion continues its digital transformation journey, we navigate an increasing level and complexity of cyber security and data privacy risks. As a lifeline utility, maintaining an effective and mature security system is a key priority and we have an on-going investment to ensure we successfully manage cyber security risks. We have a number of protection systems and processes in place to address the growing threat of cyber security breaches. See Section 5.8.8.

As Orion continues its digital transformation journey, we navigate an increasing level and complexity of cyber security and data privacy risks.

4.6.6 Data, analytics and AI platforms

In FY24 Orion rolled out the basics of our Data, Analytics and Visualisation platform. The platform leverages advanced technologies for big data analytics, Artificial Intelligence (AI), the Internet of Things (IoT), and cloud computing to improve operational efficiency, optimise energy distribution, enhance customer experiences, and drive sustainability initiatives.

This platform will undergo further enhancements to further digitalise Orion assets.

For a description of the components and work programs of Orion's data, analytics and AI platform, and planned replacements, see Table 4.6.5.

Table 4.6.5 Orion data, analytics and AI platform components

Platform	Description	Replacement programme
Data acquisition and integration	The data platform provides an aggregation point for data collected from smart meters, sensors, grid infrastructure and other sources such as weather forecasts. This enables seamless integration of data, ensuring a comprehensive view of the energy distribution network and all its data assets.	Orion's load management is currently in transition to the ADMS, providing a more robust and future-proof solution on new technology. The Upper South Island system is a well-established application, due for a technology refresh in late 2024.
Cyber security and data privacy	State of the art cyber security and data privacy policies, data and model governance, and auditing tools.	A cybersecurity program is underway to enhance current monitoring, mitigation and resolution of cyber security related issues. Robust data security measures such as including advanced encryption, access control, and monitoring are being implemented to protect against potential cyber threats and ensure data privacy. The data platform will provide audited data sharing with internal and external parties. Access will be controlled at user, group and function level ensuring data privacy and local and international regulatory compliance.
Data governance	Part of the platform is the establishment of a data catalogue and associated data governance frameworks.	All data at Orion, including IoT cloud sources, on-prem data assets such as IAM or billing will be brought under a unified governance framework with a focus on improving data quality, policies, stewardship, protection and compliance.
AI, analytics, real-time monitoring	The implementation of AI and advanced analytics tools to process data in real time, analyse large volumes of data, and provide insights to the business faster and smarter.	Real time IoT devices and edge computing will allow Orion to action on insights faster improving a safer more reliable network. Currently we are ingesting millions of records a day and this will grow exponentially over the coming years. Our modern data platform is scalable both in terms of compute and storage to allow the development and deployment of advanced modelling tools and AI applications.
Business intelligence	A fast and reliable BI reporting platform for Orion to bring data to live in interactive reports to increase data driven decision making.	Orion has implemented a PowerBI centred business intelligence strategy with multiple dashboards currently already in production across the business. Moving forward we will implement a major shift in our capability regarding the governance, curation, and delivery of data for business decision making using automated reports, self-service reporting and AI powered analytics and insights.

4.6.7 Engineering and power systems

Our engineering and power systems platforms underpin the analysis, design and maintenance workstreams to ensure the safety, reliability and resilience of our network. They also inform our network investment planning.

For a description of Orion's engineering and power systems, and planned replacements, see Table 4.6.6.

Table 4.6.6 Orion engineering and power systems

Platform	Description	Replacement programme
Network model (design)	An integral part of planning for existing and future power system alterations is the ability to analyse and simulate the impact of network configuration changes offline. This is achieved through using power-flow simulation on an electrical network model. We use a power-flow simulation software package called PSS Sincal and maintain a GIS-derived model of our network from the Transpower connection points down to the HV terminals of our distribution transformers. PSS Sincal also has the capability to model down to individual customer connections on our 400V LV network and run simulations on systems with unbalanced load.	Due to the quality of our low voltage network data, our network model is currently limited to subtransmission and 11kV networks. HV power flow and protection studies are largely carried out manually to identify system issues. We will augment the efficiency of our power flow studies through a combination of off-the-shelf analysis modules offered by Siemens, in addition to custom-built scripts to reduce manual handling for standardised workflows. This will enable our internal resource to focus on more complex scenario analysis and network improvements.
Network model export and load scaler	We use an automated interface developed in-house to enable HV power flow models to be systematically created for PSS Sincal. These models are created by utilising spatial data from our GIS, and linkages to conductor information in our as-laid cables database and customer information in our connection database records. This platform also extracts load data from HV telemetry across our network to scale the model to a desired point in time.	Errors and inconsistencies in the GIS can result in an incomplete network model which requires manual intervention by engineers to resolve. Network configuration changes can also cause a misalignment with network loading data depending on when scaling is applied relative to the GIS data export. Additional error handling and logging will be implemented to identify issues in the source data for correction. The model creation process will have the capability to fill data gaps in the case of non-critical errors. We are also investigating the feasibility of IEC CIM to act as a transfer medium between GIS and PSS Sincal for network modelling. This has the benefit of growing compatibility between a variety of other platforms to support collaboration with third parties.
Network loading database	Data from our HV network telemetry devices is maintained within a database of well over 100 million half-hour loading values. This is available for trend analysis at a wide range of monitoring points in our network. The database also includes Transpower grid injection point load history and major customer load history. Several tens of thousands of new data point observations are being added daily. Half hour network feeder loading data is retrieved from the SCADA historical storage system. This data is analysed to derive and maintain maximum demands for all feeders monitored by the SCADA system. Loading data is also archived for future analysis.	The Network Loading application is a custom-built piece of legacy software which cannot be easily updated or maintained. We are investigating whether it is possible to shift this database to an alternative platform without sacrificing its functionality.

4.6 Systems overview continued

Table 4.6.6 Orion engineering and power systems (continued)

Platform	Description	Replacement programme
Network analytics platform	As part of a wider strategic initiative associated with the future operation of our low voltage network we have implemented a new cloud-based data platform for collection, storage and analysis of LV monitor, smart meter data and other network data sources.	We are trialling several third-party analytics platforms to supplement our internal development.
Analysis and design tools	Apart from specialised power flow modelling software, we utilise a variety of other tools for network analysis, asset capability calculations and design such as Excel, QGIS, Matlab, MathCAD and Python.	No planned replacements.
Computer aided design	AutoCAD and Bentley are commonly used software platforms used for computer aided design in our industry. AutoCAD is widely used by our design consultants and service providers which allows for ease of transfer and quality control. We use AutoCAD for the design of zone substations and other assets that can't readily be represented in our GIS system. We also use Bentley MicroStation for the design and upkeep of our network diagrams.	These software tools will form part of our future Integrated Asset Management ecosystem.
Drawing management system	We have a bespoke system that is a database of all current and historical drawings, it manages version control, and the issuing and checking back in of drawings to Orion people, design consultants and service providers	We will research and trial new and good practice software platforms, tried and tested in our industry, to enable better version control and field updating by our service providers. This will help us to maintain and enhance quality and version control. This will also form part of our Integrated Asset Management journey.
Protection settings and device management	We use a software package known as StationWare to store information and settings for all our protection devices. The software also manages version control by Orion staff and our service providers, and integrates with our ADMS to provide information such as overload limits for assets.	The StationWare software is reliable, and we have no plans to replace it, however, we will seek to enhance it in line with any improvements proposed by its provider.

4.6.8 Business information and productivity systems

Our corporate business information systems and productivity software support processes across Orion. Our supporting computing infrastructure hosts, connects and provides access to our information systems. In most cases we manage our computing infrastructure in-house because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on our electricity network.

For a description of Orion's infrastructure supporting our information systems, and planned replacements, see Table 4.6.7.

Table 4.6.7 Orion business information and productivity systems

Platform	Description	Replacement programme
Email system	The capacity and performance of our email system is adequate for the period of this plan if there are no major changes required. Our email system is a mature and well established application.	No planned replacements.
Workplace collaboration systems	We use Microsoft Teams and Workplace to support new ways of working and sharing information across our teams.	No planned replacements.
Desktop/ laptop clients and operating systems	Our choice of operating system and desktop software capacity/performance are adequate for the duration of this plan. The desktop operating system is current and subject to regular security and performance updates from Microsoft. Changes may be forced on us in the future as new equipment becomes unsupported on the current version.	Lifecycle replacements.
Replicated computer room	We operate two Transportable Data Centres linked by diverse fibre networks which are both performing to expectations.	No planned replacements.
VM and SAN	Our VMware Virtual Server and Storage Area Network infrastructure is managed through a lifecycle and regularly upgraded before performance issues arise or warranties expire. Capacity and performance are adequate for the duration of this plan.	No planned replacements.
Physical servers	We still occasionally use individual physical service for specific applications. As with all Orion infrastructure we manage these servers through a lifecycle.	The health of these servers is monitored and we typically replace servers of this type in three to five years.

4.7 Digital, data and technology expenditure forecast

Our Digital, data and technology team delivers technology platforms, application services and data insights that support the Orion distribution network. Many of these systems are supported directly by the team through vendor agreements for third party support where appropriate. License costs provide a degree of application support but are largely a prepayment for future upgrades.

4.7.1 IAM and GIS expenditure forecast

We are about to undertake a significant multi-year capital investment programme to modernise our asset and spatial management systems. These investments will focus on both technology and business capability to fully digitise and drive efficiency in how we manage Orion's assets over the next thirty years in an increasingly complex energy environment. Through the digitisation of asset data, we increase our ability to leverage asset condition and inspection findings, which enables Orion to make smarter, risk-based asset investment decisions. This improved data analysis means we can optimise our investments and allocate our expenditure more effectively and efficiently.

4.7.2 Other expenditure forecast

In addition to the capital investment in asset and spatial management, we will also undertake a programme to further enhance the digitisation of business support and data management systems. This includes the automation of processes, flex infrastructure and the utilisation of artificial intelligence (AI). This requires both capital and operational expenditure in both network and none-network areas.

For network related activities, capital investment will improve asset digitisation, onboarding of platforms for flexible service providers and integration of collaboration with external parties and platforms.

Non-network related capital expenditure activities include the enhancement of automation processes, data reporting services and further roll out of technology that facilitates communication between devices and the cloud, and edge computing applications.

Operational expenditure for both network and non-network related activities includes the cost of cloud subscriptions, process enhancements and additional data services integration.

See Section 10 for the expenditure forecast over the planning period.

Through the digitisation of asset data, we increase our ability to leverage asset condition and inspection findings, which enables Orion to make smarter, risk-based asset investment decisions.

4.8 Modernising asset information management

To support our development of an integrated asset management system, we have identified the need to modernise information we hold on our assets and the processes and business functions supporting it.

Accurate, up-to-date, and accessible asset information is essential for Orion to deliver on our 10-year Asset Management Plan. As we expand our infrastructure and technological capabilities, the complexity of our asset portfolio grows. Over the next few years we will improve modernising asset information management which will deliver these benefits:

- **Improved decision-making** – access to real-time asset information empowers decision-makers to make informed choices about maintenance, repairs, upgrades, and replacements. Timely data enhances predictive analytics, allowing for proactive measures to avoid network interruption and mitigate risks.
- **Regulatory compliance** – for many of our assets, compliance with regulatory standards is mandatory. Modernising asset information management will help us track and demonstrate adherence to our industry-specific regulations.
- **Resource optimisation** – efficient allocation of resources relies on accurate asset information. Modern systems enable organisations to identify opportunities, leading to cost savings and improved resource allocation and utilisation.
- **Lifespan maximisation** – well-managed asset information facilitates effective maintenance scheduling, extending the lifespan of assets. This ultimately reduces replacement costs and contributes to our sustainability efforts.

To modernise our asset information, we have a series of projects within the Integrated Asset Management programme:

- **Data model design** – through alignment with industry benchmarks, best practice and industry counterparts, we will develop a new asset data model designed to deliver on the shifts we need to make in our asset management practices.
- **Data centralisation** – we will establish a centralised digital repository for all our asset related data.
- **Digital twin technology** – we will utilise digital twin technologies to create virtual replicas of our physical network. This will enable simulation, monitoring and analysis of asset performance.
- **Data analytics** – our data intelligence and discovery functions will continue to deliver insight and spatial analysis to improve decision making and operational understanding.
- **User training** – we will continue to invest in user training to ensure our people effectively utilise the modern asset information management environment.

Our document and drawing control practice is also important for the efficient and effective asset information management. We two programmes of work to provide improvements to this knowledge management:

- **Taxonomy re-design** – we are rebuilding our controlled document taxonomy to better reflect the business function.
- **Storage** – our document control storage is handled by SharePoint and this will be reviewed and improvements implemented within the life of this plan. Migration to a complete knowledge management platform will be considered.

4.9 Asset data integrity

In alignment with our ongoing modernisation of our asset information, we have processes and practices to ensure asset data integrity. As quality asset information is vital as a foundation for our lifecycle analysis, we currently practice the following assurance activities and check points:

- **Data governance framework** – our robust data governance framework outlines data ownership, responsibilities, quality standards, and access controls as a part of our data intelligence workstream.
- **Data auditing** – we regularly conduct data audits to identify anomalies, discrepancies, and information changes. Auditing ensures our data remains accurate and complies with our network standards.
- **Standardised data entry** – we have standardised data entry procedures to prevent typos, inconsistencies, and duplications. This includes using predefined data fields and controlled vocabularies wherever possible.
- **Access controls** – we have role-based access controls to restrict data modification to approved team members only.

5 Managing risk

Photo: Connetics crew laying a new 66kV cable to increase the capacity and resilience of the power network to support growth in Belfast and northern Christchurch.

Contents

5.1 Introduction

In this section we set out Orion's approach to managing the risks associated with managing our network and the environment in which we operate.

We outline our risk assessment processes and list our top ten risks and the strategies we use to mitigate them.

5.2 Our approach to risk management

Orion Group takes an Enterprise Risk Management (ERM) approach. This helps us to offer a safe, reliable and sustainable electricity delivery service. We maintain a comprehensive and cohesive risk focus across our organisation, effectively addressing both strategic and operational risks.

The ERM approach also enables us to make informed decisions based on a balanced view that includes evaluating promising opportunities to build a more sustainable and resilient energy future.

Our ERM programme:

- aligns with the Orion Group's Purpose, Strategy and objectives
- fosters community aspirations for liveable region with connected communities, a healthy environment and a prosperous economy
- enables effective identification and management of significant and emerging risks
- facilitates clear decision-making on opportunities inherent in specific risks
- drives continuous improvement efforts

Our approach to ERM is grounded in our belief that:

- every person has a responsibility to identify and mange risks
- a healthy and collaborative culture is a vital part of our risk management
- risk management relies on good judgement, supported by sound evidence
- risk management is all about creating and protecting value for our customers, our community, our people and our other key stakeholders
- continuous improvement is an ongoing commitment in our approach to risk management

5.3 Our risk context

We operate in a dynamic environment that creates a more fluid mix of risks and opportunities than ever before.

Electricity is a fundamental necessity powering modern society. As our community embraces the transition to a low carbon economy to tackle the climate emergency, the demand for electricity is expected to soar, and our role in the energy sector to change and grow. The energy sector is facing significant challenges as it undergoes a transformative period of change. The need to address climate change, modernise infrastructure, ensure equitable energy access, and adopt sustainable practices requires collaborative effort from government, industry stakeholders and society as a whole. Amidst these challenges, technological innovation and advancements provide opportunities to build a more sustainable and resilient energy future.

As a lifeline utility, it is vital we recognise and effectively manage the primary risks associated with our business.

Our community's dependence on electricity becomes even more pronounced during High Impact Low Probability (HILP) events such earthquakes. As stated in section 60 of the Civil Defence Emergency Management Act, our status as a crucial lifeline utility mandates that we maintain operational functionality to the greatest extent possible, even if it means operating at a diminished capacity, during and in the aftermath of an emergency.

As a lifeline utility, it is vital we recognise and effectively manage the primary risks associated with our business.

5.3 Our risk context continued

As further context, our service region:

- has a high risk of earthquakes. Research indicates there is a 75% probability of an Alpine Fault earthquake occurring in the next 50 years, and a 4 out of 5 chance it will be a magnitude 8+ event
- has cold winters, commonly with severe weather conditions, such as snow and windstorms
- has very limited availability of natural gas through pipelines
- has strict regulations on using solid fuel heating due to clean air restrictions

We also know that:

- we are in the midst of a climate change emergency and there is increasing urgency to address this issue and report on our adaptation plans
- our customers will increasingly convert from fossil fuels to renewable energy sources
- the availability of a workforce with the skills and capability to deliver and support this increased activity in the electricity sector is constrained
- global risk sources such as pandemics, cyber-crime and geopolitical conflict are increasing in their likelihood and potential consequences
- the pace of technology change will continue to increase
- other lifeline utilities in our region depend on electricity, and this interdependency is important
- electricity distribution networks have specific hazards and risk sources by their very nature
- Electricity Distribution Businesses and the wider electricity sector are highly regulated
- The Energy Companies Act requires that the principal objective of an energy company shall be to operate as a successful business
- we are publicly accountable to our customers, our community, our shareholders, and regulators
- our shareholders are also publicly accountable to our community

5.4 What our community wants from us

We take our customer's views and priorities into account in our network development planning and risk assessments.

In our 2023 "Powerful Conversations" workshops with customers, they clearly identified their top priority for investment in our network should be building resilience to reduce the likelihood and duration of power outages as a result of severe weather or other major events. Both our rural and urban customers would also like to see fewer disruptions to their power supply and power restored as quickly as possible.

For more detail on what our customers are telling us about their attitudes to risk, our service performance and other factors impacting them, see Section 3.5.

We take our customer's views and priorities into account in our network development planning and risk assessments.

5.5 Our approach to risk management

5.5.1 Our enterprise risk management process

Our ERM process is consistent with the international risk management standard ISO 31000:2018.

5.5.2 Our risk management appetite

When it comes to health, safety and significant operational risks, we maintain a conservative approach to risk management. When we evaluate our remaining risks, we consider the potential benefits and how we might manage our response to make the most of the opportunities they offer.

5.5.3 Management of our climate change risks and opportunities

Climate change presents both challenges and opportunities alongside the impacts it has on our physical environment and operations. To effectively deliver on our Purpose – Powering a cleaner and brighter future with our community – we must assess the inherent risks and opportunities in our business strategy, government policies, or investments to align with our community's efforts to reduce carbon emissions.

We group the risks and opportunities arising from climate change into three categories:

- **upside growth opportunities** — resulting from increasing demand for renewable energy sources to replace fossil fuels such as coal, gas and transportation fuels. Increased opportunities for automation also create the opportunity for a more robust energy system facilitated by distributed energy resources. This provides us the chance to contribute to an efficient, inclusive, and resilient energy network capable of withstanding future challenges.
- **physical risks** — these risks can be triggered by event-driven factors such as more frequent and severe storms, as well as gradual long-term changes like rising temperatures and sea levels.
- **transition risks** — these can be broader shifts resulting from social, legal or policy changes steering away from the use of fossil fuels. Such risks are typically classed as strategic impacts.

For more detail on our assessment of the impact and approach to the risks and opportunities related to climate change, see Orion's Climate Statement, available on our website.

Overall, we continue to believe that the growth opportunities resulting from climate change will outweigh our physical impact and transition risks over the next ten years.

5.5.4 Our network risk management

We are diligent and forward-thinking managers of Central Canterbury's electricity distribution network. We continuously improve how we:

- forecast customer demand for our services including considering the potential effects of new technologies, climate regulation, and our evolving environment
- plan and build for network safety, capacity, reliability and resilience
- monitor, maintain and upgrade our key assets and systems through our ongoing lifecycle management
- operate, monitor and approve access to our network
- maintain an appropriate level of backup systems and emergency spares
- nurture and advance the capability of employees and service providers
- undertake an effective vegetation management programme
- otherwise identify, assess, and manage our key risks

Our sector's attention to addressing the workforce shortage issue, and Orion's initiatives to create an environment where our people can grow and thrive, are important measures helping to manage our people risk.

5.5.5 Our people risk management

Our aspiration is to be an employer of choice, and one of Orion's five strategic focus areas is creating the preferred workplace.

With a workforce in high demand locally and internationally, we recognise that attracting and retaining people with the capability and in the numbers we need is essential to Orion being able to deliver the programme of work in this AMP.

We are also conscious that in their work across every aspect of our business, our people help us to identify and mitigate risk.

To effectively manage both aspects of our people risk, we are proactive and conscientious in our efforts to achieve:

- a healthy and safe workplace
- a resilient and engaged workforce
- a collaborative, diverse and inclusive culture
- effective employee recruitment and retention processes
- effective capability development and training
- effective long-term succession planning

We also support wider industry competency initiatives to address the growing need for people with the rights skills to serve the increase in demand for electricity, driven by decarbonisation. For example:

- the Energy Academy
- the Ara Trades Innovation Centre, which has an electricity distribution trades training centre
- the University of Canterbury's Power Engineering Excellence Trust

Our sector's attention to addressing the workforce shortage issue, and Orion's initiatives to create an environment where our people can grow and thrive, are important measures helping to manage our people risk. For more detail on how we support and develop our people, see Section 5.

5.5.6 Our commercial and financial risk management

Our revenue supports ongoing investment to meet the long-term interests of our shareholders, customers and communities. We manage our commercial and financial risks through:

- providing great service
- appropriate delivery service agreements and constructive engagement with electricity retailers and major customers
- active engagement with regulatory agencies
- prudent financial policies and procedures
- robust internal controls including a business assurance programme

5.5.7 Our regulatory risk management

The electricity industry is highly regulated, via multiple regulatory agencies. We aim to comply with our obligations and to constructively engage with agencies on key regulatory developments.

5.5.8 Our insurance

To transfer some of our financial risk, we have the following insurances in place – consistent with good industry practice:

- our material damage insurance policy insures us against physical loss or damage to specified buildings, plant, equipment, zone and distribution substation buildings and contents – and is based on assessed replacement values
- our business interruption insurance policy indemnifies us for increased costs and reduced revenues as a consequence of damage to insured assets – with an indemnity period of 18 months
- we have several liability policies — including directors' and officers' professional indemnity, public liability, statutory liability and contract works

Our key uninsured risks, which are effectively uninsurable for all Electricity Distribution Businesses (EDBs), are:

- lost revenues – although the Commerce Commission now allows EDBs to recover uninsurable lower revenues from customers in later years. This ability to recover is capped at 20% of annual delivery revenues
- damage to overhead lines and underground cables outside of substation boundaries

We also require our key network service providers and suppliers to have appropriate insurance for:

- third party liabilities
- plant and equipment
- motor vehicle third party
- product liability

5.6 Our risk management responsibilities

5.6.1 Our everyday risk management

Orion's board of directors oversees the key strategic and operational risks that have the greatest potential to adversely affect the achievement of our objectives. Management reports to the board on key risks, emerging risks and environmental context.

Orion's board of directors oversees the key strategic and operational risks that have the greatest potential to adversely affect the achievement of our objectives.

5.6 Our risk management responsibilities continued

We also seek independent expert advice when appropriate. Our everyday risk management is mostly handled by line management as part of their normal duties. We also have four teams that support line management to undertake risk management:

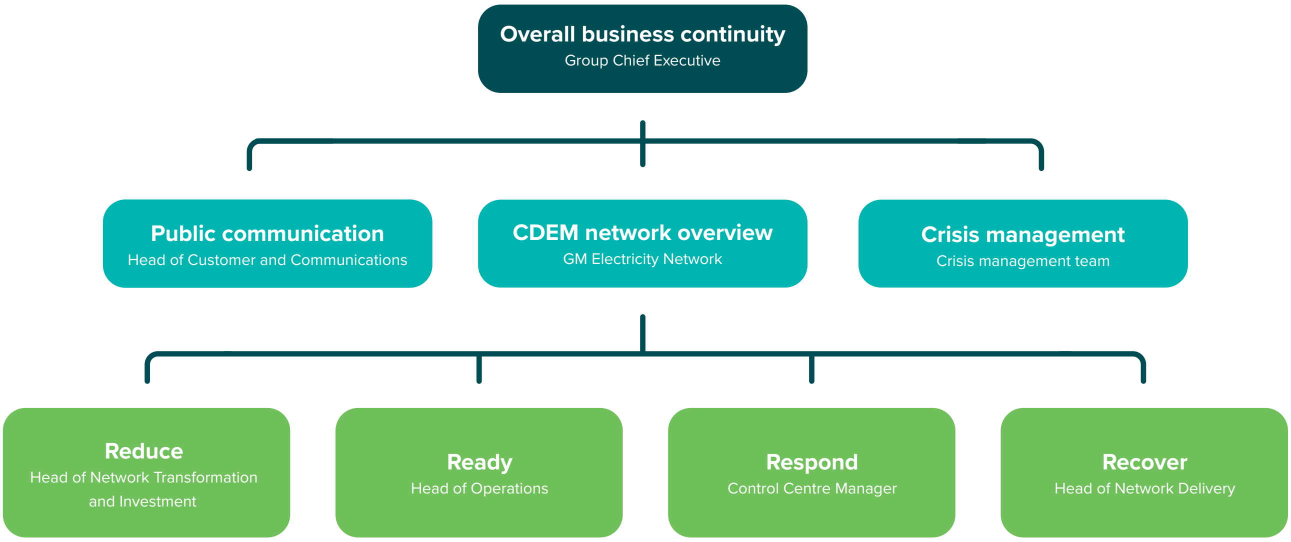
- **Enterprise Risk Lead** – manages our risk framework, policies and practices
- **Head of Sustainability and Risk** – coordinates our ERM management and governance
- **Company Secretary** – coordinates governance processes and our insurance programme
- **Health and Safety team** – helps our line management to continuously improve our processes in these areas

The board audit risk committee also oversees an active assurance programme, that is facilitated by an independent chartered accounting firm.

The Civil Defence Emergency Management Act 2002 (CDEM) requires us to:

- function during and after an emergency, and have plans to support this
- participate in CDEM planning at national and regional level if requested
- provide technical advice on CDEM issues where required
- align our business continuity responsibilities using Civil Defence's 4Rs approach to resilience planning – reduce, ready, respond and recover

Figure 5.6.1 Our HILP and crisis risk management responsibilities



5.6.2 Our HILP / crisis risk management

High Impact Low Probability (HILP) events such as natural disasters, pandemics, or cyber-attacks necessitate situation specific reporting and responsibility structures. Each HILP event is different, so we expect to plan-to-plan following such events.

- **Reduce** – means we implement measures in advance so that the impacts of future HILP events will be less. For example, we have invested in increased IT controls against malicious cyber-attack.
- **Ready** – means we have the people, resources, and procedures in place or available to respond to a future event. A good example of this is that we smooth our planned network opex and capex over time so our service providers can develop and maintain locally sourced capability that may be redeployed to respond when HILP events occur.

  We also have formal and informal mutual aid agreements with EDBs around the Aotearoa New Zealand to provide additional support in HILP events if needed. To respond to large scale events, we have appropriate stock levels of repair items such as replacement poles in strategically placed depots around our region. Addressing the foreseeable risk of a major event means that when it happens, we can respond efficiently using our systems, resources and recovery processes, and power will be restored as quickly as possible.
- **Respond** – means we deal with the immediate and short-term impacts of HILP events. We first seek to understand what occurred and the main impacts, and we then plan, prioritise, and implement measures to ensure a response that has the greatest benefit for the greatest number of customers in the shortest practicable time – this approach is what we refer to as a plan-to-plan.
- **Recover** – means we deal with the medium to long term impact of HILP events. We prioritise and plan our major works to restore our network condition and capability over an appropriate period. Our recover phase can also involve prudent upgrades to parts of our network, given our new risk learnings and new context from the HILP event.

5.7 Our risk assessments and risk evaluations

5.7.1 Our risk assessments

We assess the potential consequences and the likelihood of those potential consequences for our different types of risk areas, such as:

- HILP events
- health and safety
- pandemics
- business continuity and resilience
- people and competence
- supply chain and procurement
- project management
- environment
- climate change
- sustainability
- financial
- strategic
- network capacity and reliability
- IT systems – including cyber security
- Legislation and regulation
- reputation

We assess our risks in a consistent way and have high-level guidelines to inform our judgements.

We assess our risks in consistent way and have high-level guidelines to inform our judgements. These are guidelines rather than rules because unique contexts can affect any situation.

When appropriate, we engage independent experts to help us assess and evaluate our risks and risk controls.

Our risk guidelines have heatmap scores for our risk assessments. These rank risks from 1 to 25 as shown in Table 5.5.1.

Table 5.7.1 Our risk assessment guidelines

Likelihood		Consequence				
		Minor	**Moderate**	**Serious**	**Major**	**Severe**
Almost certain	95% to 100%	6	13	18	23	25
Likely	65% to 94%	5	9	15	21	24
Possible	35% to 64%	3	8	14	19	22
Unlikely	6% to 34%	2	7	11	16	20
Rare	0% to 5%	1	4	10	12	17

Risk rating key:	Low	Medium	High	Very high	Extreme

Our **likelihood rating** guidelines also inform our judgement. Likelihood takes into consideration the external and industry context as well as the history of occurrence. When considering likelihood, we consider relevant issues such as:

- how often a task is carried out, or how often a situation might occur
- how and when the consequence might occur and to whom
- relevant evidence and history
- new factors that might make history less relevant

Our **consequence rating** guidelines inform our judgements. We recognise there could be several different credible consequences that need to be considered for any event or risk source – for example, safety, financial and reputation.

We consider credible consequences that could occur and their potential severity:

- our consequence ratings aim to reflect credible scenarios, given our context and risk treatments
- our likelihood ratings reflect those credible scenarios, including residual risk that remains after implementation of our risk treatments and controls

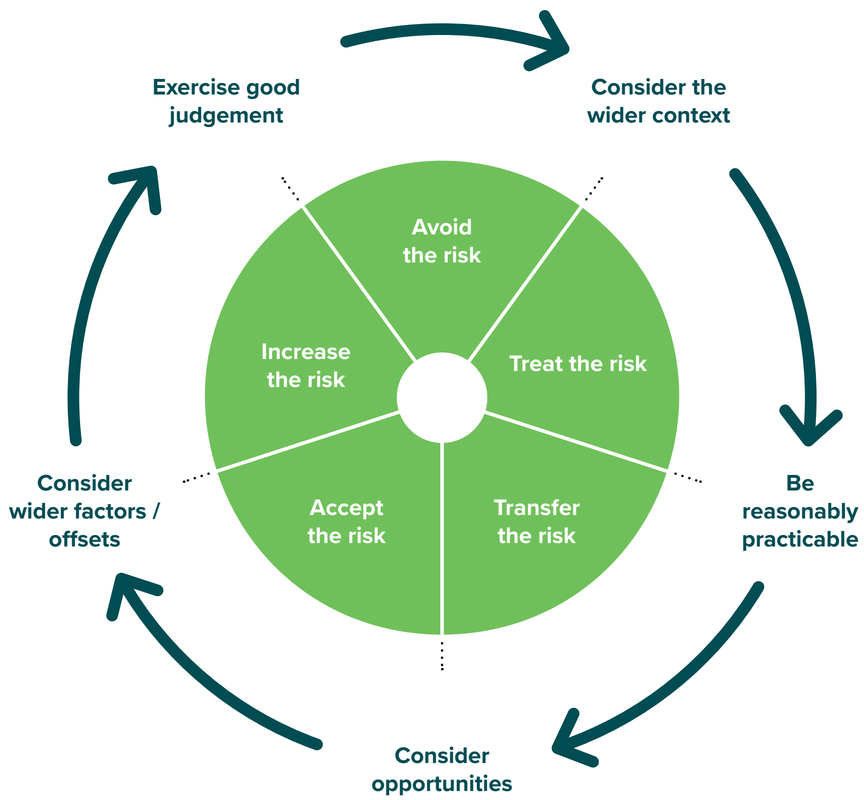
5.7 Our risk assessments and risk evaluations continued

5.7.2 Our risk evaluations

When we evaluate our risks, we decide what to do about them, if anything. We summarise our five major options for action or otherwise, and our framework for deciding which option to take, as shown in Figure 5.7.1. As an extra step, we consider our wider context, using good experience, knowledge and judgement. We ask:

Given our wider context, can we live with our risk assessment rating for this risk, or do we need to change it by way of risk treatment or transfer?

Figure 5.7.1 Our five main risk evaluation options



As a general principle, the higher the risk the more decisively we act. Our overall action and escalation guideline is shown in Table 5.7.2.

Table 5.7.2 Our risk treatment and escalation guidelines

Risk ratings	How to respond	When to escalate	Who to
Low	Accept risk, manage as per normal procedures	Annual, and as appropriate	People leader
Medium	Consider treating risk if reasonably practicable	Annual, and as appropriate	People leader
High	Treat risk if reasonably practicable	Quarterly, and as appropriate	People leader / Integrated Leadership Team
Very high	Take timely action to treat risk	Monthly, and as appropriate	Integrated Leadership Team / board
Extreme	Take immediate and decisive action to treat risk	Immediate, and as appropriate	Integrated Leadership Team / board

5.8 Our key operational risks

Our overall assessments for our key operational risks are shown in Table 5.8.2.

The ratings in Table 5.8.2 are as at 5 August 2023, and are regularly reviewed.

Table 5.8.2 Our overall operational key risk assessments

Likelihood		Impact				
		Minor	Moderate	Serious	Major	Severe
Almost certain	95% to 100%			3, 4, 5		
Likely	65% to 94%			6		
Possible	35% to 64%		10	7, 8, 9		1
Unlikely	6% to 34%					
Rare	0% to 5%					2

1. Major earthquake or tsunami
2. Health or safety incident
3. Severe weather event
4. Physical impacts of climate change
5. Business capacity to adapt to change amid sector transformation
6. Sector cost escalation
7. Pandemics
8. Cyber security breach
9. Inability to achieve organisational cultural change
10. General inflation and interest response

In the following pages we detail our key operational risks along with the main mitigation and controls we use to manage them.

5.8.1 Major earthquake or tsunami

The Canterbury and Kaikoura earthquakes of 2010, 2011 and 2016 indicate that our region's greatest natural disaster risk is a major earthquake. A future major earthquake could be caused by the Alpine Fault or by other known or unknown faults.

A Te Herenga Waka–Victoria University of Wellington study indicates a 75% chance of a major Alpine Fault earthquake in the next 50 years. The study also indicates an 82% chance of the earthquake being magnitude 8 or higher. We have assessed the risk of an Alpine Fault earthquake as severe and the likelihood as possible. We have reviewed our crisis management processes and business continuity plans to ensure that we are prepared for this increased likelihood.

An Alpine Fault earthquake would be centred further away from our urban network and would not be as sharp as the 22 February 2011 earthquake, but it would have a far longer duration, perhaps some minutes. This would test the resilience of our network in different ways to 2011. Our network extends into the Arthurs Pass region, close to the fault line, and while designed and built to the same rigid standards of our flat geographical areas, the earthquake effects are likely to be greater and for longer in this area.

We are vigilant in identifying and assessing risks, and continually improving our processes and outcomes.

A major Alpine Fault earthquake may result in a major outage to significant parts of our network – and the impacts on our community would be more severe if it occurs in winter.

Fortunately, we were well-prepared for the Canterbury earthquakes in 2010 and 2011. We also completed our earthquake recovery projects in FY18, and as part of those initiatives we further enhanced our earthquake resilience.

Our current major resilience project is replacing the remaining 40km of oil filled 66kV cables in Orion's Christchurch urban network over ten years or so. These cables are old technology and the skills to maintain and repair them if they become damaged are increasingly rare internationally and locally. See Section 8.4.1.1 for our resilience programme.

A major future earthquake will also have significant impacts on the ability of some of our team members to contribute to our response and recovery initiatives. We treat this risk in practicable ways – including via:

- well documented policies and procedures
- competent employees and service providers who can and do perform cross-over duties
- policies and practices that aim to support employee well-being
- flexible IT and communication systems that enable our people to work remotely for extended periods of time
- a policy and practice to plan-to-plan and adapt following a major event as necessary
- crisis management processes including simulation events

In summary, we have implemented and continue to implement practical steps to address our earthquake risk exposures

5.8.2 Health or safety incident

Ensuring our people can work safely and our community can go about its daily life in a safe, healthy and sustainable environment is not simply a matter of compliance – it is embedded in our culture.

We continue to strengthen our quality, health and safety focus. We are vigilant in identifying and assessing risks, and continually improving our processes and outcomes.

We aim to actively identify, assess and manage the critical risks typically associated with operating an electricity distribution network by:

- maintaining well-developed and documented policies and procedures
- engaging with trained and competent field workers who can work in complex and dynamic environments
- working with our service providers to encourage safer practices when working around Orion infrastructure
- utilising remotely operated devices to monitor and operate aspects of our network
- taking a collaborative, learnings-based focus for all safety incident and investigations
- continuously improving our risk management and reporting
- conducting public safety education campaigns
- applying quality assurance oversight to provide a better overview of interrelated factors

We have dedicated teams of people to help us maintain a focus on the health, safety and wellbeing of our people, our service providers, and our community.

Our Health and Safety and our Public and Asset Safety Committees have employee representatives from across Orion who meet regularly to review incidents, identify opportunities for improvement in work practices and the work environment, and assist in the education of our people.

We recruit, train, and equip our team members appropriately for their roles. We understand our people are faced with challenging decisions each day – therefore we support them with a wellbeing programme aimed at ensuring our team members are fit to be at work and safely carry out their duties.

We actively consider potential health and safety risks when we design and construct new network components, through our documented Safety in Design process.

We collaborate with our neighbouring and national networks, and industry associations such as the EEA and the ENA, to share knowledge and help us understand our industry risks and what is considered 'good industry practice' management of those risks.

Much of the field work on our network is carried out by approved network service providers. We require our network service providers to have an equivalent health and safety management system to our own. We ensure our network service providers conform to our requirements through our formal contract management process and our auditing programme.

As with all electricity distributors, the Electricity (Safety) Regulations 2010 require us to have an audited public safety management system, with the aim to promote public health and safety, and the prevention of damage to property around the supply and use of electricity. To demonstrate we conform with this requirement, we are independently audited at regular intervals against NZS7901 Electricity and Gas Industries – Safety Management Systems for Public Safety and have been assessed as meeting the requirements.

A major Alpine Fault earthquake may result in a major outage to significant parts of our network – and the impacts of that on our community would be more severe if it occurs in winter.

5.8 Our key operational risks continued

To protect our community from potential harm associated with our infrastructure, we have documented policies and procedures, and create physical barriers which restrict access to our electrical network infrastructure. We:

- prevent access to restricted areas by the public and unauthorised personnel
- prevent inadvertent access to areas by authorised personnel
- prevent entry by opportunist intruders without specialised tools
- slow or impede determined intruders
- ensure ground mounted infrastructure in public areas such as kiosks and distribution boxes are designed to be safe to touch

Electricity is hazardous and regardless of our extensive programme of prudent, proactive measures our risk rating for health and safety is high. At all times, there is credible potential for a member of our team, a service provider or person in our community to suffer a serious injury or a tragic fatality.

This compels us to have effective quality, health and safety performance and continual vigilance by every team member.

5.8.3 Severe weather event

Severe storms can and do result in outages to significant numbers of our customers of up to one hour in urban areas and up to three days in rural areas. Longer outages can especially affect customers in remote rural areas where access may be difficult and snow depth may be more severe. We have continuously improved our network practices in light of past storms in our region – including significant wind storms in 2013 and 2021 – particularly for rural areas in our service region. We have implemented these improvements over time as part of our ongoing network asset lifecycle process and we have implemented strengthened asset loading standards for new network components. Examples of such changes for our rural service area include revised pole spans, revised pole and crossarm types – as appropriate for credible wind and/or snow loadings. Our credible snow loading forecasts recognise that local snow is relatively wet and heavy, in contrast to snow that falls in the middle of large continents.

An important element for this risk category is that the vast majority of the damage to our network in severe storms is due to tree branches, and even whole trees, coming into contact with our overhead lines – especially in rural areas. For more information on how we plan to improve our overhead network resilience see Section 7.5 and our vegetation management programme in Section 7.7.

5.8.4 Physical impacts of climate change

The physical impacts of climate change pose a significant risk to Orion's infrastructure and operations. These risks have the potential to impact our ability to provide a reliable service, increase maintenance and repair costs, and may result in regulatory penalties.

Climate change means our network's region, Central Canterbury, is likely to experience an increasing number of hot days, more severe droughts and increased mean temperatures. Warmer summers may change traditional energy consumption patterns and we can expect the number of extreme weather events to increase. Sea level rise will affect our coastal communities and the assets that serve them. Like most businesses, over the past two years we've learned to be more flexible and agile in how we operate to keep the power on during challenging times.

Orion is ready to play our part for our community in the transition to a low carbon, climate resilient economy. In our Climate Statement to 31 March 2023, available on our website, we share a snapshot of some of the challenges and opportunities we believe are involved in that transition.

We have instigated a range of measures to prepare for the impact of climate change and mitigate the associated risks, both physical and transitional, to our network infrastructure and operations. These include:

- teaming up with NIWA to model the potential impact of four warming scenarios on our overhead network
- exploring the potential impact of electric vehicle uptake and electrification of process heat on our network
- upgrading and developing new systems and processes through significant investment to lift our asset management platforms and customer management tools to state of the art levels
- initiating a step change in Orion's use of data and digitisation to deliver greater operational efficiency and better outcomes for our customers, see Section 4
- planning a range of network maintenance and development projects to increase the resilience of our network, see Sections 7 and 8
- adjusting our climate reporting to cover three short, medium and long term time frames
- qualitatively exploring business impact in our climate risk assessments
- refreshing our Orion Group Strategy to ensure we are 'match fit' to support our community through the climate transition

5.8.5 Business capacity to adapt to change amid industry transformation

The transformation in the energy sector requires EDBs to adapt the way they undertake our operations in a range of ways. These will encompass process redesign, embracing automation, digital transformation, service development, and responding to shifting customer demands at various levels and from different perspectives. Orion's Data and Digitisation strategy, see Section 4, and our Network Transformation Roadmap, see Section 6, are instigating wide ranging changes to enhance and adapt our operations to serve our customers in a transformed energy future.

5.8.6 Sector cost escalation

Within our sector there is significant risk that annual material and salary cost escalation will be persistently above general economy wide inflation in the decades ahead as increased electrification occurs due to decarbonisation efforts. The implications of cost escalation include strained financial resources, reduced operational efficiency, and compromised ability to invest in essential network upgrades and improvements.

To mitigate this risk, we are improving our ability to estimate cost increases beyond the use of forecasts for general inflation measures, such as the Producers Price Index, and we are having detailed discussions with suppliers over future work programmes. For more information on how we are managing this risk in our cost forecasts, see Section 2.

There is an emerging risk associated with theft from our network that adds to our ongoing maintenance and repair costs.

5.8.7 Pandemics

As an essential service provider Orion is acutely conscious of our responsibility to maintain vital power services to our community throughout pandemics.

Healthy and well people are critical to Orion's ability to operate, manage and maintain the electricity network safely. There is therefore a need to limit any spread of illness through our workforce. To be deployed as needed, we have instigated significant measures to ensure the safety and wellbeing of our employees, particularly those who worked in critical control centre and customer support roles, as well as our operators in the field.

We continue to monitor for any developments of this risk closely, and are prepared to adapt to an evolving situation. We believe our recent experience provides Orion with valuable learnings for any future widespread disruptions of this nature.

5.8.8 Cyber security breach

Businesses today face increased risk of cyber security events. Such breaches in cyber security could result in widespread outages, affecting the daily lives and operations of our customers. Businesses may experience downtime, leading to financial losses, while residential customers may face inconvenience and potential safety hazards due to disruptions in their power supply. We have two key categories of risk:

- catastrophic failure of our systems, for any reason
- malicious third-party attack, and compromise, of our systems

We reduce the likelihood and potential impact of these events through a combination of controls, procedures and technologies, including:

- robust systems procurement and maintenance processes
- rigorous change management
- good practice system and data protection and back up
- communication firewalls configured at zone substations and we have installed a centralised security system which logs and controls access to the network
- utilising highly resilient facilities and high system availability
- robust cyber and physical security controls
- active monitoring and alerting of systems
- employing active cyber security services including:
  - 24 x 7 Security Operations Centre (SOC)
  - Managed Detection and Response (MDR) and threat hunting
  - Internal and External vulnerability Managed System (VMS)
  - Endpoint Detection and Response (EDR)
- an active cyber assurance programme, including active security testing

Customers benefit from safe online services, rigorous protection of their personal information and high integrity of our asset information and asset management systems.

To prevent and reduce the potential impacts of attacks by malicious third parties, we employ layers of cyber security controls, active monitoring, ongoing assessment and run a cyber security assurance programme for validation of controls. We employ fit-for-purpose and up-to-date security systems that track and respond to suspicious patterns of behaviour, known digital signatures and actively monitor security events and risks.

We run an ongoing cyber awareness programme, regularly updating and training our people on cyber security, and we seek their vigilant and active support for a secure information systems environment.

We also use the knowledge and experience of others by consulting with our peers in the industry, Government agencies and independent experts. The latter group helps us to build our capacity and also audit our systems and practices so that we continuously improve our resilience to cyber threats.

High international demand for network equipment due to global decarbonisation and geopolitical unrest is exacerbating supply chain risk.

The ever-evolving external environment demands an organisation culture that is responsive, innovative, and capable of swiftly adapting to emerging challenges and opportunities

5.8.9 Inability to achieve organisational cultural change

We acknowledge the crucial role of organisational cultural change in supporting the implementation of our Orion Group Strategy. Failure to effectively deliver this necessary cultural change poses a significant risk to the achievement of strategic objectives. The ever-evolving external environment demands an organisation culture that is responsive, innovative, and capable of swiftly adapting to emerging challenges and opportunities. Without deliberate focus on shaping the cultural fabric of our organisation, there is a risk that we may struggle to align our operations and practices with the evolving requirements of the group strategy. This misalignment could lead to inefficiencies and hindered growth.

To mitigate the risk of failing to deliver the necessary organisational culture change, we are taking a multi-faceted approach, that includes:

- numerous programs have been designed to integrate readiness into various aspects of our business operations
- a dedicated team to focus on the development of comprehensive training materials and modules that aid in communicating the desired cultural changes effectively, facilitation of new practices and behaviours required to align with our group strategy
- quarterly leadership reviews to focus on emerging practices, future insights, emerging trends, and issues relevant to our industry
- engagement surveys conducted across our organisation to gauge employee sentiment, identify potential areas of concern, and gather valuable feedback

In the face of a changing external environment, we recognise the significance of fostering a culture that supports our strategy, we are committed to ensuring that our organisation remains agile, adaptable, and aligned with emerging trends and challenges.

5.8.10 General inflation and interest response

The Commerce Commission historically allows 2% cost inflation in its revenue and cost modelling when setting prices for the relevant five-year control period. Where inflation is above the Commission's estimate, all other things being equal, our capex and opex will be above our expenditure allowances. This imposes Incremental Rolling Incentive Scheme (IRIS) penalties in the subsequent five-year control period. The actual capex forms part of our regulatory asset base at the next price reset so is recovered in our prices from that time forward.

The Commission's revenue allowance calculation allows us to recover actual inflation when we set our prices – however, there is a two-year lag between the actual period of high inflation and the period in which we can recover the amount in cash. That is, high inflation in the year to 31 March 2024 will be recovered in prices set to apply from 1 April 2025 onwards. In periods of high inflation this delay leads to the deferral of revenue to later years.

These cost and revenue factors lead to considerable volatility in profit during and after periods of high inflation.

Orion can mitigate interest rate risk by entering interest rate swap agreements to effectively "fix" interest rates for the majority of our actual and forecast borrowings for the relevant five-year control period. We enter such swaps at the same time as the Commission sets regulatory returns for the five-year control period.

5.9 Summary of our top 10 risks and mitigation strategies

Top 10 risks	What we are doing to mitigate it
Major earthquake • Could also trigger a tsunami	• Earthquake strengthened substations • Investments in earthquake resilience • Replacement of oil filled cables
Serious health or safety incident • Affecting our people, service providers and / or the public	• Well-developed policies and procedures • More remotely operated devices • Collaborative, learnings-based incident investigations • Public safety education campaigns
Severe weather event • Resulting in significant power outages and business disruption	• Strengthened asset loading standards • Revised pole spans, revised pole and crossarm types • Enhanced vegetation management programme
Climate change • Impacts on equipment, vegetation management and increase in severe weather events	• Asset maintenance and network development projects to increase the resilience of our network, see Sections 7 and 8 • For more detail, see our Climate Statement, on our website
Business capacity to change amid sector transformation • Implementing new operational processes to enhance performance	• Instigating wide ranging changes to enhance and adapt our operations to serve our customers in a transformed energy future • Initiating a step change in Orion's use of data and digitisation see Section 4.5 • Our Network Transformation Roadmap, see Section 6.6.1
Sector cost escalation • Greater than forecast	• Improving our ability to estimate cost increases • Detailed discussions with suppliers over future work programmes • Managing this risk in our cost forecasts, see Section 2
Pandemics • Supply change issues; lack of skilled workforce availability	• Pandemic Response Plan in place • Separated teams for critical operational roles • Equipped essential workers with equipment to enable working from home
Cyber security breach • Catastrophic failure of our systems or malicious third-party attack	• Robust cyber and physical security controls • Employ cyber security services • Active cyber assurance programme, including active security testing
Inability to achieve organisational culture change • Important to achieve our Orion Group Strategy	• Multi-faceted approach to organisational development, see Section 4.2
General inflation and interest rate rises • Greater than that provisioned for	• Entering interest rate swap agreements to effectively "fix" interest rates for the majority of our actual and forecast borrowings for the relevant five-year control period

5.10 Our resilience to business interruption

At Orion, building resilience into our network is a priority – reinforced regularly by customers in their conversations with us. Our approach to resilience also encompasses ensuring the resilience of our organisation's capacity to continue to function and maintaining vital services to the people and businesses of Central Canterbury.

We define resilience as our capacity to endure, adapt to and rebound from substantial events, particularly High Impact, Low Probability (HILP) events. Orion's capacity for resilience is the bedrock of our ability to deliver a safe, reliable, sustainable and functioning service, ensuring the enduring welfare of the communities we serve, come what may.

Figure 5.10.1 Orion's multifaceted approach to resilience

5.10.1 Community resilience

Community resilience is about fostering an empowered and prepared community which can navigate disruptions and bounce back stronger. Orion plays an essential role in this by:

- **Education and engagement** – we proactively engage with the community to raise awareness about electricity safety, energy efficiency, and preparedness during power outages. We run a comprehensive advertising programme covering tree trimming, DIY safety, and farm safety around power lines. We have also added our 'Dial it in' campaign in response to ongoing tampering with our network. The Snap Send Solve app also provides an accessible way for our community to report something out of place on our network.
- **Collaboration** – partnering with local government, businesses, and non-profits allows us to integrate our services seamlessly, ensuring that the community receives timely support during emergencies. We work with the NZ Lifelines council, other utilities and local councils to align on the four Rs of resilience: Robustness, Redundancy, Rapidity and Resourcefulness.
- **Adaptability** – our initiatives, such as supporting community-based renewable energy projects or energy education, empower individuals to be energy resilient and self-sufficient. We have information on our website about being prepared for a power outage and how to cope.

  Our Customer Support team provides regular, updated messaging during outages, to keeps people informed. Our opt-in outage notification service also allows our customers to be notified about planned outages, giving them the ability to better prepare.

5.10.2 Infrastructure resilience

We are committed to ensuring our infrastructure and systems can withstand, recover, and adapt to various challenges, be they natural disasters, technological disruptions, or evolving energy demands. We support this commitment by having:

- **Advanced systems** – implementing state-of-the-art systems that monitor, predict, and swiftly respond to any anomalies or disruptions. In 2023, we installed an Adaptive Power Restoration System (APRS) to our Advanced Distribution Management System (ADMS). This allows us to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply.
- **Continuous upgrades** – regularly updating our infrastructure to adhere to the best international standards, ensuring longevity and reduced vulnerability. We are actively analysing our network to identify areas where we may need to upgrade assets as a part of our focus on climate adaptation, particularly our older overhead network.

- **Sustainable design** – embracing designs that are environmentally sound and can adapt to changing climatic conditions. We are currently looking at an alternative pole material type with a view to mitigating hardwood supply chain risk and carbon sequestration.

5.10.3 Organisational resilience

Orion's strength lies in its people and its organisational culture. Ensuring our team is adaptable, skilled, and prepared for any unforeseen challenges is a priority. Organisational resilience is ingrained through:

- **Training and development** – continuous training programmes ensure our team is equipped with the latest knowledge and skills. For more information see Section 4.2.
- **Stakeholder engagement** – regular feedback loops with our stakeholders, including the community, partners, and regulators keep us grounded and aware of the broader ecosystem's needs and expectations. See examples in Sections 2 and 3.

5.10.4 Emergency response and contingency plans

Orion is committed to capability building and readiness for emergencies and disasters following significant natural hazard events. Resilience is primary investment driver for our network development and asset lifecycle management. Supporting this investment in the resilience of our network, we undertake extensive emergency planning, conduct simulated emergency practice exercises, and have put in place significant back-up provisions for our key operational functions.

5.10.4.1 Emergency planning

Orion is transitioning to the Coordinated Incident Management System (CIMS) model for both emergency and crisis level events across all event types. Using New Zealand's official emergency management framework will bring our emergency response into alignment with that of other utilities and emergency services, enabling us to achieve more effective, co-ordinated incident management.

To build capability at Incident Management Team (IMT) level, we have rolled out CIMS training to 60 team members across Orion, including those in our Integrated Leadership Team. Alongside this capability development we have also reviewed and updated our emergency management documentation to ensure the CIMS model is at the core of all Orion emergency and crisis management documents.

Orion has all the key components of effective emergency and crisis response in place. Our emergency response team structures, roles and terminology have now been brought into line with the CIMS model. Where appropriate, information and tools from Orion's previous crisis management system have been retained.

Orion has also learned much from its past emergency experiences and can tap into the extensive knowledge of our team members on what works and what's needed in a range of crisis situations.

5.10.4.2 Simulation exercises

In FY23, the Orion team carried out a CIMS training exercise to test our coordinated response in the event of a disaster following a catastrophic natural hazard event.

"Exercise New Moon" put our people and systems to the test with a simulated Alpine Fault Magnitude 8 (AF8) scenario – one of Orion's top 10 risks.

An Emergency Operations Centre was established at Connetics' office and the exercise wrapped up with a hot debrief to share lessons and insights, led by an Exercise Controller from PlanitSafe. As a result of the lessons learned, Orion is reviewing our resilience measures, building further emergency management capability within our teams, planning for all types of significant events and testing these plans at least annually.

Orion also participates in Electricity Authority and Transpower industry simulation exercises of a major power system event. These exercises have two major components:

- operational processes and interactions between the system operator and distributors – for control room operators
- communications and interactions between Transpower, distributors and retailers – for digital communications/ social media/customer leads

In these events, Orion's role in coordinating Upper South Island load management means we work closely with other regional EDB colleagues and industry leaders as part of a national response.

5.10.4.3 Operational contingencies

As a lifelines utility under the Civil Defence Emergency Management Act 2002, we are required to be operational after a significant event. Our administration building, which houses our Network Control Centre, was built to Importance Level 4 (IL4). This means the building is designed to remain operational following a 1 in 500-year seismic event. Our main administration building is also equipped with a standby generator, with 5000 litre diesel tank, for back-up power.

As part of our Pandemic Response Plan, we established a permanent emergency operations centre for our Network Controllers and Customer Support team at our Papanui zone substation. This alternative site provides back-up if needed, and the option for separating our key personnel in the event of a pandemic.

In addition, we have established alternative offices in Ferrymead and Rolleston, and set up our key employees with equipment to enable to them to work from home.

At our subsidiary Connetics' depot and our Papanui Emergency Operations Centre, we have emergency supplies of vital, core equipment such as power poles, cable, switchgear, protection equipment, transformers and 3.5MVA of transportable diesel generation. Connetics and our other service providers have emergency works requirements included in their contracts.

5.10.5 Resilience Management Maturity Assessment Tool (RMMAT)

In November 2020, the Electricity Engineers Association (EEA) released an Industry Resilience Guide with the objective of equipping Electricity Distribution Businesses (EDBs) with tools to enhance their resilience to extreme events that could jeopardise their capacity to deliver electricity to consumers.

Figure 5.10.2 RMMAT maturity levels

Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
The organisation has not recognised the need for this requirement, and / or there is no evidence of a commitment to put it in place.	The organisation has identified the need for this requirement and there is evidence of an intent to progress it.	The organisation has identified the means of systematically and consistently achieving the requirement and can demonstrate that progress is being made with credible, and resourced plans in place.	The organisation can demonstrate that it systematically and consistently achieves relevant requirement. Only minor inconsistencies may exist.	The organisation can demonstrate that it consistently exceeds the requirement. It employs and fosters leading local and international industry practices and has a mature continuous improvement culture to ensure a high standard of maturity and compliance is maintained.
Not aware	**Aware**	**Developing**	**Competent**	**Excellent**

Figure 5.10.3 Orion's RMMAT scores

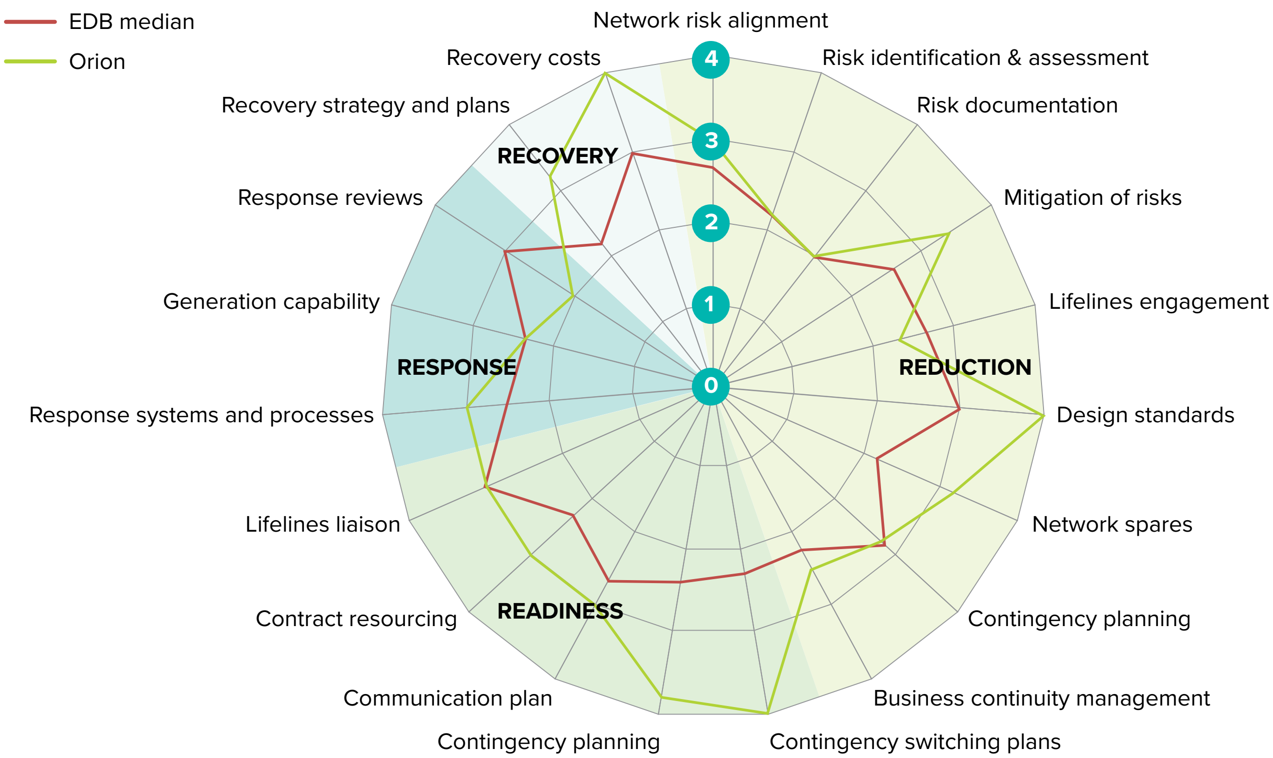


Table 5.10.1 Orion RMMAT score vs EDB sector average		
Phase	**Orion average score**	**EBD sector average score**
Reduction	2.9	2.5
Readiness	3.2	2.5
Response	2.4	2.6
Recovery	3.6	2.6
Total	3.01	2.55

A series of evaluative questions form the basis of the Resilience Management Maturity Assessment Tool (RMMAT). The purpose of the RMMAT is to allow organisations to determine their level of resilience maturity and identify areas where improvements could be made. The expectation is that the RMMAT will reveal improvement opportunities, and addressing these could bolster network resilience within the organisation. To continually improve our reliability and resilience in the face of extreme events, Orion completed the RMMAT assessment for the first time in 2023.

Orion's RMMAT scores suggest a positive starting point on our journey towards a more resilient electricity network, see Figure 5.10.3 and Table 5.10.1. The assessment breaks down resilience into four categories: Reduction, Readiness, Response, and Recovery. In each category, the scores can range from 1 (Not Aware) to 5 (Excellent), with our scores ranging from 2.4 to 3.6.

5.10.5.1 Reduction

In the Reduction category, which assesses our ability to minimise the potential for disruptions, we achieved a score of 2.9. This suggests we are in the 'Developing' stage, indicating we have identified systematic methods to reduce risks and are making demonstrable progress, with resourced plans in place.

5.10.5.2 Readiness

Our Readiness score of 3.2 indicates that we are approaching the 'Competent' level. This means that Orion is well-positioned and has systematic and consistent plans to be ready for potential disruptions, and only minor inconsistencies exist in our approach.

5.10.5.3 Response

In the Response category, which evaluates how well we react when disruptions occur, our score was 2.4. Although we have already taken steps to systematically respond to disruptions, this highlights opportunities for improvement, and we are committed to advancing our strategies in this area.

5.10.5.4 Recovery

Orion's highest score was in the Recovery category, with a strong score of 3.6, nearing the 'Excellent' level. This score is encouraging as it indicates Orion systematically exceeds the required measures for recovery following disruptions, maintaining a high standard of maturity and compliance.

Overall, these results have provided valuable insight into our existing resilience measures and highlight the areas where we can focus our efforts for improvement. We are committed to the improvement of our community, organisational and network resilience.

Through consistent assessment, learning and adjustment, we will continue to raise these scores, enhancing our ability to prevent, prepare for, respond to and recover from potential disruptions. For more on how we are developing organisational and network resilience, see Sections 4, 7 and 8.

We are committed to the improvement of our community, infrastructure and organisational resilience.

5.10 Our resilience to business interruption continued

Our key documents that relate to our network resilience are as follows:

Table 5.10.2 Orion key network resilience documents

Documents	Description
Asset Management Policy Section 2.7	This policy underpins our whole asset management plan and processes. Our policy arises from a good understanding of our context, our purpose and our aim to achieve what is sustainable and in the long-term interests of our customers, our community and our shareholders. Ensuring sustainable and practicable network resilience is an important policy objective for us – and this AMP outlines how we aim to continue to do that.
Asset risk management plan	This plan's topics include: • our key natural disaster risks • our rating system for our key network components most at risk • our main risk controls, and our practical solutions to reduce risk • key locations and the most likely reasons for network asset failure • our main contingency measures • our key network emergency spares
Network disaster resilience summary	An overview of how we plan, design, construct and operate our network, and our supporting infrastructure. Aims to inform Civil Defence and other stakeholders of our overall network resilience in support of wider community major incident planning.
Participant rolling outage plan	Pursuant to the Electricity Industry Participant Code 2010, this plan outlines how we respond to grid emergencies that are declared by the grid System Operator. Typical scenarios include very low hydro lake levels, loss of multiple generating stations, or multiple transmission grid component failures. Our plan outlines how we shed load when requested by the System Operator – the plan is on our website. We help to prevent cascade failure on the transmission grid when we: • help Transpower with its automatic under frequency load shedding (AUFLS) by providing a schedule of our preferred urgent load shedding locations and AUFLS provision where embedded in our network • help Transpower with its automatic under voltage load shedding (AUVLS) for upper South Island transmission constraints by providing a schedule of our preferred urgent load shedding locations and AUVLS provision where embedded in our network • provide 'blocks' of load to Transpower for emergency load shedding We aim to keep supply on for our customers, and load shedding is always a last resort after all other forms of electricity demand savings (including voluntary savings) have been exhausted.
HV Network Security of Supply Standard	This standard, see Table 6.4.3, is key to how we plan to meet customers' demand for electricity in certain circumstances.
Network physical access security plan	This plan outlines our plan to restrict physical access to our electrical network and associated infrastructure, and it supports our commitment to provide a safe, secure and reliable network for our customers and community. Our main focus is to restrict access by unauthorised personnel. Some aspects also affect authorised personnel. We aim to achieve this by: • reasonable measures to prevent access • additional measures to deter, detect and slow determined intruders at higher risk sites
Environmental risk register	This register summarises our key environmental risks.
Climate Statement	Outlines our governance, strategy, and risk management approach and the actions we are taking in response to the impacts of climate-related risks and opportunities, along with metrics and targets. Available on the Orion website.
Business unit continuity plans	Each business unit manager is responsible for their respective plan.
Contingency plans	Failures of primary network assets such as 66/11kV transformers or 66kV cables are rare on our network, but can cause significant outages for many of our customers, depending on the circumstances. To mitigate this risk, we have identified the credible failure scenarios for our primary assets and for each failure scenario we have developed a contingency plan to restore supply in a timeframe consistent with our security of supply standards. In some cases, our contingency plans identify the need to alter our network or hold additional spare assets to meet our objectives. Our contingency plans are held by our network operations team and they are updated regularly.
Communication plans	As part of our emergency preparedness, we have a Crisis Communications Plan, and Communication Plans for projects that involve significant power outages and major outage communication plans. In emergencies, we aim to keep our customers and the community informed, and we work closely with our key stakeholders in emergency management.

6

Our planning approach

Photo: Growth in subdivisions such as this in Halswell is a key driver of projects in this AMP.

Contents

6.1 Introduction

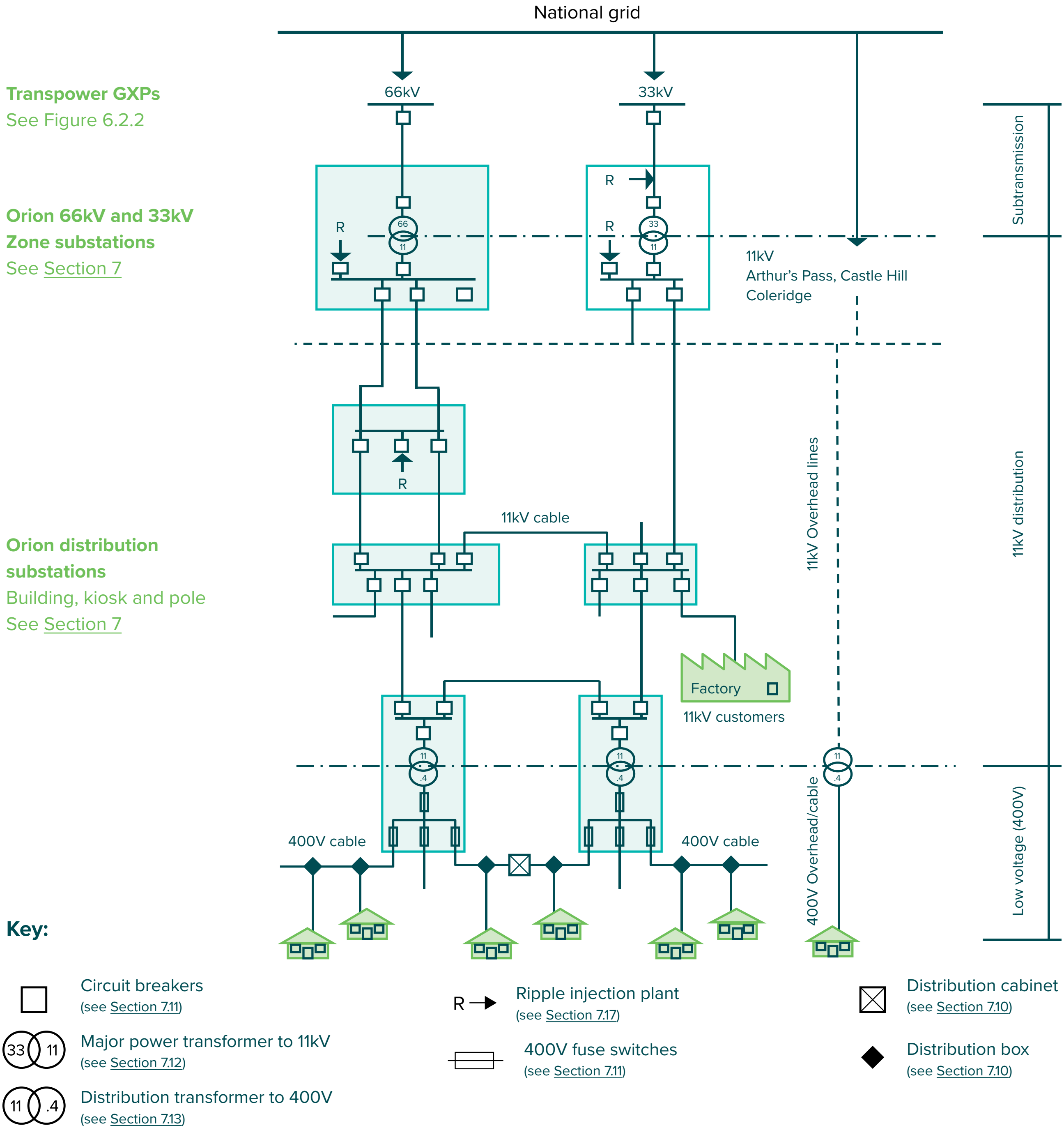
This section provides an overview of our network and how we evaluate different options to address the constraints we are forecasting. The section sets out our processes for prioritising our projects, and how we are transforming our network using non-traditional approaches and innovation to utilise our assets more effectively - shifting from the traditional one-way power flow to a smart network.

6.2 Current network overview

6.2.1 Network architecture

Figure 6.2.1 shows an overview of Orion's network architecture.

Figure 6.2.1 Network voltage level and asset relationships



6.2.2 Transpower Grid Exit Points (GXPs)

Orion's network is supplied with power from eight Transpower Grid Exit Points (GXPs), listed in Table 6.2.1. The remote GXPs at Coleridge, Arthur's Pass and Castle Hill each have a single transformer and a relatively low throughput of energy.

The number of customers joining Orion's network annually has been steadily growing with a record 5,100 new connections in FY23. Many of these new customers are located to the west and south of Christchurch. This is increasing our reliance on the Islington GXP. To support customer growth and ensure the reliability and resilience of our network, in FY22 we commenced work with Transpower to build a new GXP at Norwood, near Dunsandel. The new Norwood GXP was commissioned in December 2023.

We have a number of assets installed at Transpower GXP sites. These assets include subtransmission and 11kV distribution lines and cables as well as communication equipment and protection systems. They are covered by an Access and Occupation Schedule Agreement with Transpower. Orion owns all the subtransmission and distribution assets connected to the GXPs.

The number of customers joining Orion's network annually has been steadily growing with a record 5,100 new connections in FY23.

Transpower charges electricity distributors such as Orion and direct connect customers for the cost of upgrading and maintaining GXPs. We work with Transpower to plan for GXP connection asset upgrades to ensure that any capital expenditure at the GXP is cost effective. Security of supply for our subtransmission network largely depends on how Transpower's assets are configured. We continue to review quality and security of supply gaps.

Table 6.2.1 Customers by Grid Exit Point as at 31 March 2023

GXP	Customer Allocation (% ICP)	Energy Delivered (MWh)
Islington	51%	2,623,790
Bromley	46%	703,004
Norwood	n/a	n/a
Hororata	2%	111,399
Coleridge, Arthur's Pass, Castle Hill and Kimberley	1%	83,119

Orion's network serves a diverse range of more than 220,000 customers, spread over a variety of terrains with different challenges. We own the majority of the network, with only a small embedded network spanning the Rakaia River, owned Electricity Ashburton.

For planning purposes, our network is divided into two regions:

Region A – Christchurch city and outer suburbs, including Prebbleton, approximately 83% of our customers

Region B – Banks Peninsula, Selwyn district and townships, approximately 17% of our customers

Figure 6.2.2 Transpower assets in our region

Region A

Region B

Region A GXPs

As shown in Figure 6.2.2, Region A GXPs are located at Islington and Bromley and supply Christchurch Central City, Lyttelton and the wider Christchurch metropolitan area. Islington and Bromley 220kV substations form part of Transpower's South Island grid. They interconnect between the major 220kV circuits from the southern power stations and our 66kV and 33kV subtransmission network. Islington has a 66kV and 33kV grid connection, while Bromley supplies a 66kV grid connection only.

Region B GXPs

Islington GXP also supplies a large part of the Region B network including Banks Peninsula, milk processing near State Highway 1, irrigation east of State Highway 1, and the Dunsandel, Rolleston and Lincoln townships.

Hororata and Kimberley GXPs supply a significant proportion of inland irrigation load and milk processing. These two GXPs have a connection to the double circuit 66kV line between Islington and the West Coast with generation injection at Coleridge power station. Transpower provides a 66kV connection at Kimberley and a 66KV and 33kV connection at Hororata.

Norwood GXP also supplies this area.

The remainder of Region B is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill.

Together these sites supply less than 1% of our customers and load.

6.2 Current network overview continued

6.2.3 Major customers

Orion has 413 customers who we categorise as major customers. We individually discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade.

If major customers require extra capacity or wish to explore options to better manage their energy consumption, we work with them to meet their needs. This can mean a change to our network supply configuration, on-site generation options or energy saving advice.

Some major customers are looking to decarbonise their process heat load and we are working with them to explore electrification pathways. Section 6.4.1 outlines how this impacts our load forecast.

Our delivery pricing structure for major customers gives them the ability to reduce costs by managing their load during control periods from 1 May to 31 August.

Our major customers operate across a range of industries and sectors see Table 6.2.3.

6.2.4 Embedded distributed generators

Table 6.2.2 lists the generators 1000kW or greater in size that are connected to the Orion network.

Table 6.2.2 Distributed generation 1000kW or greater by GXP

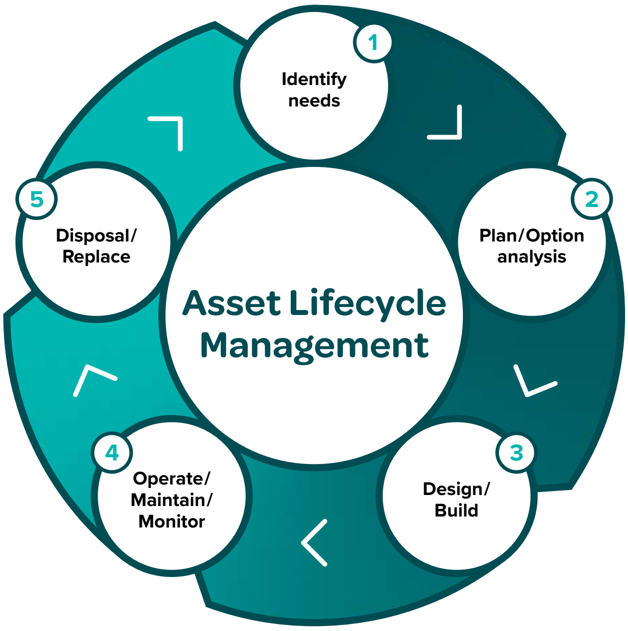
GXP	Capacity (kW)	Voltage	Generator type
Bromley	1,550	11kV	Diesel back-up
Bromley	1,120	11kV	Diesel back-up
Islington 33kV	2,000	11kV	Diesel back-up
Islington 33KV	1,320	11kV	Diesel back-up
Islington 33kV	1,320	11kV	Diesel back-up
Islington 66kV	1,320	11kV	Diesel back-up
Islington 66kV	1,320	11kV	Diesel back-up
Islington 66kV	1,025	11kV	Diesel back-up
Islington 66kV	1,000	11kV	Diesel back-up
Islington 66kV	1,000	11kV	Diesel back-up
Islington 66kV	1,000	11kV	Diesel back-up

Table 6.2.3 Major customers by load size

Load	Industry / Sector	Number	Notes
≤ 2MVA	All	395	Includes heavy manufacturing, hotels, water and wastewater pumping stations, prisons, retail and businesses.
> 2MVA	Food processing	6	
	Hospital	2	
	Shopping mall	2	
	Tertiary education	2	
	Airport / seaport	2	As part of our obligations under the Civil Defence and Emergency Management Act we have on-going discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.
	Manufacturing	2	
	Agriculture	1	
	Sewerage and Drainage Services	1	

6.3 Asset lifecycle investment process

Asset Lifecycle Management describes the strategic approach we take to managing assets throughout their lifecycle, from acquisition or creation to disposal. Our goal is to optimise network performance, minimise costs, and ensure assets serve their intended purpose without presenting unacceptable safety risks. This aligns with our asset management focus area of investing to maintain a safe, reliable, resilient network at lowest lifecycle cost. In this section we detail the five steps in asset lifecycle management.



6.3.1 Identify needs

The first step in the asset lifecycle management process is to establish customer needs and future network demands. This is verified and supported by the various customer engagement and workshops we carry out periodically. This year, we will engage with our Customer Advisory Panel and directly with customers more extensively. Our aim is to engage with them about our expenditure and the proposed level of spending. We will seek their feedback and validation of our investment plans for the next few years. We also consider health and safety and regulatory requirements. With an understanding of what's needed, we set service level targets against which we measure our performance. For details of how our service levels are set, our service level targets and our performance against them, see Section 3.

6.3.2 Planning and options analysis

After identifying needs, we translate them into specific asset management objectives and KPIs as outlined in Section 3.7. These objectives and KPIs can vary across different asset classes. For example, our focus on improving SAIDI and SAIFI concentrates on our overhead assets rather than our substation assets given their exposure to the elements and vulnerability to severe weather events.

In order to achieve our asset management objectives, we review our replacement and maintenance strategies, and assess the appropriateness of our forecasting methods as described in Section 6.3.5. This ensures our strategies remain aligned with the evolving needs of our customers, and the asset's continued effectiveness and relevance.

6.3 Asset lifecycle investment process continued

6.3.3 Design and build

We utilise the project prioritisation process set out in Section 6.5 to determine if the work plan can be delivered. We use service providers for the design, build and maintenance programmes identified in the AMP. To guide them, we have key standards and specifications which are set out in Table 6.3.1 and Appendix D.

Table 6.3.1 Orion standards and specifications

Standard or specification	Purpose
Safety in design standard	Used by Orion and our service providers to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal. The standard includes a hazard identification and risk assessment process which proposes elimination and control measures to be incorporated in the design for each identified hazard.
Design standards	To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where possible. To achieve this standardisation we have developed design standards and drawings that are available to our service providers. Normally we only accept designs that conform to these standards, however this does not limit innovation.
Technical specifications	We provide technical specifications to authorised service providers who work on the construction and maintenance of our network and these refer to the relevant codes of practice and industry standards.
Equipment specifications	We standardise equipment used to construct components of our network where possible. To support this, we have developed specifications that detail accepted performance criteria for significant equipment in our network. New equipment must conform to these specifications. However, without limiting innovation, equipment that differs from specification is considered if it offers significant economic, environmental, and operational advantages.

6.3.4 Operate, maintain and monitor

After the installation of an asset onto the network, it is actively operated and subsequently, it becomes part of our routine inspection and maintenance cycles. This systematic approach ensures the ongoing effectiveness of the assets within the network. For detailed guidelines on the standards employed for operating these assets, see Table 6.3.2 and Appendix D for more detailed information.

Each asset class is subject to a specific regime for routine inspection and maintenance and specified asset replacement programmes. We develop requirements and scopes of work from these plans in-house and use our contract delivery framework to contract out works, see Section 9. Monitoring of assets is against the service levels defined in this AMP, and against specific requirements of the asset class.

Table 6.3.2 Operating standards and procedures

Standard or specification	Purpose
Equipment operating instructions	To ensure equipment on our network is operated safely and with minimum impact on our customers, we have developed operating instructions that cover each different equipment type on our network. This means that we create a new operating instruction each time any new equipment type is introduced.
Operating standards	To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

The detailed asset management activity of each asset class and the equipment within the asset class are described in Section 7 and in our associated internal Asset Management Reports. We have specific maintenance processes for each of our asset classes and all works generally fall into three categories: scheduled, non scheduled and energy maintanence.

Scheduled maintenance

Most of our assets are subjected to a routine time-based programme of inspections, maintenance, and testing. The drivers for time-based maintenance are influenced by regulatory compliance, manufacturer specifications, industry best practice and our engineering knowledge and experience.

We also monitor the condition and performance of our assets through inspections, maintenance, and asset failures. When undesirable performance or high-risk events are identified, we investigate and determine if and what steps are required to bring improve the performance and risk of the asset fleet. This can lead to specific planned and targeted maintenance programmes or if appropriate feed into our renewal programmes.

Non-scheduled maintenance

- Work that must be performed outside the predetermined schedule but does not constitute emergency work.
- Investigative inspections and maintenance that can help determine if a scheduled program of work is needed.
- Follow up remedial work required after emergency maintenance.

Emergency maintenance

- Initial response to unplanned events that impair normal network operation including a loss of supply event.
- Work that must be carried out on a portion of the network that requires immediate repair due to the discovery of an immediate high risk to network supply or public safety.

For details on the forecast growing impact of vegetation on Orion's network, and our management strategy to address this risk, see Section 7.7.

6.3.5 Dispose and replace

We are committed to disposing of our assets in an environmentally responsible and sustainable manner.

6.3.5.1 Disposal

Disposal of assets is also informed by our Asset Management Reports for each asset class and in accordance with replacement and disposal plans. As with maintenance, we develop requirements and scopes of work in-house and then go through a competitive tender process to contract out the works. We are committed to disposing of our assets in an environmentally responsible and sustainable manner that complies with legislation and local authority requirements, and minimises waste.

Our service providers are responsible for the disposal of redundant assets, equipment, hazardous substances and spill wastage, including assets that fail in service, unless we specify otherwise in our contract documentation. Our service providers notify us of disposals and we update our asset information systems to record these. We closely collaborate with our service providers to ensure that the assets are disposed of safely and that hazardous materials are not passed on to any other party without our explicit approval. When we design new assets, our Safety in Design process mandates the identification, risk assessment and control of hazards that could arise during the lifecycle of our assets, inclusive of when we dispose of them. The procedures for the disposal of redundant assets are described in Section 7 under Disposal plan.

Table 6.3.3 Forecasting approaches used for asset lifecycle management

Forecasting approach	Description
Condition Based Risk Management (CBRM) model	Used for high-value, high-volume assets or assets with a high consequence of failure – predominantly condition based replacement based on robust inspection, testing and failure rate. See Section 6.3.5.2 for more information.
Engineering analysis and individual business case	Used for high-value, low-volume assets where it is feasible and efficient to conduct a detailed engineering assessment and analysis e.g. power transformers.
Forecasts based on past failure rates modified where possible by knowledge of age profiles	Used for components where we do not have sufficient information to predict asset health and risk and are instead renewing on an inspect and replace as necessary basis. Examples include pole top hardware such as cross arms and insulators which are not currently recorded as assets in our systems.
Run to non-operational	Used for voluminous assets with an individual low cost and low consequence of failure – run until non-operational, with limited inspections that are focused on identifying damaged assets that represent a safety or environmental risk.

6.3.5.2 Replace

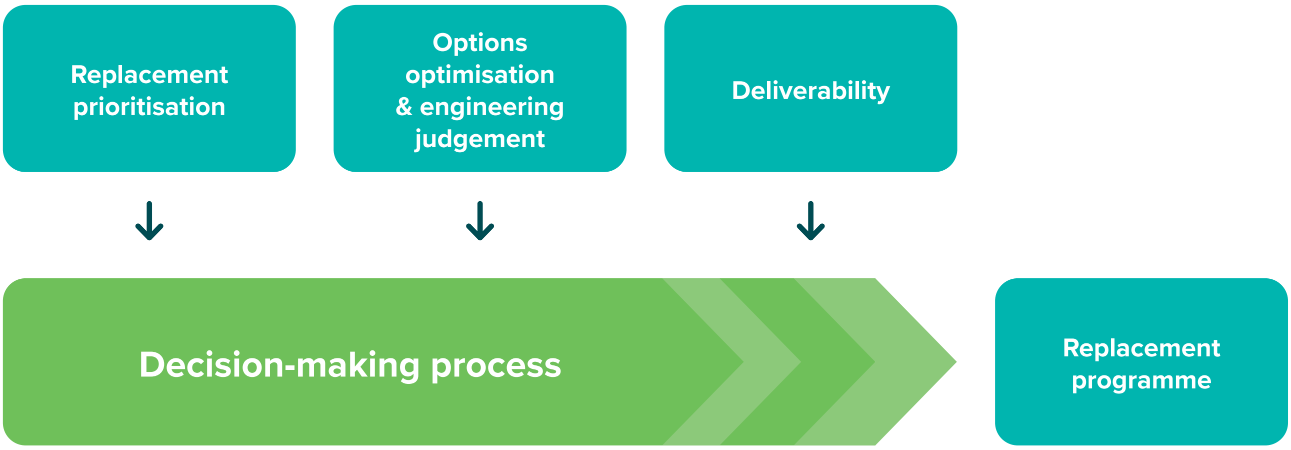
We use a number of techniques to ensure our assets are kept in service until their continued maintenance is uneconomic or they have the potential to pose a health and safety, environmental or reliability risk. This is in line with our asset management objective which is to identify and manage risk in a cost-effective manner and apply a balanced risk versus cost approach to making asset maintenance and renewal decisions. Table 6.3.3 provides a summary of the asset management approach for each asset category.

Once an asset has been identified for replacement via the forecasting approach described in Table 6.3.3, we look at options for the timing of the renewal. This ensures customers are getting the best usage and value out of our existing assets. The CBRM model helps in this process by creating scenarios that model the deterioration of asset condition and projected risk. This information allows us to then decide which scenario is acceptable based on its effect on our service levels.

Another option that factors into our decision-making is whether an asset should be replaced like-for-like. We conduct internal reviews for the asset within various working groups, considering its interaction with other equipment and integration into the immediate network based on the following considerations:

- The required functions, and whether the equipment needs to be replaced or can the function be accommodated elsewhere
- The manufacturer, standardisation of equipment, failure modes, industry experience with certain models, support from manufacturer
- Safety
- Whether the timing can be linked to other work on the substation, network, or circuit to minimise outages and better utilise resources
- Suitability for future change in the network
- Lifecycle cost and environmental impact

Figure 6.3.1 Optioneering process for asset replacement

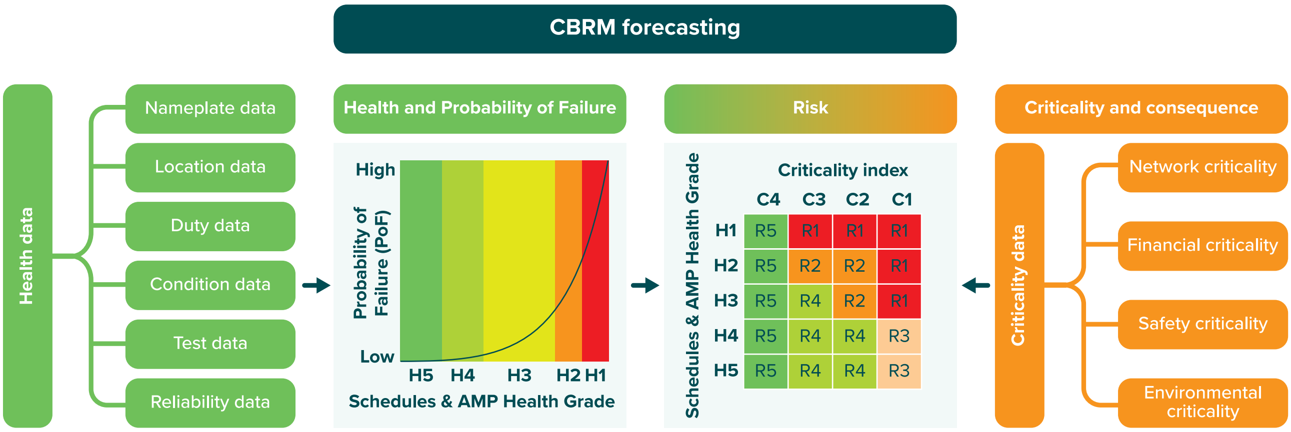


CBRM model overview

The Condition Based Risk Management (CBRM) model is a mature, proven and industry-accepted method for forecasting and scenario analysis of future asset health, asset criticality and risk. We use CBRM for many of our network assets to inform decision-making in our asset renewal programmes. CBRM utilises asset characteristics, condition, the asset's installed environment, operating context, and expert tacit knowledge to model and predict and forecast each asset's current and future probability and consequence of failure and from this risk. For a high-level description of the CBRM methodology, see Figure 6.3.2.

We currently use CBRM for asset classes where we have appropriate input data and where we consider the insight gained by the modelling process will be beneficial. We currently have active CBRM models for power transformers, switchgear, and distribution poles. For a description of our CBRM methodology, see Figure 6.3.2.

Figure 6.3.2 Condition Based Risk Management (CBRM) methodology



Asset health

CBRM quantifies asset health using the asset health index. The asset health index has six sources of input data that combine to provide a reference to each asset's lifecycle stage and probability of failure. The six sources of input data are:

- **Nameplate data** – defines the asset type and age. Each asset type varies in design and manufacture, and based on Orion's operating experience, can be assigned an expected life.
- **Location data** – defines the operating environment, for example, high corrosion vs. low corrosion environment, a factor that can considerably affect expected life. Our location data is obtained from our GIS and overlays such as corrosion maps and alpine areas.
- **Duty data** – refers to known factors that can cause one asset to degrade at a different rate than another. Our models use duty factors such as use cycles and loading.
- **Condition data** – refers to observations and measurements that arise from our asset inspection programs. Observations are qualitative, usually based on visual inspections.
- **Measured condition** – refers to quantitative measurements, such as condition assessment diagnostics like partial discharge measurements or insulation condition.
- **Reliability data** – is used to incorporate any known reliability problems that might arise from particular asset types. Examples might include asset types that have abnormally high failure rates or assets with poor parts availability that affect maintainability or repairability.

A summary of how our asset management data informs our asset health models is shown in Table 6.3.4.

Table 6.3.4 Asset management data used to inform asset health models

Asset health input type	Typical input data
Asset characteristics	Manufacturer and model, manufacture date.
Location	Indoor vs outdoor, corrosion environment from corrosion maps, Alpine operation from elevation. Localised harsh environments, for example: industrial pollution.
Duty	Reclose duty, operation counts and loading information, particularly for Power Transformers.
Observed condition	Visual assessment grades and scores.
Measured condition	Partial discharge measurements, insulation diagnostics, dissolved gas tests.
Reliability	Observations or tacit knowledge regarding the performance of types or subtypes of the asset fleet.

6.3 Asset lifecycle investment process continued

For presentation purposes, we convert CBRM asset health indices to the EEA asset health indicator format (H1 – H5). This provides a simplified presentation that is more appropriate for communicating with stakeholders. The EEA asset health indicators and typical CBRM conversions are shown in Table 6.3.5.

Table 6.3.5 Asset health indices equivalents

Asset Health Index	Commerce Commission and EEA	Typical CBRM AHI Range
H1	Replacement recommended	Greater than 7
H2	End of life drivers for replacement present, high asset-related risk	5.5 - 7
H3	End of life drivers for replacement present, increasing asset-related risk	4-5.5
H4	Asset serviceable. No drivers for replacement, normal in-service deterioration	2-4
H5	As new condition. No drivers for replacement	0.5 to 2

Probability of failure

The Asset Health Index is related to a quantified probability of failure through a Point of Failure (PoF) curve. This curve is calibrated by comparing the calculated health index of each asset fleet with historical failure rates. The calibrations are back-tested to ensure that the model produces predictions consistent with the recent past and the present observations. Forecasts of future asset health and the probability of failure are generated by rolling the model forward and assessing the impact of age on asset health and the probability of failure. The quality of calibrations depends on the availability of historical failure information related to the asset type.

Criticality and consequences

Criticality and consequences provide information on the significance of failure. Criticality is assessed in four dimensions: network performance, safety, financial, and environmental impact. It is calculated by firstly determining the baseline consequences of failure in each of these four dimensions, expressed in financial terms. Baseline criticalities are then modified to scale - up or down - individual asset consequences based on criticality factors. For a summary of how our asset management data informs our criticality models, see Table 6.3.6

Table 6.3.6 Asset information used to inform asset criticality and consequence models

Criticality dimension	Typical asset information
Network performance and safety	Number of customers affected, network configuration e.g., radial vs. mesh, restoration times, and response times.
Safety	Potential for failure to cause injury or death. Factors include location, such as population density, and the asset type, for example, oil vs. vacuum switchgear.
Financial	Potential cost of repairs, cost of remediating consequential damage. Factors include asset type, e.g., oil filled switchgear vs. vacuum switchgear, and location.
Environmental	Potential to cause environmental harm, for example, the release of SF6 gas or oil into the environment. Largely driven by asset type and whether there are location-specific mitigations in place.

6.4 Network development investment process

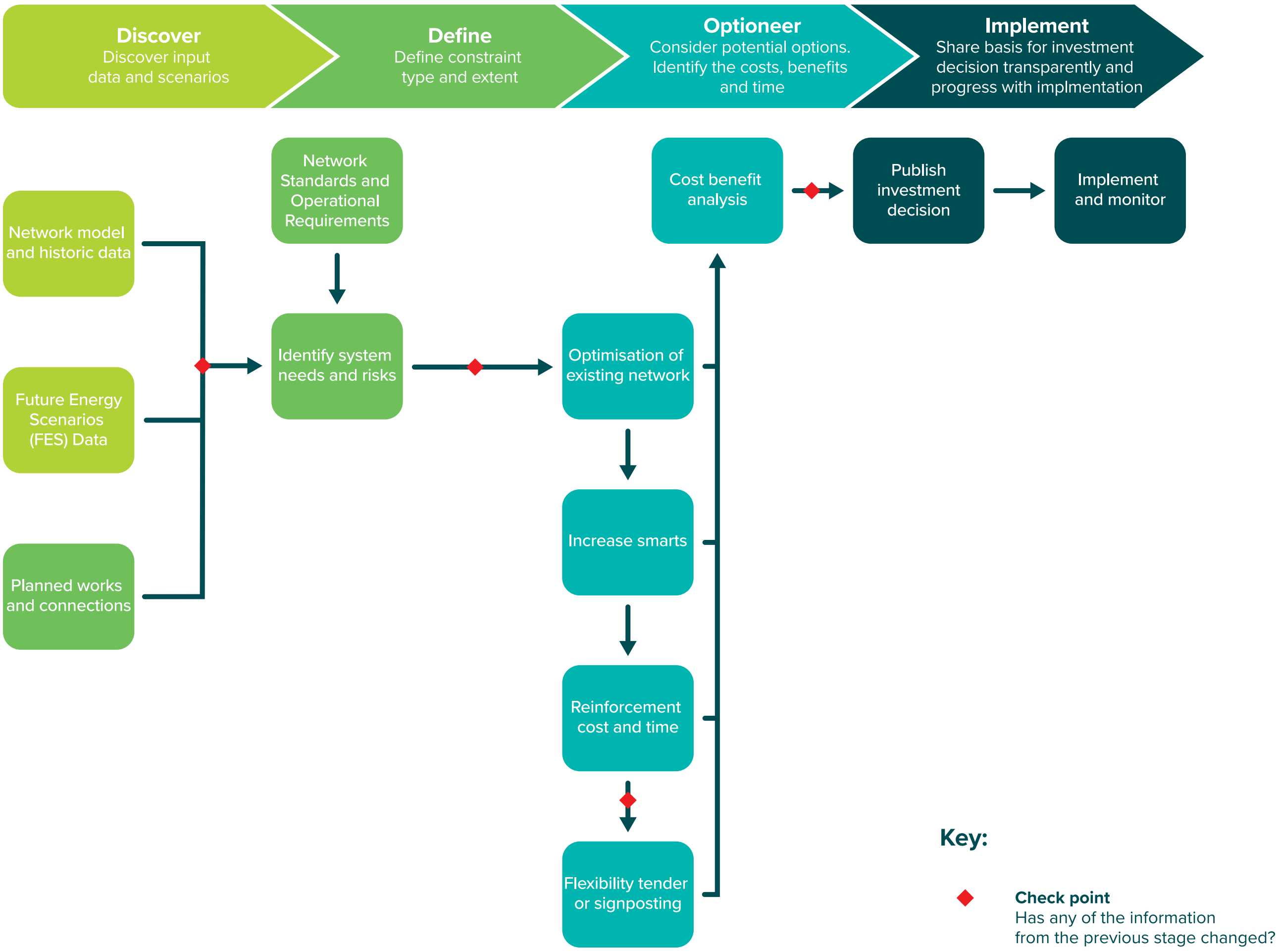
As detailed in Section 2, our network is facing significant change from increasing electricity demand due to decarbonisation and new ways of managing energy. This presents both challenges and opportunities to Orion in how we manage our network.

This section details the process around how we make network development investment decisions.

It includes identifying the constraints and developing solutions to address them. Non-traditional and network solutions are considered as part of the process.

We take a four-step approach to making decisions on investments in our infrastructure to deliver customer benefits over our AMP planning period. Each of these steps is shown in Figure 6.4.1

Figure 6.4.1 Orion process for making future-focussed investment decisions



6.4.1 Discover

Discover

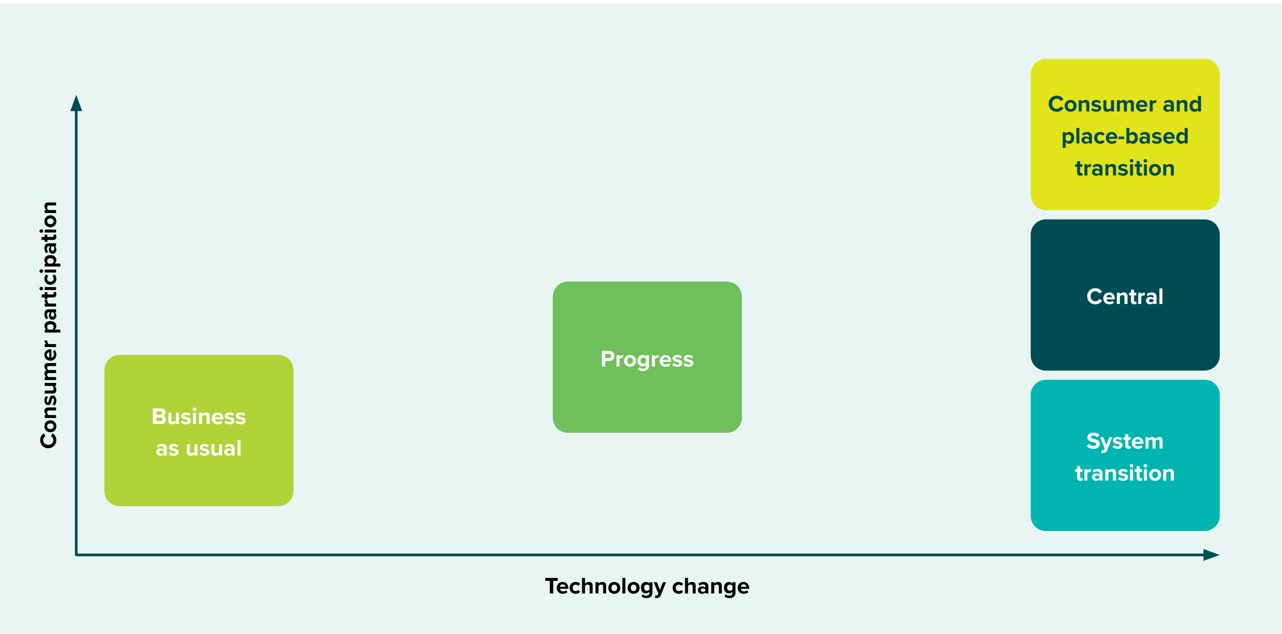
During the Discover step, we identify and analyse the drivers of growth and change, and the range of uncertainties of each. The first part of this process is to develop a load forecast to work out the areas that are likely to become constrained. Orion does this using future energy scenarios.

6.4.1.1 Orion's Future Energy Scenarios

Orion has crafted five future energy scenarios to gain a comprehensive understanding of potential outcomes and the factors influencing transitions between pathways. These scenarios, envisioning plausible futures in 2050, are shaped by key drivers such as technology change and consumer participation, mapped on different axes to depict anticipated changes.

Orion has crafted five future energy scenarios to gain a comprehensive understanding of potential outcomes and the factors influencing transitions between pathways.

Figure 6.4.2 Orion's Future Energy Scenarios



Our five scenarios are:

- **Business as usual** – an extrapolation of existing electrification trends, in a low growth world. Low change in technological uptake results in low economic growth and high climate change impact
- **Progress** – where electrification and change in consumer behaviour accelerates but doesn't result in full transition of the energy sector by 2050. There is some increased uptake of new technology and optimisation, with medium economic and population growth
- **System transition** – a centrally led transition of the energy sector is achieved through high uptake of new technology, but minimal shift in consumer engagement in the energy sector. Economic growth and population growth are medium. Climate change impacts are towards best case scenarios
- **Consumer and place-based transition** – where consumer and place-based optimisation combined with technology change achieves energy sector transition. High levels of network optimisation can be achieved through optimisation and place based optimisation leads to more efficient building and urban transport. Climate change impacts are towards best case scenarios

- **Central scenario** - medium growth in the Orion region and accelerating electrification closer to 2035. The scenario assumes some optimisation of charging demand and place based optimisation but low levels of EDB controlled flexibility. The Central scenario is the scenario we use for asset management planning, as our best / least regrets view of load growth over the next 10 years.

For a summary of the input assumptions, see Table 6.4.1. Detailed assumptions are available in our Orion Future Energy Scenarios report, available on our website.

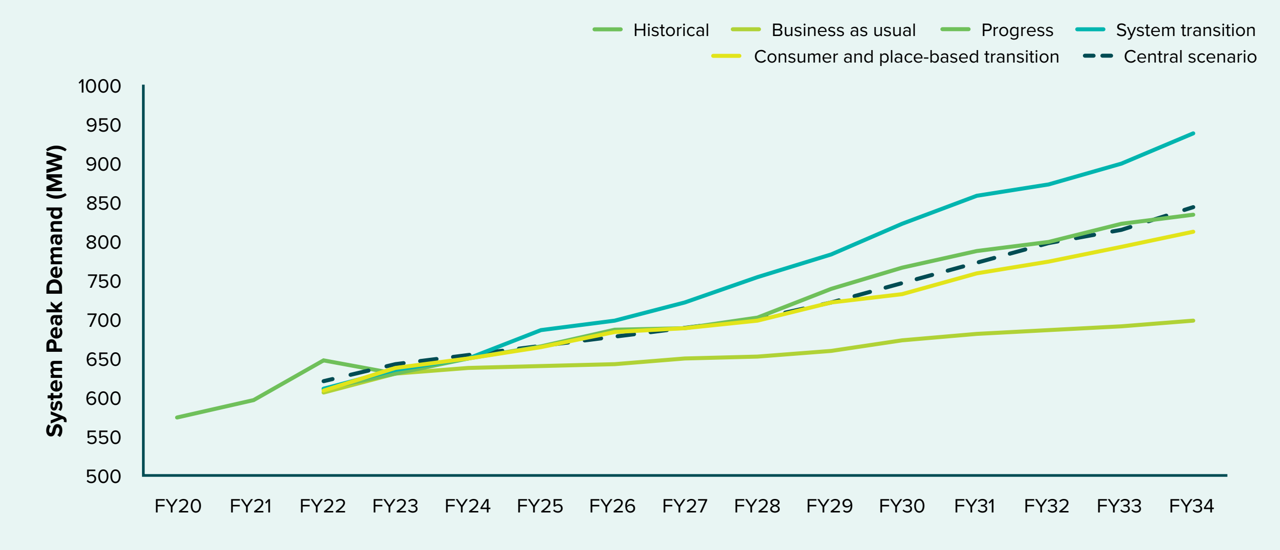
Table 6.4.1 Input assumptions for Future Energy Scenarios

Assumption	**Scenarios**				
	Business as usual	**Progress**	**System transition**	**Consumer and place-based transition**	**Central**
Population and residential growth					
Residential growth	Low	Medium	High	High	Medium
Residential efficiency	Medium	Low	Medium	High	Medium
Residential gas	Slow phase-out	Medium phase-out	Rapid phase-out	Rapid phase-out	Rapid phase-out
Industrial and commercial growth					
Economic growth	Low	Medium	Medium	High	Medium
Electrical intensity	Medium	Low	Medium	High	Medium
Commercial gas	Slow phase-out	Medium phase-out	Rapid phase-out	Rapid phase-out	Rapid phase-out
Electrification of transport					
Electrification uptake	Low	Medium	High	High	High
Mode shift	Low	Low	Low	High	Medium
Heavy transport electrification	Low	Medium	High	High	Medium
Electrification of process heat					
Electrification of boilers	Low	Medium	High	Low	n/a
Existing load management					
Hot water management	Slow reduction	Rapid reduction	Rapid reduction	Slow reduction	Medium reduction
Major customer demand response	No change	No change	No change	No change	No change
Batteries and vehicle to grid					
Battery uptake	Low	Medium	Medium	High	Medium
Vehicle to grid uptake	Low	Medium	Low	High	Medium
Solar					
Uptake	Low	Medium	Low	High	High

We conducted extensive consultation and engagement activities, including detailed discussions with key stakeholders, to refine our Future Energy Scenarios. The consultation aimed to ensure rigorous validation of inputs and assumptions, gather local evidence, and involve the community and stakeholders in collaborative discussions on the energy future. Key topics discussed included future population projections, transport decarbonisation pathways, and broader uncertainties. Feedback indicated positive engagement, with some organisations highlighting the need for considering wider societal shifts in scenarios, leading to adjustments and a recognition of the necessity for future investigations into additional impacting factors.

When making network development investment decisions we use the Central Scenario. Alternative scenarios inform the potential risk around the Central Scenario and what drives the differences between scenarios. The Central Scenario assumes high population growth in the Orion region and accelerating electrification closer to 2035.

Figure 6.4.3 Orion network peak demand forecast



The outputs of the modelling from our Future Energy Scenarios inform the load growth estimates for this AMP. The alternative scenarios inform the potential risk and what drives the differences between scenarios.

Our modelling shows system peak demand growth between 10% and 42% over the 10-year asset management planning period. Network wide peak demand results give an indication of the load growth we expect to see on the network. However, they don't directly relate to load growth and investment on the network. Different areas of the network and different assets will see load growth in different places and times and have varying levels of existing capacity. Section 8 outlines the impact of the different scenarios at GXP and zone substation level. It also discusses the specific network development investments and how they relate to the central scenario.

Table 6.4.2 Peak demand growth for five scenarios

	FY34			FY49		
Scenario	**Maximum Demand (MW)**	**Growth (MW)**	**% Change**	**Maximum Demand (MW)**	**Growth (MW)**	**% Change**
Business as usual	723	67	10%	839	183	28%
Progress	869	196	29%	1196	523	78%
System transition	959	285	42%	1381	707	105%
Consumer and place-based transition	840	166	25%	1056	383	57%
Central scenario	863	192	29%	1187	515	77%

6.4 Network development investment process continued

Business as usual

Despite having the lowest growth of our scenarios, the Business as Usual scenario has growth significantly above the historical growth rate. This is driven by continued electrification of transport and process heat on top of traditional growth drivers. These trends are already occurring and appear likely to continue in a business-as-usual world.

Orion would still need to make significant investments in infrastructure and smart technology to optimise our network utilisation. With continued electrification of transport, particularly if charging isn't optimised, upgrading low voltage network is likely to be required.

Progress

Despite lower rates of electrification than the transition scenarios, progress shows higher peak load growth than the consumer and place-based transition as demand from new technology is less optimised at the consumer level. The scenario also shows potential for conflict between optimising for a local network, and optimising for wholesale markets as more wholesale generation comes from solar and demand is pushed into the middle of the day.

In this scenario Orion would have more of a role in managing the balance between local demand and generation, as well as the balance between optimising the energy system and local network. Investment in infrastructure would also be required, at times rapidly, to service the increase in demand.

System transition

In System Transition peak demand growth more than doubles between now and 2050. This is driven by high rates of electrification and low optimisation at the consumer end of the energy system. In this scenario we see high growth in demand for some technology, particularly electric vehicles at peak times on the network, which exacerbates existing peak demand.

Orion would need to make significant investment in new infrastructure to service the greater peak demand in this scenario. There is particular risk from rapid electrification in this scenario, which would require proactive investment to build ahead of demand. Orion would need robust monitoring and tracking of changes to ensure it was ready ahead of time for change if this scenario eventuated.

Consumer and place-based transition

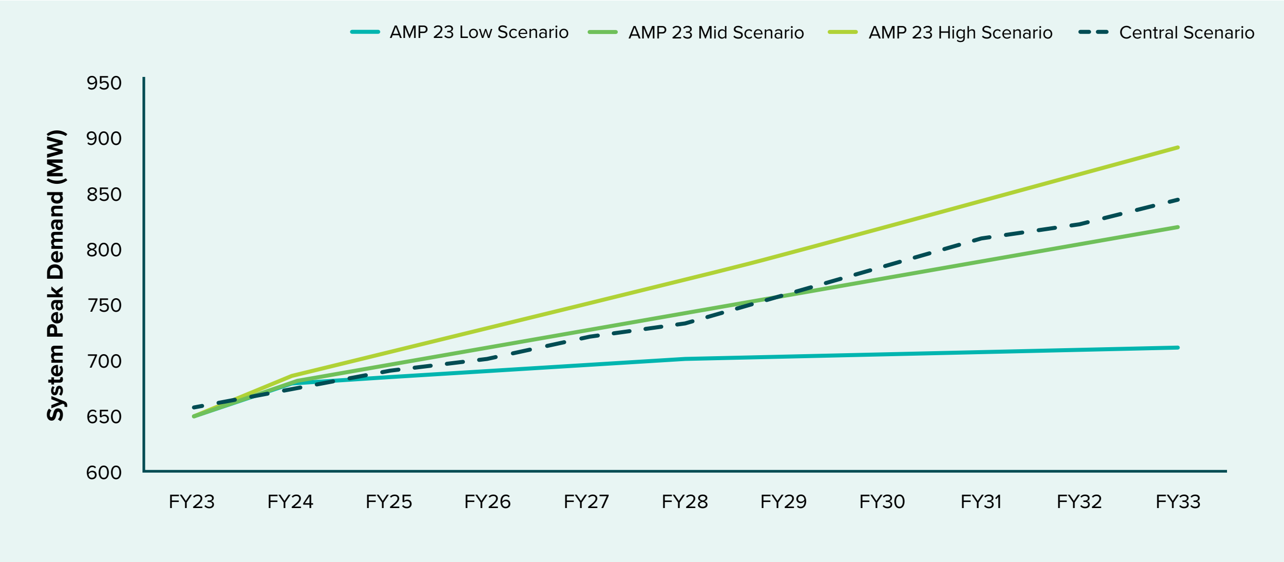
The Consumer and Place-based Transition scenario shows significant growth in peak demand in the 2020s and early 2030s driven by population and economic growth, and electrification of transport and process heat. Beyond 2034 demand grows at a lower rate, as more and more flexibility is introduced into the system.

In this scenario Orion's role would require significantly more management of flexible systems balancing local distributed generation and storage with demand throughout the day. It would also require significantly less infrastructure investment to service demand, though might require increased investment in smart systems and technology or markets to provide that balance.

Central scenario

Our Central scenario shows a slight increase in overall growth expectations compared with the 2023 AMP. It is roughly comparable with the middle of the range of scenarios from the AMP in 2023, however, it shows slower initial growth, and higher growth towards the end of the forecast period.

Figure 6.4.4 Comparison of AMP 2023 and AMP 2024 scenarios

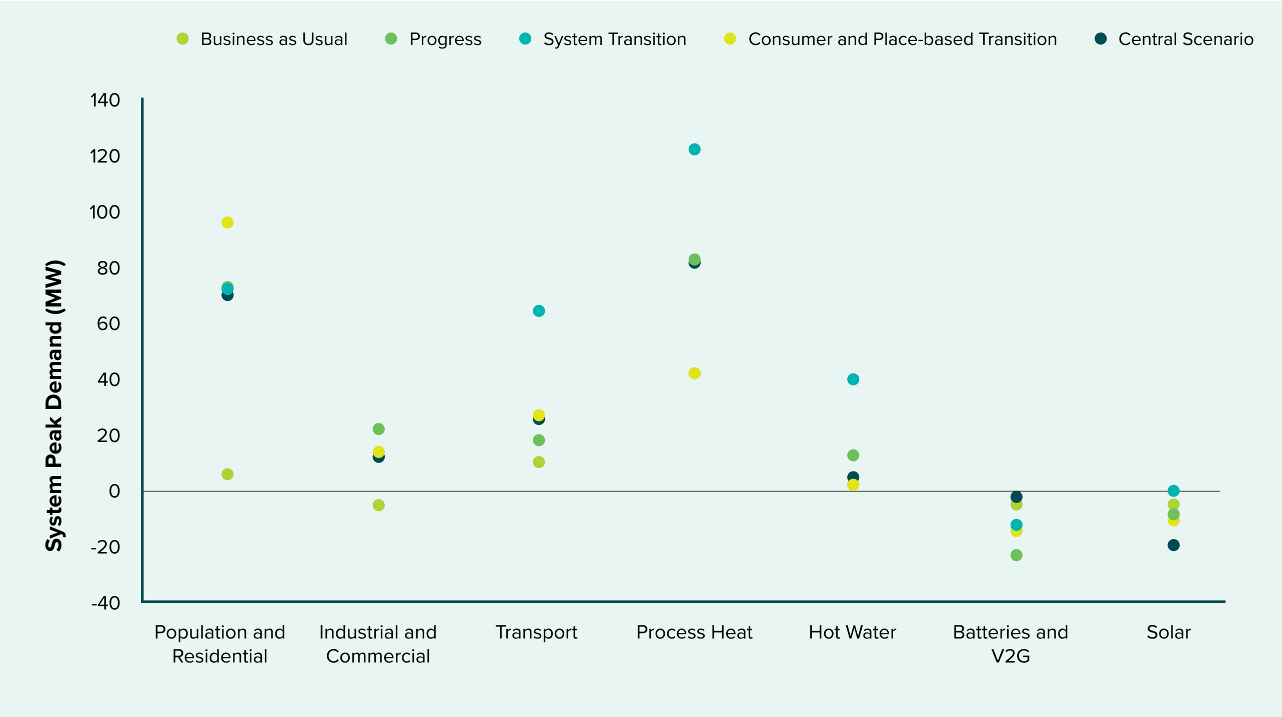


6.4.1.2 Forecast sensitivity

Analysing the spread between the different scenarios shows which drivers our scenarios are most sensitive to changing. This helps to inform where Orion needs to invest more effort into research and innovation to reduce the unknowns, invest more effort in monitoring and tracking changes and what might be the largest drivers of change over time.

In the short term most of the growth will come from residential, process heat conversions and transport. However, there is also a large spread between outcomes based on the assumptions about management of hot water load control. By 2034 there is a spread of 92MW in outcomes driven by high and low population assumptions, 82MW for differences in process heat assumptions, 53 for transport electrification and 38MW for hot water management.

Figure 6.4.5 Spread between scenarios FY34



For process heat conversions there have been good studies into the potential for conversions in our regions, and we have continued to engage individually with customers to understand their decarbonisation pathway. We have little or no agency when it comes to differing levels of population growth, but the spread in demand between different scenarios highlights the importance of understanding drivers of population growth and monitoring leading indicators. Transport demand is highly uncertain, but growth by 2034 is expected to be smaller compared with growth from population growth and process heat. This also highlights the need to better understand the risks of changing hot water load management, and the actions available to us to manage those risks in the future.

Looking further out to 2050, the level of uncertainty changes between different drivers. Population growth remains the driver with the most spread between scenarios (252 MW), but the spread between scenarios driven by batteries and vehicle to grid use, and transport become much wider as those technologies become more relevant. Further research and innovation into understanding the different decarbonisation pathways for the transport sector and the role of batteries in managing energy market and optimising markets will become more critical as uptake of those technologies increases.

6.4.1.3 Planned works and connections

Any planned works or known large customer load or generation connections are then applied to the Central Scenario to produce the output required for the next stage of the process.

6.4.2 Define

Define

Before weighing up our options we consider the type and extent of load or generation constraint. This includes where, when and for how long it is expected to occur. Some constraints will be very location specific, for example an LV feeder, and others widespread. Some constraints may only be forecast for several hours per year; and others will be frequent.

Network Standards and Operational Requirements are useful tools in helping with defining the constraints. Orion has been focussing on developing standards and requirements for our low voltage network. This includes our knowledge of the low voltage network and identifying the indicators of constraint.

Once we have identified the system needs and risks, we make a decision on the following points before moving to the next step:

- How many scenarios do we need to take forward to the optioneering step?
- How do we assess the acceptable level of risk e.g., Value of Lost Load (VoLL), SAIDI/SAIFI?
- When is a solution required?
- What operational requirements do we have?
- What level of HV Security of Supply does Orion and the customer require? See Section 6.4.2.2.

6.4.2.1 Low voltage constraints

Orion has worked in collaboration with, and commissioned various studies from EPECentre at the University of Canterbury to forecast the potential impact of electric vehicles and residential batteries on our low voltage network, down to street level.

The studies focussed on residential areas which were more likely to experience residential infill and EV clustering.

We are currently reviewing our LV strategy and have increased our forecast reinforcement budget to address expected constraints in the future.

Constraints were defined as:

- Transformers operating above 100% rated current
- Cables/Lines operating above 100% rated current
- Cables/Lines operating outside voltage regulations (230V ± 6%)

The results from this work enabled us to identify LV feeders which will be most vulnerable to load changes arising from the adoption of EVs and residential batteries.

Figure 6.4.6 highlights the number of new dwellings that could be fed from the existing residential distribution transformers in each Statistical Area Two, (SA2). The number does not consider the increasing uptake of zero-emission vehicles or the capability of overhead and underground reticulation, which would reduce the limit of dwellings that can be supported by existing electrical infrastructure.

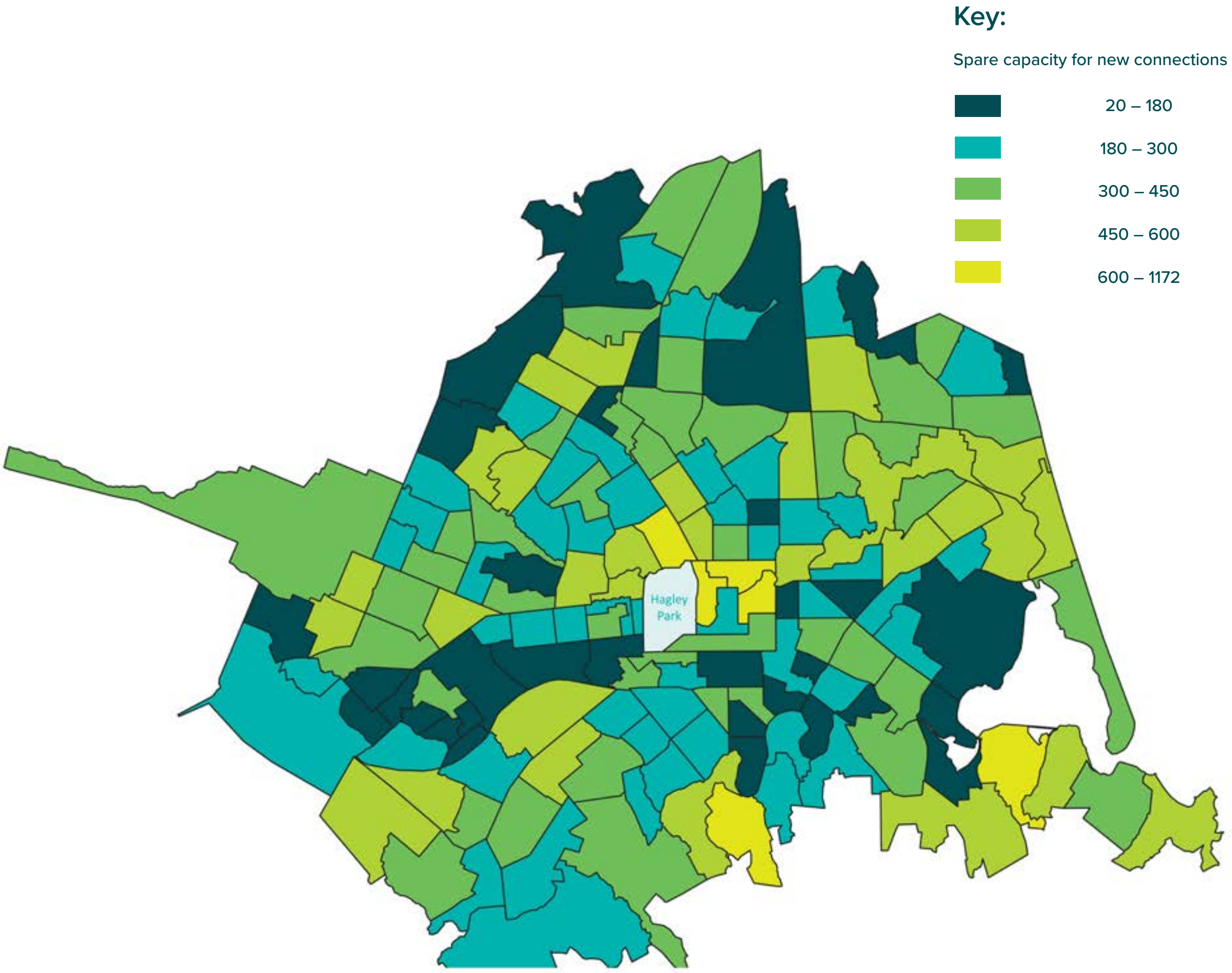
Our EV modelling to date indicates most of our low voltage network has sufficient capacity to meet demand in the short to medium term.

In the longer term, as EV adoption increases, our region's population grows and housing intensification increases, reinforcing our network will be required.

We are currently reviewing our LV strategy and have increased our forecast reinforcement budget to address expected constraints in the future.

Our forecasts of capacity and constraints on our LV network will be reviewed and adjusted with the knowledge we gain over the next few years from increased data on our LV network and information on how new technology is being used in homes.

Figure 6.4.6 Spare distribution transformer capacity in Christchurch city by SA2



6.4.2.2 HV Security of Supply Standard

Security of supply is the ability of a network to meet the demand for power in certain circumstances when electrical equipment fails or is damaged. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults.

Our HV network reliability and resilience is underpinned by security of supply. This is grounded in the flexibility we have built into our network that enables Orion to reconfigure it to provide power from alternative sources when needed.

In addition to our HV Security of Supply Standard, where possible major customers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We may also make changes to individual security of supply arrangements for existing major customers. Special arrangements are predominantly only provided to essential or high-profile customers such as hospitals, Lyttelton Port Company, Christchurch International Airport and public sports venues.

See our HV Security of Supply Standard in Table 6.4.3.

Our HV Security of Supply Standard:

- Provides a 'table of rules' that describes our desired level of service after different types of asset failure.
- The failure could be intrinsic or due to external influence, e.g. weather, or third-party damage.
- Defines whether an interruption may, or may not, occur following an asset failure and if so, the length of time that customers should expect to be without power.
- Sets the guidelines by which we build our network. It is one of the key factors behind our reliability performance.

The standard does not provide exhaustive detail and has been developed as a first pass guideline for our network development team. It errs on the side of caution by providing a high level of security for customers who place a high value on the supply of electricity. If our network security does not match the level of security required by the security standard, a gap in security is noted in Section 8.3.

Before implementing a major solution to eliminate a security gap, our Network Development team ensures the solution can be justified with economic analysis and a risk assessment.

6.4 Network development investment process continued

Table 6.4.3 HV Network Security of Supply Standard

Security Standard Class	Description of area or customer type	Size of load (MW)	Single cable, line or transformer fault, N-1	Double cable, line or transformer fault, N-2	Bus or switchgear fault
Transpower GXPs					
A1	GXPs supplying CBD, commercial or special industrial customers	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B1	GXPs supplying predominantly metropolitan areas (suburbs or townships)	15-600	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
C1	GXPs supplying rural and semi rural areas (Region B)	15-60	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
D1	GXPs in remote areas	0-1	Restore in repair time	Restore in repair time	Restore in repair time
Orion 66kV and 33kV subtransmission network					
A2 (Note 2)	Supplying CBD, commercial or special industrial customers	15-200	No interruption	Restore within 1 hour	No interruption for 50% and restore rest within 2 hours
A3	Supplying CBD, commercial or special industrial customers	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
B2 (Note 2)	Supplying predominantly metropolitan areas (suburbs or townships)	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B3	Supplying predominantly metropolitan areas (suburbs or townships)	1-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
C2 (Note 2)	Supplying predominantly rural and semi-rural areas (Region B)	15-200	No interruption	Restore within 4 hours (Note 1)	No interruption for 50% and restore rest within 4 hours (Note 1)
C3	Supplying predominantly rural and semi-rural areas (Region B)	4-15	Restore within 4 hours (Note 1)	Restore 50% within 4 hours and the rest in repair time (Note 1)	Restore within 4 hours (Note 1)
C4	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
Orion 11kV network					
A4	Supplying CBD, commercial or special industrial customers	2-4	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
A5	Supplying CBD, commercial or special industrial customers	0.5-2	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
A6	Supplying CBD, commercial or special industrial customers	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
B4	Supplying predominantly metropolitan areas (suburbs or townships)	0.5-4	Restore within 1 hour	Restore in repair time	Restore 90% within 1 hour and the rest in 4 hours (use generator)
B5	Supplying predominantly metropolitan areas (suburbs or townships)	0-0.5	Use generator to restore within 4 hours	Restore in repair time	Use generator to restore within 4 hours
C5	Supplying predominantly rural and semi-rural areas (Region B)	1-4	Restore within 4 hours (Note 1)	Restore in repair time	Restore 75% within 4 hours and the rest in repair time (Note 1)
C6	Supplying predominantly rural and semi-rural areas (Region B)	0-1	Restore in repair time	Restore in repair time	Restore in repair time

Notes:

1. Assumes the use of interruptible irrigation load for periods up to 48 hours.
2. These substations require an up-to-date contingency plan and essential neighbouring assets to be in service prior to the commencement of planned outages. During these outages, loading should be limited to 75% of firm capacity of the remaining in-service assets.

6.4.2.3 Network utilisation thresholds

Historic loading data from our Distribution Management System (DMS) and forecast zone substation and subtransmission utilisation figures are used to prepare our 10-year programme of network maintenance and development. Zone substations, subtransmission and distribution feeder cables are subject to four distinct types of peak load:

- **Nominal load** – the maximum load seen on a given asset when all of the surrounding network is available for service.
- **N-1 load** – the load that a given asset would be subjected to if one piece of the network was removed from service due to a fault or maintenance.
- **N-2 load** – the load that a given asset would be subjected to if two pieces of the network were removed due to a fault or maintenance.
- **N-bus load** – the load that a given asset would be subjected to if a single bus was removed from service due to a fault or maintenance. A bus is part of the configuration of equipment in a substation. The operational flexibility and reliability of a substation greatly depends upon the bus design.

As defined in our HV Security of Supply Standard, the location and quantity of load has a bearing on whether all or only some of the four peak load categories should be applied to an asset for analysis.

If the nominal peak load reaches 70% or the N-1, N-2 or N-bus load reaches 90% of the asset capacity a more detailed review of the surrounding network is instigated.

When we identify a capacity or security gap on our network we consider different options as solutions.

6.4.2.4 Network capacity options

When we identify a capacity or security gap on our network we consider different options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether. Where appropriate, we also consider network optimisation strategies such as flexibility to address capacity and security gaps without costly network upgrades.

When comparing different solutions, we use the Net Present Value (NPV) test. The NPV test is an economic tool that analyses the lifecycle cost of a projected investment or project, converting the value of future projects to present day dollars. NPV analysis generally supports the staged implementation of several smaller reinforcements. This approach also reduces the risk of over-capitalisation which may result in stranded assets.

The design of a zone substation and transformer is based mainly on the forecast load density of the area to be supplied and the level of the available sub-transmission voltage. A secondary consideration is aligning the capacity of new assets with standard equipment and designs.

Table 6.4.4 provides a summary of our standard network capacities.

Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair. Transformers and switchgear are more readily interchangeable, and the range of spares required for emergencies can be minimised.

When underground cable capacities are exceeded, it is normally most effective to lay additional cables. When overhead line capacities are exceeded, an upgrade of the conductor may be feasible. However, the increased weight of a larger conductor may require the line to be rebuilt with different pole spans and stronger hardware.

In this case it may be preferable to build another line in a different location that addresses several capacity issues. In Region A the installation of a new line will require a Resource Consent under the Christchurch District Plan.

New upper network capacity is installed only once new load growth has or is certain to occur. In the short term, unexpected or accelerated load growth is met by utilising security of supply capacity or procuring flexibility services to manage load. We discuss our approach to increased capacity in our architecture and network design document.

Table 6.4.4 Standard network capacities

Location	Subtransmission voltage	Subtransmission capacity		Zone substation capacity	11kV feeder size (Notes 1 & 2)	11kV tie or spur (Note 1)	11kV/400V substation capacity	400V feeders (Note 1)
	kV	MVA	Description	MVA	MVA	MVA	MVA	MVA
Region A	66	40	radials (historical approach)	40	7	4	0.2-1	Up to 0.3
		40-180	interconnected network					
Region A	33	23	radials and interconnected network	23	7	4	0.2-1	Up to 0.3
Region B	66	30	radials	10-23	7	2	0.015-1	Up to 0.3
		30-70	interconnected network					
Region B	33	15-23	interconnected network	7.5-23	7	2	0.015-1	Up to 0.3

Notes:
1. Network design requires 11kV and 400V feeders to deliver extra load during contingencies and therefore normal load will be approximately 50-70% of capacity.
2. 11kV feeders in Region B are generally voltage constrained to approximately 3-4MW so the 7MW capacity only applies if a localised high load density area exists.

6.4.3 Optioneer

Optioneer

With the constraint identified, we assess the options to address it. When preparing for growth, we consider a variety of options to address forecast constraints on the network, including traditional reinforcement and alternative solutions. Some options deliver social, environmental, and 'whole-of-system' benefits that are difficult to quantify. We also recognise decarbonisation is causing a fundamental change to the way we operate.

To ensure our network investments provide optimal value to customers, we explore more cost-effective alternatives to enhance utilisation before resorting to conventional reinforcement. These alternatives may involve influencing or managing demand through flexibility, hot water load management, and smart network solutions. These solutions benefit customers by enhancing network efficiency.

6.4.3.1 Network optimisation

The first step when developing options to address a constraint is to optimise the existing network. This can allow us to reduce, defer or eliminate the need for network capital expenditure. For example, optimising the current network configuration enables the controlled release of capacity through switching.

The first step when developing options to address a constraint is to optimise the existing network.

6.4.3.2 Increasing smarts

After all practical network optimisation has been done, we look for opportunities to increase use of smart technology such as smart meter data, ripple control, and special protection systems. These provide potential low-cost network solutions to address constraints.

6.4.3.3 Reinforcement scoping

Based on the type and extent of the constraint, we look at what network reinforcement could be done to address the issue. This includes traditional network build such as new cables and substations. Each of the potential reinforcement options will have their own costs, benefits, and time to deliver.

6.4.3.4 Non-traditional and flexibility services

We look for any opportunity to use non-traditional solutions to address network constraints. The assessment of when these are suitable is based on inputs from the previous steps. Currently we are considering flexibility services for sites with the following characteristics and are looking to expand this going forward as flexibility services mature:

- At 11kV network level or higher
- Capacity constraint at N-1 level
- 2 to 4 years away

In the future we will determine the 'payment budget' for a specific deferred investment using a commercial value model developed through Resi-Flex by Concept Consulting and in partnership with Wellington Electricity. Following a competitive tender process. we can assess whether the flexibility service is economically efficient and within the payment budget compared to network investment. The commercial value model has been shared with other EDBs via the ENA and there is interest in developing a common methodology to support investment decisions.

6.4.3.5 Cost-benefit analysis

A cost-benefit analysis is done to compare each of the potential options. The business case will then make a recommendation for a preferred solution. Before locking in a preferred solution, we cover these points:

- Can the solution/s be delivered in time?
- What is the optimal solution or combination of options?
- How can we finance the preferred solution?

Section 8 outlines the different network development projects we are planning for the AMP period, along with an indication if flexibility is a potential solution.

Once an option has been selected, projects are prioritised under the framework set out in Section 6.5. The decision-making process in Figure 6.5.1 outlines some of the factors considered when optioneering. This is a maturing process, enabled by the Network Transformation and Flexibility and Market Development Programmes described in Section 6.6.

6.4.4 Implement

Implement

After the optioneering process has been completed, and a preferred solution has been selected, we publish this investment decision and begin work on implementing the preferred solution. Monitoring is conducted along the way to keep track of the implementation progress and make any adjustments needed.

Section 8 outlines the network development projects Orion plans to deliver over the next 10-year period to meet our network and customer needs to support New Zealand's accelerated energy transition to meet New Zealand's decarbonisation targets.

After the optioneering process has been completed, and a preferred solution has been selected, we publish this investment decision and begin work on implementing the preferred solution.

6.5 Project prioritisation process

Prioritisation of network capex projects is a complex process that involves considering multiple factors that are both external and internal to Orion. Key considerations are managing risk, capitalising on opportunity and executing the company strategy. When scheduling our projects, factors we take into account are listed in Figure 6.5.1.

Figure 6.5.1 Factors we consider when prioritising our projects

Customer expectations	We give priority to addressing complaints most likely to impact customer supply through extended or frequent outages, or compromised power quality.
Waka Kotahi and local authority projects	We aim to schedule our projects to coincide with the timing of key infrastructure projects where locations overlap. This may cause us to bring forward or delay capital works projects to avoid major future complications and unnecessary expenditure. The most common activity of this type is coordination of planned cable works with any future road-widening or resealing programmes to avoid the need to re-lay or excavate and then reinstate newly laid road seal.
Service provider resource	We aim to maintain a steady worklflow to service providers and ensure project diversity within a given year. This ensures service provider skills, competence and equipment levels match our capital build programme year-on-year at a consistent level, reducing the risk of our service providers being over or under resourced.
Transpower projects	We endeavor to coordinate any major network structural changes adjacent to GXP with Transpower's planned asset replacement programmes, and provide direction to Transpower to ensure consistency with our subtransmission upgrade plans.
Internal projects	Where practical, we integrate asset related work and network development work where sites overlap to reduce overall cost and customer interruption.
Timing	The final decision to undertake investment in projects for the coming year depends on urgency. Seasonal timing to avoid taking equipment out of service during peak loading periods also applies, and we undertake projects in metropolitan areas in summer and projects in farming areas in winter where possible.
Asset risk	When it comes to asset classes such as poles and switchgear, the initial prioritisation for replacement is determined by monetised risks derived from the CBRM model. See Section 6.3.5 for a detailed explanation of how this process functions, along with insights into other forecasting approaches for asset replacement.

Projects not selected for next year are provisionally assigned to a future year in the 10-year planning window. When next year's project selection process is undertaken all projects are reviewed and, depending on changes in information and priorities, either maintained in the planning schedule, advanced, deferred, modified, or removed. Our objective is to smooth the works programme by deferring where we can or bringing projects forward where appropriate. For more information on deliverability see Section 9.

6.5.1 Project prioritisation tool

To bring more rigour to our project prioritisation process, we are developing a tool to help balance the competing priorities for capex investment in our network. The tool will help us develop a portfolio of capital projects most aligned with the Orion Group Strategy and which meet our asset management objectives. The tool values each project to create a prioritised lists.

To bring more rigour to our project prioritisation process, we are developing a tool to help balance the competing priorities for capex investment in our network.

The value framework includes a wide range of value measures intended to broadly represent all significant sources of value creation that investments bring.

The tool - currently in prototype form – will also capture high level risks and resource requirements for projects and show alignment with the Orion Group Strategy and Orion's asset management objectives, see Section 2.

We will use this tool to prioritise FY25 capital projects as the year progresses, taking into account where projects exceed budget or are expedited or delayed leading to reshuffling of our schedule.

6.5.2 Business case development

Once a project/programme scope has been defined in the development stage and prioritised, we document our thought process in business cases and/or Asset Management Reports (AMRs) for leadership team review and in some cases, board approval. Business cases support our network development and complex lifecycle management capital projects, and AMRs support our lifecycle management portfolio programmes of work. Business cases are often underpinned by an overarching strategic business case which addresses our security of supply architecture standards.

Orion uses an asset planning decision framework to decide the complexity of a business case based on the network project type proposed, see Table 6.5.1.

Table 6.5.1 Asset planning decision framework

	Level 1	Level 2	Level 3
Project type	Renewal, replacement, AMR	Minor project, renewal, replacement	Security of supply, architecture (reticulation or protection), major project, renewal, replacement
Principal criteria	Single solution	Risk based	Cost benefit analysis of multiple options
Primary driver	Need for routine maintenance / inspection, like for like renewal	Safety, regulatory compliance, obsolescence, renewal / reinforcement	Weighing up options to improve reliability, resilience, future network, renewal / new build, overhead to underground conversion
Customer impact and engagement	Assessing customer impact, talking with customers i.e., from ongoing outage event analysis, customer enquiries, complaints, surveys, workshops, focus groups and Customer Advisory Panel		Specific project engagement and / or consultation

6.6 Network transformation and flexibility

Orion's network transformation is shifting our network from the traditional one-way power flow to a smart network, emphasising renewable energy integration, smart grid technology, and fault prediction through advanced analytics. At the same time, we are focusing on flexibility to engage customers in market-based solutions to ensure efficient capacity delivery.

6.6.1 Network Transformation Roadmap

Orion has developed a Network Transformation Roadmap. Its aim is to enable and support our community to sustainably transition to a low carbon economy – ensuring everyone can participate, and the environmental cost of doing so is minimised or removed where possible. Our roadmap aims to ensure our customers can take advantage of new low-carbon technologies and provide them with greater freedom to manage their energy use to achieve their decarbonisation goals. The 10-year plan will enable us to deliver on the critical focus areas for Orion's Network Transformation Programme which are to:

- Leverage access to smart meter and LV monitor data to create improved visibility of our assets and activity on our network, particularly Distributed Energy Resources (DER) and Low Carbon Technologies (LTC).
- Leverage that data via advanced analytics and enhanced capability to derive power system insights such as system constraints, network performance improvements and efficiency through optimal investment.
- Ensure we can host increasing DER and LCT connections while maintaining the required network safety, stability and resilience.
- Unlock latent capacity in our network which becomes available using improved visibility, smart technology and non-traditional solutions – such as flexibility.
- Maximise the two-way throughput of energy across our network.

To achieve these outcomes, we have five network transformation workstreams underway:

- **Identifies and supports business culture and process adaptation** – identifies what is required to build human capability and reshape some business processes, organisation structures and people roles and responsibilities as we develop intelligent Distribution Network Operator (iDNO) capability. See Risk Section 5.8.5 and 5.8.9.
- **System visibility and network data integration** – ensures real-time awareness of activity on our network and asset information to better understand network performance. This also provides visibility of DER / LCT and bidirectional energy flow - from behind the meter to GXP level. This workstream enables two-way data flow, integrates data sourced from Orion and third-party assets / platforms as well as establishes robust systems to support data confidence with very high data integrity and quality.

Our roadmap aims to ensure our customers can take advantage of new low-carbon technologies and provide them with greater freedom to manage their energy use to achieve their decarbonisation goals.

- **Power systems insight enablement** – proactive identification of current and future network constraints and failure modes that enables data-driven network performance improvement, cost reduction, risk management, and reduced environmental impact.
- **Scaling DER / LCT connections and conversions** – ensures our network enables / does not block the path to customers decarbonising at scale and pace, by efficiently accommodating on our network the growing numbers of renewable energy sources, electric vehicles, energy storage, and other LCT.
- **iDNO enablement –** enables the intelligent Distribution Network Operator (iDNO) capability required to seamlessly maximise the throughput of energy across our network with high penetrations of DER / LCT under utility, market or price-led operation / enablement modes.

6.6.2 Smart network solutions

In addition to flexibility and load management, Orion also employs other techniques to optimise network utilisation. Examples are:

- **Special Protection Schemes, Active Network Management** – to optimise the use of system and to provide greater levels of reliability, we often use multi-feeder parallel networks at a subtransmission or distribution level. These systems sometimes use a Special Protection Scheme (SPS) and work by actively isolating healthy networks to ensure overloads and faults do not result in wider network outages. The situations where SPSs operate are generally very low probability and SPSs are often temporary before a permanent solution is found.

- **Adaptive Power Management and Dynamic Operating Envelopes** – in the past where temporary loads have been connected on constrained areas of our network, we have used Dynamic Operating Envelopes (DOE) driven by real-time measurements to signal pending constraints to customers to indirectly manage our zone substation load. DOEs provided a tool to enable the over-allocation of static network capacity to operate within the dynamic capability of, for example, a power transformer.

We are also looking at ways to enable the use of Adaptive Power Management to leverage the diversity of load with dynamic capacity allocation for major customers who have flexible capacity requirements. In the future we will also look to utilise dynamic asset ratings to enable greater utilisation of our assets.

6.6.3 Network visibility

Orion has good visibility and control of our HV network through use of SCADA-enabled field devices at most circuit breakers and zone substations. This data is used to assess asset utilisation and performance to inform our network investment.

However, this is not the case with our 400V LV network which was planned for reasonably stable, passive household loads with one-way power flow. As more customers adopt technologies such as EVs, and as more multi-unit housing intensification occurs, these street-level LV systems may experience increasing levels of constraint.

Given Orion's LV network supplies more than 99% of our customers, developing its visibility and capability is essential to efficient management of our network and facilitating customer choice.

We have two LV initiatives to increase LV network visibility:

- LV monitoring
- Smart meter information gathering

These initiatives will help us to:

- Provide information to guide our operational, planning and investment activities.
- Develop improved forecasting and modelling techniques.
- Facilitate customer choice by better enabling customers to charge batteries during off-peak times and potentially export power into our network at peak times – thereby lowering their net cost of electricity.
- Improve customer service through increased real-time identification and location of faults.
- Identify poor performing feeders and quality of service to individual customers, which will then allow us to target actions to improve customer experience.
- Reduce capital and operational costs by early warning of power quality problems, such as phase imbalance.
- Enhance safety as real- or near-time monitoring provides measurements which will better inform us of what is live, de-energised, and outside of regulatory limits.
- Display constraints in our network online, enabling others to participate in developing solutions.

See Section 3 for details of performance of the LV monitoring and smart meter information gathering programmes.

6.6.4 Flexibility and market development

Demand-side-flexibility is where consumers shift their demand in time or alter their total demand in response to an external signal. This can be through a manual change in consumer behaviour or automated through ripple relays or smart devices responding to signals.

The transition towards net-zero emissions is driving a need for more demand-side flexibility and to support the integration of intermittent renewables and efficient development of electricity networks. Consumer and distributed energy resources such as electric vehicle batteries will play a crucial role in our future energy system and could give our community more agency in how and when they use their electricity.

Orion's objective is to maximise opportunities for customers and other stakeholders to participate in flexibility and other market-based solutions. In FY24 we established a Flexibility and Markets Development Programme to coordinate areas within Orion and the wider sector to achieve this.

The programme includes activity related to:

- Emerging strategy and influencing the future of flexibility.
- Engaging with providers and users of flexibility.
- Determining the value of flexibility and incentives.
- Developing and utilising flexibility products and services.
- Coordinating to ensure visibility and secure operation of flexible resources.
- Supporting consistent flexibility standards and procedures across the industry.

Orion's objective is to maximise opportunities for customers and other stakeholders to participate in flexibility and other market-based solutions.

Orion is engaging and working with parties to gather global and local insight, receive feedback and co-design solutions to ensure we understand and meet customer and other stakeholder's expectations.

Our approach is both customer-centric and collaborative. To complement our existing tools that are critical to system security, such as hot water load management, we are developing innovative technical and commercial solutions to enable alternative solutions for customers. We recognise the need for sector collaboration and innovation to ensure customers have access to the information they need to make informed decisions about demand-side-flexibility. Allowances for innovation and non-network solutions are vital to stimulate the development of novel solutions and the capability to implement these. Orion is actively working with customers and stakeholders across the energy sector through a range of initiatives, both strategic and practical.

6.6.4.1 Whole-of-system coordination

Flexibility can provide value across the electricity supply chain including through the wholesale market, ancillary services, transmission and distribution networks and to consumers themselves. In some cases, a flexible resource can contribute to more than one need known as 'value stacking'.

To ensure we efficiently plan and develop our network, it is increasingly important we understand the 'value stack' and the impact of other uses of flexibility on network load. Coordination of flexibility across the electricity supply chain in both planning and operational timeframes is critical to maintain security while supporting decarbonising in a cost-effective way.

Through our own projects, the FlexForum, Electricity Networks Aotearoa (ENA) and engagement in other industry wide forums and programmes, we are coordinating to unlock the value of flexibility to consumers and the wider energy system. Building on our work with the South Island Distribution Group on Distribution System Operation, we are leading a project through the ENA Future Network Forum to define the roles and functions to enable distributed flexibility and consider the different industry architecture to fulfil these.

Orion is engaging and working with parties to gather global and local insight, receive feedback and co-design solutions to ensure we understand and meet customer and other stakeholder's expectations. This approach is demonstrated through the Resi-flex project, where research with residential customers has informing the development of incentives for flexibility this year. Upcoming trials with real-world consumers will demonstrate how effectively these can encourage flexibility will inform future expenditure forecasts, support efficient network development and manage the cost to customers.

6.6.4.2 Enabling flexibility for distributors

Electricity distribution networks can use a range of mechanisms to enable flexibility, depending on the type of constraint and desired response. Orion is maintaining and exploring new mechanisms to enable flexibility across each of these areas.

Price-led mechanisms – where price is used to signal the cost-of-service provision and network utilisation. When we review our prices each year, our goal is to set prices that encourage the efficient and cost reflective use of our network for the long-term benefit of our customers. Information on our pricing is published on our website. Examples of our pricing that stimulates flexibility are:

- **Control period pricing signals for major customers** that are signalled in real-time provide a financial signal to reduce or delay power usage, and if possible, switch power sources.
- **Our Irrigation Interruptibility Scheme** where we pay rebates to customers who allow us to interrupt their power supply to designated irrigators during a capacity emergency to help keep the power on for the wider community.

Market-led or contracted flexibility – where payments can be made for a non-network solution / flexibility service. These are emerging globally and locally to defer or avoid new investment in traditional network assets. As they are agreed in advance, opt in and location specific, they can provide a more targeted and cost reflective payment to address local network needs. An example is:

- **Orion's Lincoln Flexibility Service** – where we have contracted for a flexibility service to defer capital investment. Large scale residential growth in Lincoln is raising the demand for electricity in the area. Traditionally that growth in demand would require more electricity network to be built. Instead, we ran a competitive procurement process and have contracted with Ecotricity who will provide support from residential batteries to reduced peak electricity in the area during winter in 2024 and 2025.

Utility-led mechanisms – where networks can directly control flexible resources or apply standards to achieve flexibility. Orion has a long history of managing peak loading to promote efficient operation of the network and avoid or defer costly transmission and distribution network reinforcement.

- **Hot water load control** – currently, the primary mechanism we use to facilitate load management on our network is through control of ripple relays. Orion uses ripple control technology to manage load in two ways: Peak load control of hot water heating and fixed time control of water and night store heating. Hot water systems can also be managed through other smart devices. We will continue to maintain and leverage hot water load management through ripple while exploring the feasibility and value of alternative solutions that maximise value to consumers.
- **Upper South Island Load Manager** – in addition to controlling hot water in our region, Orion also provides a service to coordinate the management of hot water cylinders in other distributors' networks to manage peaks on Transpower's upper South Island network. We do this via a specifically designed upper South Island load manager which communicates with Transpower and all upper South Island distribution network companies. Co-operation and the coordination of upper South Island load management enables us to reduce peaks without excessive control of hot water cylinders.

Orion will continue to complement existing tools critical to system security and managing cost to customers by developing innovative technical and commercial solutions that give customers choices for their energy use.

6.7 Innovation strategy and initiatives

Our energy system is transforming to enable society's equitable transition to a low carbon, resilient future. While the broad direction of the transition is clear, there are many challenges and opportunities to be addressed along the way. Orion is committed to collaboration with our energy sector colleagues, customers and key stakeholders to explore, learn and innovate together to co-create the energy future our community needs.

Innovation is critical to ensure our customers' needs are met efficiently and cost effectively as the energy system rapidly evolves over the coming years.

In FY24, Orion developed its Innovation Strategy, which includes a stocktake of innovation practices and case studies which are updated annually. Our Innovation Strategy is available on our website.

We will apply to the Commerce Commission for an Innovation Project Allowance for eligible innovation project costs during the DPP3 period (FY20-25) up to the maximum allowed for Orion by the Commerce Commission.

Innovation is critical to ensure our customers' needs are met efficiently and cost effectively as the energy system rapidly evolves over the coming years.

7 Managing our assets

224,000
Customer connections

8,000
Square kilometres network coverage

14,300
Kilometres of lines and cables

52
Zone substations

90,000
Orion power poles

5,800
Distribution substations

Photo: Pole maintenance and effective management of vegetation nearby is building our network reliability and resilience.

Contents

Contents continued

7.1 Introduction

This section describes our approach to managing the lifecycle of our assets to achieve our asset management objectives and meet the expectations of our customers.

Managing the entire lifecycle of our assets involves the design and delivery of asset inspection, maintenance, refurbishment, replacement and disposal programmes. In developing our programmes, we take a risk-based approach using asset condition and performance data to understand asset health and the probability of failure.

We are projecting an average annual capital expenditure of $65m and $40m in network asset operational expenditure over the next five years. This represents a significant increase in spending compared to our current levels.

Over the next decade, our focus remains on replacing aging assets dating back to the 1960s to the 1980s and ensuring the continued reliability, resilience and safety of our network, which has been performing well. While the overall number of assets to be replaced remains consistent with previous forecasts, there are specific areas where we're anticipating an uptake in work to enhance resilience which has been top of mind for our customers.

These include:

- **Adding poles in high wind zones** to our standard end-of-life asset replacement programme. Our initial analysis indicates these poles may pose higher risks due to their construction and design not aligning with future environmental conditions influenced by climate change.
- **Implementing physical climate adaptation measures for distribution substations.** We have allocated budget to replace or re-design the boundary boxes against climate change impacts, particularly in flood-prone areas.
- **Increasing vegetation management efforts**, prioritising areas most susceptible to severe wind events to bolster the resilience of our overhead network. Following Cyclone Gabrielle, the Electricity Distribution Sector Cyclone Gabrielle Review highlighted that the majority of outages in that event were due to vegetation.
- **Acquiring conductor condition data** so we can proactively develop a risk-based conductor replacement programme, ensuring our safety and reliability service levels are maintained as assets approach the end of their lifespan, where this is anticipated toward the end of the planning period.

For our overall planned operational and capital expenditures, see Figure 7.1.1 and Figure 7.1.2.

Figure 7.1.1 Asset operational expenditure – 10-year forecast (real)

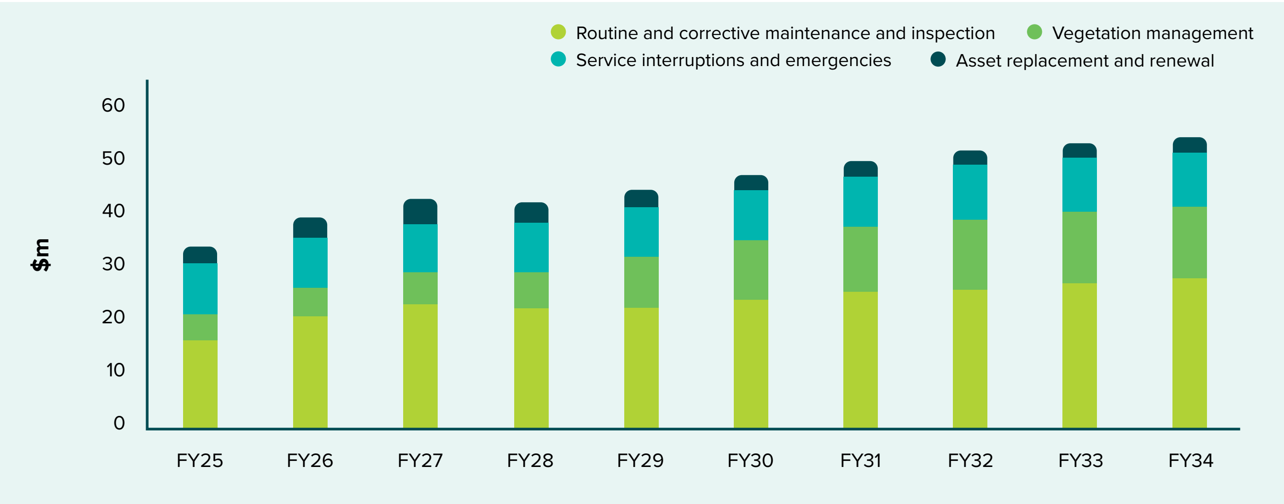
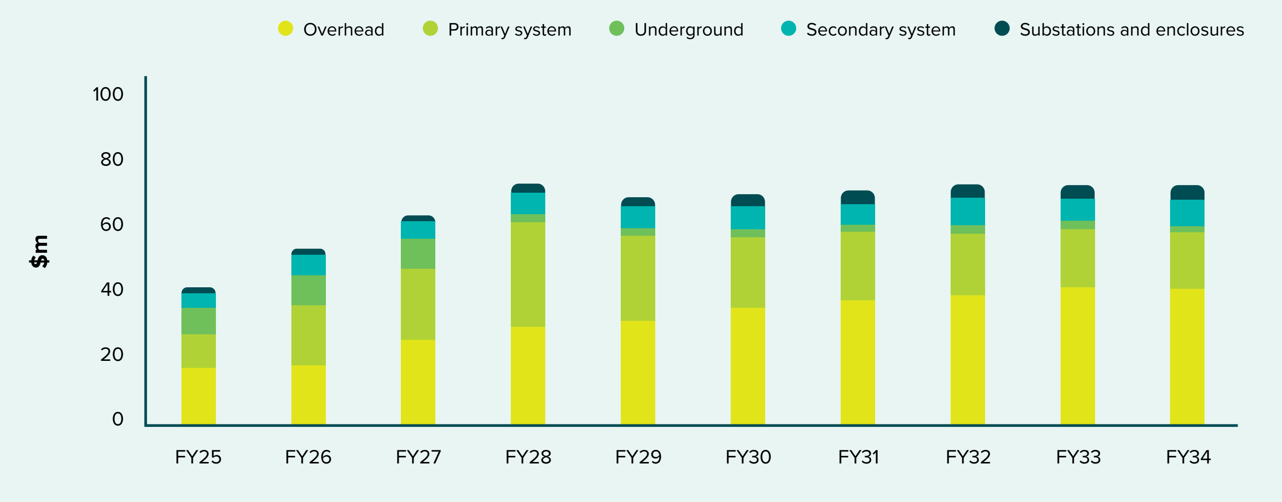


Figure 7.1.2 Asset capital expenditure – 10-year forecast (real)



7.2 How this section is structured

For each asset class we have taken a consistent approach to describing the assets, their current health and our plans for inspection, maintenance and replacement. In the following Sections 7.3 to 7.20, for each asset class we provide:

Summary

A summary of the role of the asset in our network, our objectives for the asset, any issues and plans for the asset class.

Asset description

A brief description giving the type, function, voltage levels and location and distinct components of each asset class. The number of units are also provided together with the age profile.

Asset health

Condition
The health of an asset represents the asset's current condition as a Health Index (HI) profile. An age profile is also provided if not already outlined in the asset description. We use the Condition Based Risk Management (CBRM) models to calculate the HI and Probability of Failure (PoF) of each individual asset.

The Health Index definitions are:

- **H1:** replacement recommended
- **H2:** end of life drivers for replacement present, high asset related risk
- **H3:** end of life drivers for replacement present, increasing asset related risk
- **H4:** asset serviceable, no drivers for replacement, normal in-service deterioration
- **H5:** as new condition, no drivers for replacement

Reliability
We look at the performance of the asset class. Where relevant, we discuss its contribution to SAIDI and SAIFI or faults per 100km.

Issues and controls
A table is provided to outline the failure causes and mitigation or control measures for the asset category. This provides context for the asset condition, maintenance and replacement plans.

Maintenance plan

Here we provide the scheduled maintenance work plans that keep the asset serviceable and prevent premature deterioration or failure. A summary of the asset class's maintenance strategy, the maintenance activity and frequency is also provided. Maintenance expenditure forecasting is based on known historical maintenance costs and our projected maintenance programmes.

Replacement plan

These are forecast work plans to replace or renew an existing asset. We also briefly outline the options we explore in optimising the replacement work if they are additional to those described in Section 6.3.2. A summary of upcoming programmes and work is also included. Replacement expenditure forecasting is based on known historical replacement costs and projected replacement volumes.

Disposal
We list any of the activities associated with disposal of a decommissioned asset.

Orion has more than 5,800 buildings, substations, kiosks and land assets that form an integral part of our distribution network.

7.3 Network property

7.3.1 Summary

Orion’s network has more than 5,800 buildings, substations, kiosks, and land assets that house the necessary plant and equipment for delivering our services. These assets play a crucial role in ensuring the secure and efficient operation of the enclosed equipment. For buildings, it is important to maintain a physically secure environment that is also clean and dry.

Our property assets are often integral to the capability of network equipment to withstand extreme events such as storms, earthquakes, or the long-term impacts of climate change. Many of our network property assets are also situated within the communities we serve. When maintaining or building new assets, Orion is sensitive to the needs of the local community and environment, adhering to aesthetic standards that align with Orion's brand.

Network property assets support our asset management objectives by providing accommodation for our network plant and equipment. Our objectives for network property assets include:

- To secure network equipment to ensure public safety by preventing both intentional and inadvertent unauthorised access.
- Provide an appropriate environment for network equipment to function safely, reliably, and achieve its design life.
- Contribute to the network's resilience by having the capability to prevent damage and allow continued operation of network equipment following HILP events, as required by our network resilience plan.
- Accommodate projected environmental changes caused by climate change.
- Be aesthetically acceptable to the local community and other stakeholders and align with Orion's brand.
- Comply with all required codes and regulations.

7.3.2 Asset description

7.3.2.1 Zone substations

Zone substations are critical hubs in our network, housing high-voltage infrastructure that typically serves multiple suburbs. Our substations are of various types and ages, with the majority constructed from concrete block, followed by modular prefabricated, tilt slab, and brick buildings. Some zone substation sites also feature outdoor yards, requiring security fencing and grounds maintenance.

In Orion’s zone substations, typically one of the following takes place: voltage transformation from 66kV or 33kV to 11kV; redistribution of two or more incoming 11kV feeders. In many, ripple control plant for remotely managing load associated with customer’s hot water heating is installed.

For a summary of Orion's zone substations, see Table 7.3.1, and for their age profile, see Figure 7.3.1.

For a map of our zone substations’ location in Region A, see Figure 8.4.1 or Region B, see Figure 8.4.5.

Zone substations are critical hubs in our network, housing high-voltage infrastructure that typically serves multiple suburbs.

7.3 Network property continued

Table 7.3.1 Zone substation description and quantity

Voltage	Quantity	Description
66kV	2	Norwood is a Region B 66kV GXP connected switching station and future zone substation commissioned in 2023. Marshland is a 66kV indoor switching station and future zone substation located in Region A.
33kV	1	Islington is a 33kV GXP connected switching station and zone substation that supplies the Region A 33kV / 11kV zone substations.
66kV / 11kV	28	Nineteen substations are in Region A, with the rest in Region B. Nine urban substations in Region A, including Armagh, Dallington, Lancaster, McFaddens, Waimakariri, and Belfast, have an exposed bus structure inside a building. In Region B, nine substations, like Brookside, Dunsandel, Highfield, Killinchy, Larcomb, Kimberley, Greendale, Te Pirita, and Weedons, are supplied by overhead lines and have outdoor structures.
66kV / 33kV & 66kV / 11kV	1	Springston rural zone substation is supplied by an Orion tower line from Transpower's Islington GXP.
33kV / 11kV	16	These are mainly in the Canterbury rural area and on the western fringe of Christchurch city. Most have some form of outdoor structure and bus-work. Zone substations at Annat, Bankside and Little River have 66kV structures but are currently operating at 33kV.
11kV	4	All situated in Region A, these substations are directly supplied by three or four radial 11kV cables, without power transformers. Without any outdoor structure or bus-work, none of the 11kV zone substations possess such features. We may decommission some of these substations due to evolving load profiles in specific network areas.
Total	**52**	

7.3.2.2 Ground-mount distribution substation

Orion has various types of ground-mount distribution substations, see Table 7.3.2. For an age profile for distribution substations, see Figure 7.3.1 and for kiosks, see Figure 7.3.2. Where our equipment is housed in buildings, many of these buildings are owned by our customers.

Table 7.3.2 Ground-mount distribution substation type

Type	Quantity	Description
Customer building	202	Customer substations are Orion substations within a customer's building, typically containing at least one transformer, an 11kV switch unit, and a 400V LV distribution panel. Additionally, there may be 11kV circuit breakers or ring main units.
Orion building	248	Orion-owned substation buildings are standalone structures, varying in size and construction.
Kiosk	3,427	Our steel kiosks, locally designed and manufactured, come in two main styles: older high style and the current low style. Full kiosks, varying in size and construction, typically house a transformer with an 11kV switch unit and a 400V LV distribution panel.
Outdoor	879	Configurations vary, but typically, these consist of a half-kiosk with 11kV switchgear and a LV distribution panel, like a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or side of the kiosk.
Pad transformer	868	A transformer only, mounted on a concrete pad, supplied by high-voltage cable from switchgear at another site. Transformers are typically uncovered.
Switchgear cabinet	209	Cabinets containing only 11kV switchgear.
Total	**5,833**	

Figure 7.3.1 Substation buildings age profile by zone substation and distribution substation

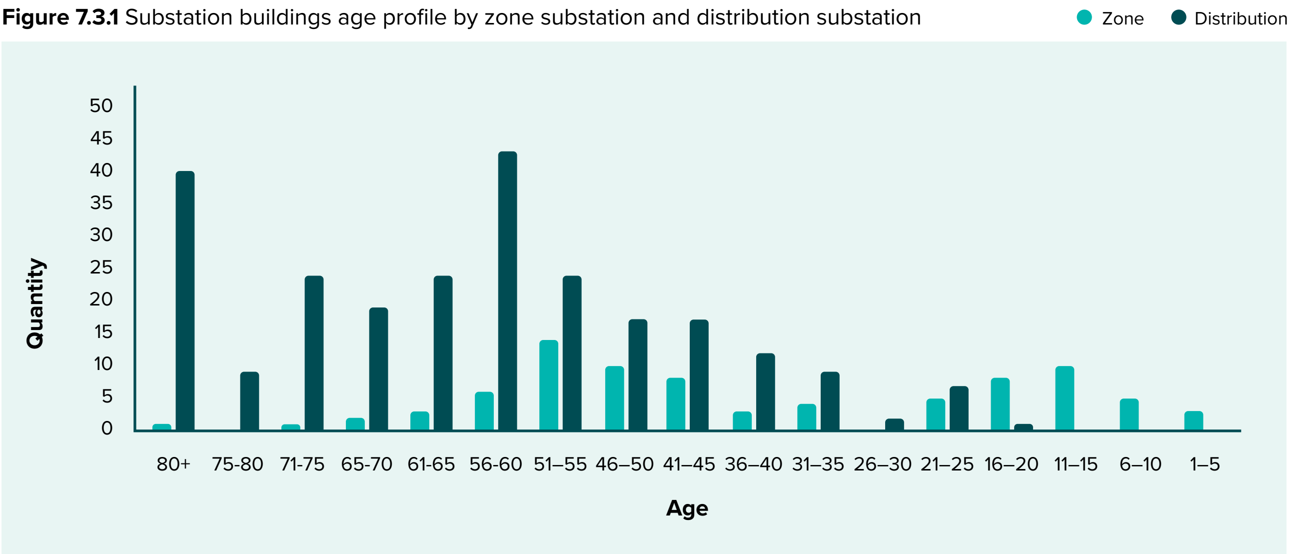
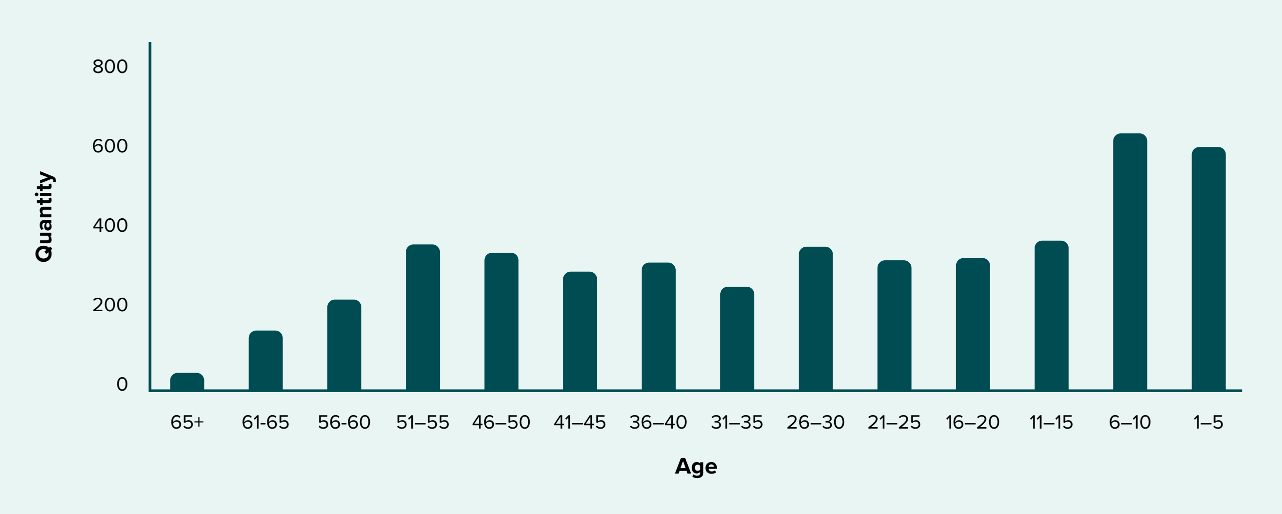


Figure 7.3.2 Kiosk age profile



7.3.3 Asset health

7.3.3.1 Condition

We routinely inspect our zone and distribution substation buildings, assessing their physical security, weather tightness, general condition, cleanliness, and appearance. Any deterioration is documented and scheduled for repair or remediation, while longer-term repairs or replacements are planned as projects.

Before the 2010 and 2011 Canterbury earthquakes, we undertook a 15-year programme to seismically strengthen our zone and distribution substation buildings. Completed just before the earthquakes, the programme demonstrated immediate benefits for our community, with the reinforced substation buildings sustaining significantly less damage compared to unreinforced ones. All our substation buildings are now considered to have appropriate levels of seismic resilience. We have a number of pole type substations that do not meet current seismic standards. These present a moderate risk and are planned for progressive replacement.

The condition and integrity of substation kiosks can significantly impact switchgear reliability and life, with moisture and pollution contributing to deterioration and failure. Steel kiosks in our eastern suburbs, closer to the sea, are more susceptible to corrosion. We monitor their condition, conducting spot repairs when economic and replacing them when necessary. We now have a stainless-steel design option for use in areas with high corrosion levels when installing or replacing kiosks.

We do not have a formal health model for substation buildings. A building's end-of-life is often dictated by obsolescence where site asset upgrades require a substantially different footprint or significant building modification, and it is not practical to modify the existing building. The Schedule 12a building condition is approximated using a combination of age and identification of buildings with obsolescence factors.

Our building assets are influenced by the effects of climate change such as sea level rise and the potential for increased flooding. We are currently assessing the likely long-term impact of climate change on this asset class and developing appropriate resilience strategies.

7.3.3.2 Reliability

Substation equipment reliability may be compromised by external factors such as vermin, weather related ingress, and unfavourable internal conditions like dampness or excessive heat. In extreme cases, structural failure of the building or structure can also pose a threat. Our inspection, maintenance, and renewal programmes provide us with essential information. This data enables us to strategically plan routine maintenance and renewals, ensuring the reliability of network equipment remains robust.

7.3.3.3 Issues and controls

Table 7.3.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.3.3 Network property issues / controls

Common failure cause	Known issues	Control measures
Third party interference	Unauthorised entry poses a risk to health and safety. As the price of copper rises and in the midst of a cost of living crisis, this has become an escalating issue.	Substation access is controlled through a hierarchical key system, with users assigned access levels based on competencies. Zone substations employ outer boundary barriers like locked gates, fencing, and walls to limit unauthorised entry. Switchyard fencing includes deterrents like tall fencing with electrified top wires or razor/barb wires. Critical sites may also be monitored with security cameras. SCADA monitors switchyard and building doors for "left open" status. Regular inspections include verifying security and entry systems at all substations. We have initiated a community service advertising campaign encouraging the public to dial-in anything they see that is suspicious.
	Lost or stolen substation keys could be used for illegal access.	To enhance zone substation site security, we plan to upgrade access systems with electronic technology.
	Vegetation in and around our assets poses an operational safety hazard.	We conduct scheduled and reactive grounds maintenance programmes.
	Graffiti, which is generally visually unappealing to the public .	Graffiti is managed through a ground maintenance and graffiti removal programme.
Structural and environmental issues	Access is restricted to earthquake prone buildings.	We have finished our seismic strengthening programme, and there are currently no access restrictions due to seismic limitations.
	The presence of asbestos in both Orion and privately owned sites, within the building materials, poses a health risk to our staff and service providers.	We have implemented an asbestos management plan, asbestos registers, and provided training and education. We also have established procedures and Accidental Discovery Processes (ADP).
	Working on contaminated land poses health risks to our service providers and the public, and it can also cause significant harm to the environment.	We have a established procedure for handling work on identified contaminated land, along with an Accidental Discovery Process.
Deterioration	Water-ingress into buildings can damage our assets.	We regularly inspect and maintain buildings, performing tasks like gutter and spouting cleaning, as well as applying waterproofing paints and membranes.
	Old wooden substation doors require more maintenance and are not as secure as newer aluminium doors.	We are progressively replacing wooden doors with aluminium doors.

7.3 Network property continued

7.3.4 Maintenance plan

Our substation monitoring and inspection programmes are listed in Table 7.3.4.

Table 7.3.4 Network property maintenance plan

Maintenance activity	Strategy	Frequency
Zone substation maintenance	Substation Building Condition Assessments to identify substation maintenance requirements.	2 years
Zone substation grounds maintenance	Grounds are adequately maintained; switchyard is free of vegetation and gutters and downpipes are free of any blockages.	Each site is visited once every 3 weeks
Distribution substations	Visual inspection of all the components and recording transformer loading (MDI) value where available. Vegetation issues are also reported and cleared.	6 months
Graffiti removal	We liaise with the local authorities and community groups in our area to assist us with this problem. We also now have in place the Snap Send Solve reporting app and proactive graffiti removal plan where our service providers survey allocated areas of the city and remove offensive graffiti as they find it.	The sites which go through the reporting process are attended usually within 48 hours
Kiosks	Inspection rounds identify maintenance needs. Urban sites undergo grounds maintenance to ensure clear access to kiosks. Rural sites also receive grounds maintenance. We regularly repaint and maintain kiosks, with particular attention to preventing rust in coastal areas.	6 months 2 years As required As required
Substation earthing	We have adopted a risk-based approach for inspecting and testing site earths. Typically, earth systems in our rural areas face more deterioration due to highly resistive soils, stony sub-layers, and corroded earthing systems.	Between 2,000 and 2,600 sites are tested in any year and those sites requiring repairs are scheduled for remedial work in the following year
Roof refurbishment programme	Some of our substation buildings were built with a flat concrete roof covered by a tar-based membrane. These structures are prone to leaks when cracks form in the concrete. To address this issue, we upgrade the buildings by installing a new pitched colour steel roof over the existing one.	Roof replacement is scheduled and prioritised as required, based on survey data

7.3.5 Replacement plan

Certain older high-top kiosks require additional site modifications for replacement with modern counterparts due to their outdated design. Extra funds have been allocated as more of these come up for replacement. Starting from FY28, we have allocated budget to adapt distribution substations and kiosks to mitigate the effects of climate change, especially in locations vulnerable to increased flooding or higher summer temperatures. This will be undertaken alongside a comprehensive review and enhancement of our equipment design standards, ensuring they are well-suited to withstand environmental challenges. Other replacement programmes outlined in our plan include:

- Ongoing replacement of end-of-life substation ancillary equipment, such as battery banks and battery chargers.
- Replacements addressing safety and seismic risk for some older pole substation sites by upgrading the substation design to current standards.
- Upgrading security fencing to meet current standards.
- Targeted replacement of steel kiosks located near the coast due to rust.
- Upgrading access systems to include electronic access and identification to enhance security at zone substation sites.

7.3.5.1 Disposal

We evaluate ownership of property interests, particularly easements on unused sites, and will release ownership as necessary. Procedures for disposal are outlined in Table 7.3.5.

Starting from FY28, we have allocated budget to adapt distribution substations and kiosks to mitigate the effects of climate change, especially in locations vulnerable to increased flooding or higher summer temperatures.

Table 7.3.5 Procedures for disposal

Disposal type	Controls and procedures
Land	Prior to disposing of land, we undertake due diligence investigations on environmental and property matters as considered appropriate
Asbestos	We have guidelines and a management plan for the disposal of asbestos which mandate the appropriate disposal of asbestos as part of our service provider's safe work methods
Contaminated Land	Our substation asset design standards mandate risk assessment for works in and around potentially contaminated land, requiring the use of qualified personnel for advice on disposal options. Disposal requirements and options for all excavation-related work are set outspecified in a network specification.

More than 50% of our subtransmission poles are less than 25 years old and are well within their life expected life span.

7.4 Overhead lines – subtransmission

7.4.1 Summary

Our subtransmission network is the backbone of Orion's service to our customers. It spans 515 kilometers of line supported by 396 towers and 5,507 poles. These are highly critical assets, demanding a high level of reliability, security, and resilience during High Impact, Low Probability (HILP) events.

Due to its critical role, our subtransmission network has the potential to affect a substantial number of customers, compromise safety, and influence the achievement of our asset management objectives.

While our routine inspection and renewal programmes currently maintain the good condition of our subtransmission overhead lines, a portion, mainly in Banks Peninsula, is currently undergoing renewal with some projects in this AMP period.

To prolong the life span of our towers, we are implementing various programmes. These include regular inspections and replacement of hardware and steel components, a painting initiative aimed at extending durability, and a foundation remediation programme.

Our asset management objectives for the subtransmission overhead fleet are:

- Maintain a pole failure rate of less than 1 in 10,000 per year across all voltages – equivalent to a total of nine pole failures on our network per year.
- Achieve targeted levels of system security and performance by promptly responding to unplanned interruptions.
- Monitor and manage the condition of subtransmission assets through routine maintenance and inspections to ensure compliance with industry standards and regulations.
- Extend the operational life of subtransmission assets through proactive maintenance, upgrades, and refurbishments.
- Enhance the resilience of subtransmission assets to withstand and recover from extreme weather events and natural disasters.

7.4.2 Asset description

Our subtransmission overhead lines asset has five components: towers, poles, pole top hardware, tower hardware, and conductors.

7.4.2.1 Towers

Our towers are galvanised steel lattice designs, supported by three different foundation types – concrete footings, direct buried steel grillage, and concrete encased steel grillage. Direct buried steel grillage was predominantly used during the initial construction in the 50s and 60s due to its cost-effectiveness. However, it is susceptible to corrosion, especially near the surface, and may require replacement or remediation, typically by encasing in concrete. The lifespan of towers depends on location, environment, and maintenance. With appropriate maintenance and parts replacement, a tower can have an indefinite life.

7.4.2.2 Poles

Orion uses three pole types: timber, concrete and steel.

Timber poles – preferred for their cost and weight considerations, have historically been our primary choice. Hardwood poles, with superior strength and durability, have an expected life of 45-55 years, but this can vary based on timber species, preservative treatment, and configuration. Timber poles are susceptible to decay, especially near the ground line, requiring periodic inspection and condition-based replacement.

Concrete poles – we use two types of concrete poles – mass reinforced and pre-stressed. Mass reinforced poles are durable but heavy, while pre-stressed poles are lighter and potentially more durable due to improved design and manufacturing processes. The expected life for concrete poles is 80 years.

Steel poles – we have 17 steel monopoles with concrete foundations, designed for site specific strength and height requirements. Steel poles are not widely used because of their higher cost. Their expected design life is 60 years.

Table 7.4.1 summarises our pole fleet by type. Notably, 65% of the pole fleet is timber, requiring periodic below-ground inspection and condition-based replacement. Figure 7.4.1 illustrates the age profile, indicating that more than 50% of our subtransmission poles are less than 25 years old, well within their expected life span.

Table 7.4.1 Subtransmission pole fleet type

Type	Quantity
Hardwood pole	3,676
Softwood pole	441
Concrete pole	1,383
Steel pole	7
Steel tower	396
Total	**5,903**

Figure 7.4.1 Subtransmission support structure age profile

7.4.2.3 Tower hardware

Tower hardware includes insulator assemblies, conductor support clamps or suspension units, and, where installed, vibration dampers. Its condition is crucial as failure can lead to dropping of a conductor which poses significant safety and service level risks. The primary insulators we use are glass disc assemblies and some porcelain disc and polymer post insulators in specific locations. Tower hardware is susceptible to degradation from corrosion, wear due to vibration, and, in the case of insulator strings, failure of insulating material over time.

7.4.2.4 Pole top hardware

Pole top hardware supports the overhead conductors on the pole. It consists of crossarms, insulators, binders, braces, and miscellaneous fixings. The majority of crossarms are constructed of hardwood timber, with the remainder being steel. Hardwood timber crossarms have an expected life of 40 years but are susceptible to deterioration from decay and general environmental weathering. Timber cross arms are also prone to wear at insulator attachment points due to wind and vibration effects on the conductors, as well as general loosening due to timber shrinkage.

Orion undertakes periodic inspection and hardware tightening of timber cross arms. As their life is generally shorter than that of the pole, pole top cross arm assemblies are replaceable. Most poles with timber cross arms require one or more cross arm renewals during their life.

Orion undertakes periodic inspection and hardware tightening of timber cross arms.

Steel cross arms have a longer life, expected to be similar or equal to that of the pole, and are less susceptible to deterioration or wear issues associated with timber arms.

The insulators Orion uses are a mixture of porcelain and glass disc, and composite types. In the case of timber cross arms, insulators and hardware generally have a longer life than the timber arm. They are typically renewed when cross arms are being replaced as it is cheaper and more efficient to do both at the same time.

7.4.2.5 Conductors

The conductor types we use in our subtransmission overhead network are primarily Aluminium Conductor Steel Reinforced (ACSR) and Hard-Drawn copper (HD).

ACSR conductors – are used extensively in our subtransmission network. This conductor is chosen for its high strength and good electrical properties. It performs well under snow, wind, and icing conditions, which are frequently experienced in our region. It generally has a long lifespan in areas not directly exposed to frequent salt pollution. ACSR has an expected life of 55–60 years, depending on the conductor size and operating environment. The predominant cause for end-of-life failure is corrosion due to a combination of water and pollution ingress and its effect on the metals used in ACSR's construction.

HD copper conductors – are used on some of our older subtransmission lines. Due to their cost and the availability of modern alternatives, we now only install them on our LV network when we do replacement works. HD Copper conductors can have a long life but are susceptible to deterioration from annealing due to electrical overloading and corrosion in harsh environments.

For a summary of our sub transmission conductors by type and age profile, see Table 7.4.2 and Figure 7.4.2. We inspect our subtransmission conductor network periodically. Approximately 14% of our subtransmission conductors are more than 55 years old, with some of those to be replaced late in this AMP period.

Table 7.4.2 Subtransmission conductor type

Type	66kV	33kV	
	Length (km)	Length (km)	Total
ACSR	244	205	449
HD copper	29	36	66
Total	**274**	**241**	**515**

Figure 7.4.2 Subtransmission conductor age profile

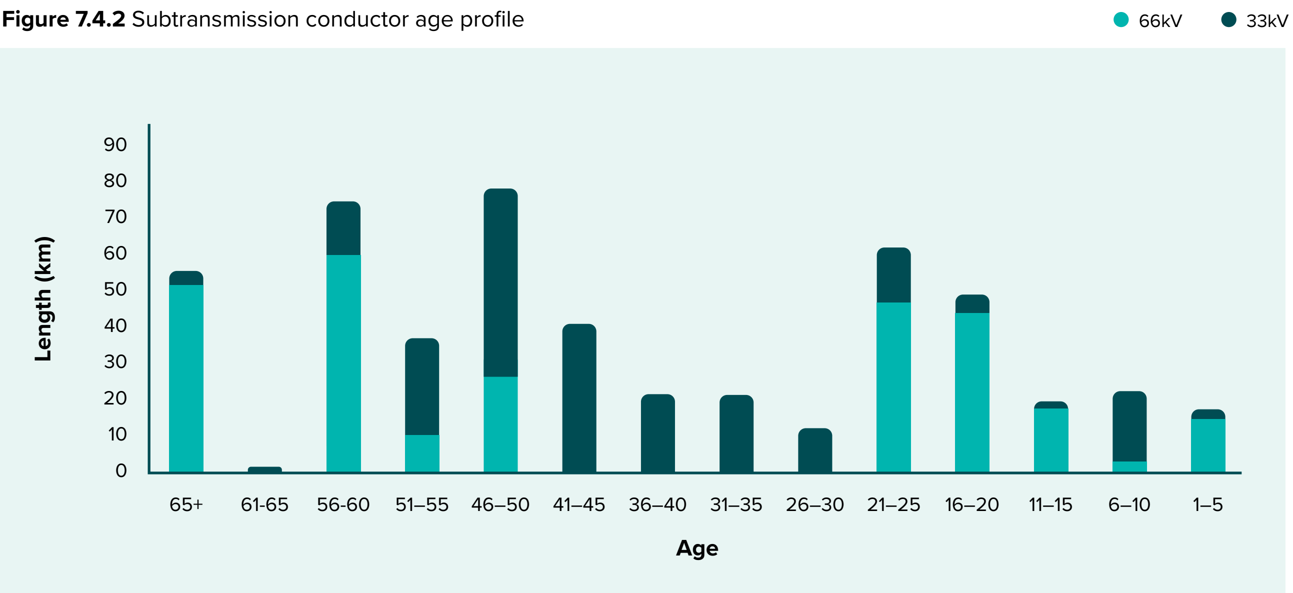


Figure 7.4.2. shows two age groups for 66kV conductors: one centered around 50 years and the other around 20 years. In contrast, the age distribution of our 33kV conductors is more uniform. To assess the remaining lifespan of our 66kV lines, we have conducted core sample analysis. Based on this analysis, one line has been flagged for potential replacement later in the AMP period, as detailed in Section 7.4.5. Overall, the age distribution of our subtransmission conductors does not present a significant concern. We maintain a schedule of periodic inspections to ensure network reliability and safety, further discussed in maintenance Section 7.4.4.

7.4.3 Asset health

7.4.3.1 Condition

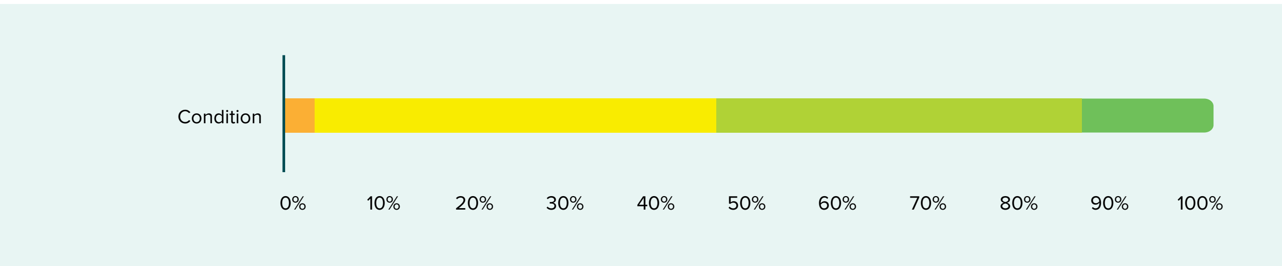
Towers

Most of Orion's towers are at least 50 years old and need routine inspection and maintenance to keep them in good serviceable condition. We have recently developed a health score model for our towers' health based on last visual inspections data which provide condition scores for all tower components. This will be refined in coming years as we collect more inspection data.

The subtransmission tower condition profiles for 330 tower structures that have been inspected are shown in Figure 7.4.3. These scores take into account their upper body, lower body and foundation condition scores.

The remaining 66 towers are due to be inspected in coming years. Towers in H3 and H2 condition have paint or steel replacement work forecasted, depending on the selected strategy for that tower considering the environment location. Tower legs near ground line and foundations also require additional corrosion protection to perform better and we are addressing this through our foundation refurbishment and concrete encasement programme. The condition of our tower grillage foundations below the immediate ground level is currently considered satisfactory and this work will start again later in this AMP period.

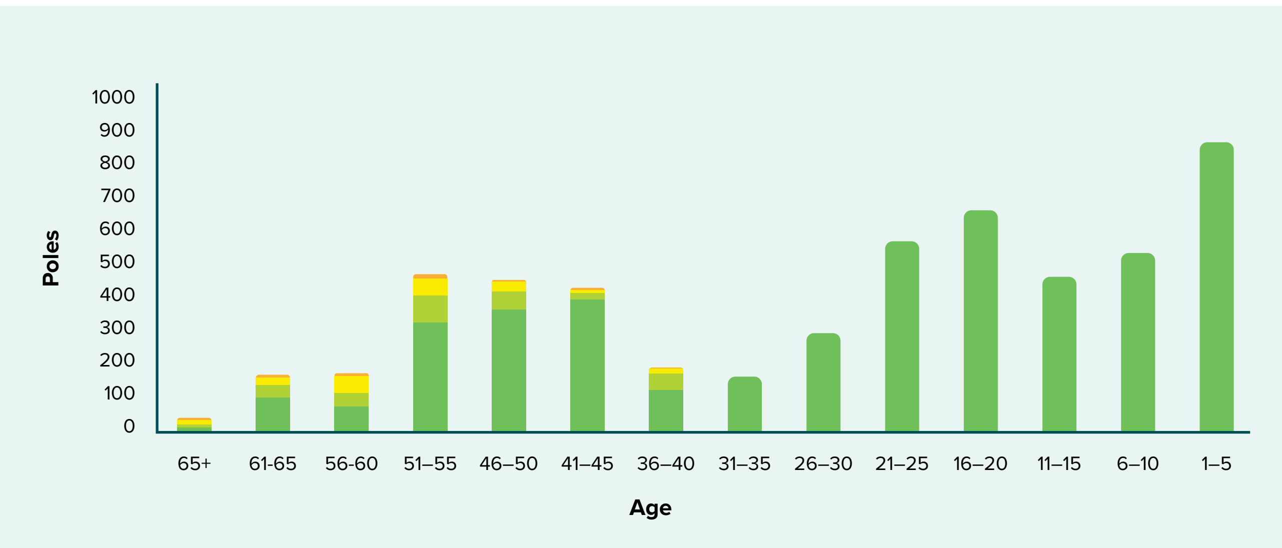
Figure 7.4.3 Subtransmission tower condition profile



Poles

As shown in Figure 7.4.4, the overall condition of most sub transmission poles is good (H4 - H5). More than 50% of our 66kV poles are less than 20 years old, and are in their early lifecycle stage. Most of our 33kV poles are older but still in serviceable condition, with some exhibiting age-related deterioration, primarily in timber poles. These are being prioritised for replacement.

Figure 7.4.4 Subtransmission pole condition profile

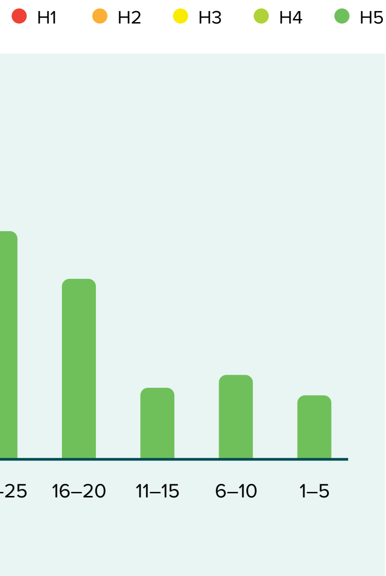


Conductors

The conductors on our overhead subtransmission network are performing well, as shown in Figure 7.4.5. The copper conductors on some 33kV lines are older and exhibiting signs of deterioration, and we are monitoring them during routine inspections.

We have conducted detailed testing on some of our tower line conductors. The Bromley to Heathcote line is in fair condition considering its age and coastal location. We anticipate replacing this conductor and others in FY30 and onwards, but this may be deferred based on the results of testing to assess the rate of deterioration to better determine their end of life.

Figure 7.4.5 Subtransmission conductor condition profile



7.4.3.2 Reliability

Our subtransmission line failure rate currently has been lower than the industry average for the last eight years, see Figure 7.4.6. Our current level of reliability is sufficient and does not require intervention to address remedial performance issues.

Our subtransmission line failure rate has been lower than the industry average for the last seven years.

Figure 7.4.6 Subtransmission line faults per 100km

* Source: PwC Electricity Line Business Information Disclosure Compendium 2016-2023

7.4.3.3 Issues and controls

Table 7.4.3 lists the common causes of overhead line failure and the controls implemented to reduce the likelihood of these failures.

Table 7.4.3 Subtransmission overhead line failure controls

Common failure cause	Known issues	Control measures
Material deterioration	**Timber poles** – lose strength over time due to timber decay. **Conductors** – degrade over time due to fretting, corrosion and fatigue. **Hardware** – binders fatigue, and insulators can fail over time. Wooden crossarms may fail due to decay/rot. On wooden crossarms, insulators may loosen due to vibration-induced wear, timber shrinkage, or timber decay.	Design to AS/ NZS7000-2016 including deterioration allowances. Pole inspection and replacement programme. Conductor visual inspection. Maintenance inspections and re-tightening programme.
Third party interference	**Poles** – third-party civil works may undermine pole foundations, or third parties may damage poles due to impact. **Conductors** – working near power lines can be fatal or lead to serious injury.	Reflective markers are attached to all roadside poles in the rural area. A consent is required to work within 4m of overhead power lines. Signage and media advertising campaign to raise awareness.
	Conductors – clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles or conductors sagging too low.	A High Load Consent is required when transporting loads with an overall height of 4.8 meters and higher along the road corridor. Conductor road crossing heights are inspected and maintained for compliance with NZECP34.
	Conductor – trees in contact with conductors can cause damage to the conductor and heighten the risk of electrocution for anyone coming into contact.	Vegetation control work programme to meet tree regulations. Tree cut notices are sent to tree owners. Public information advertising campaign.
Environmental conditions	**Timber poles** – ground conditions can contribute to timber decay reducing strength. **Conductors** – snow and ice on conductor can cause excessive loads. Lines can clash in high winds leading to conductor damage causing outages. **Hardware** – intense vibrations from laminar flow wind and strong weather can cause fatigue and wear on hardware.	Design in accordance with AS/NZS7000-2016. Maintenance inspection and replacement programme. Conductor sag is addressed through the line re-tightening programme. Hardware retightening programme.

7.4.4 Maintenance plan

Our maintenance activities are listed in Table 7.4.4. Maintenance involves a combination of time-based inspections, preventive maintenance, and condition-based maintenance.

Table 7.4.4 Subtransmission maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Visual inspection of poles and line components for defects.	5 years
Conductor testing	Non-destructive in situ testing. Tower lines have sections of conductor removed and destructively tested.	As required
Subtransmission thermographic survey	Detect localised temperature rise on components which can be due to a potential defect.	2 years
UV corona camera inspection	This technology can detect excessive discharge on line insulators not normally detectable by other means. It is used to locate faults and assess the general condition of insulators.	2 years
Vegetation management	Proactive vegetation management programme to trim trees to meet the requirements of the tree regulations. We also consult with landowners whose trees, while outside of the clearance zone, may present a risk to our assets.	2 years
Retightening / refurbishment programme	Retightening of hardware and the replacement of degraded or problematic components as required, including insulators, dissimilar metal joints, HV fuses, hand binders, and crossarms.	12 – 18 months from new (retighten); 20 years (retighten); 40 years (refurbish)
Tower painting	Condition assessments are carried out during inspections to identify tower maintenance requirements. We monitor the steel condition and undertake further investigation when issues are highlighted. The ongoing painting programme is designed to protect good steel before any issues arise, and the coating systems are then maintained to optimise this protection.	1st paint approx. 35-50 years from new, dependent on environmental factors Repaint approx. 15-20 years depending on condition and location
Tower foundations	Tower foundation maintenance encasing the existing tower legs and where required grillage foundations in concrete. Once this is complete only the above ground interfaces will require ongoing attention.	One off remediation
Tower inspection	Visual and lifting inspections (inspect below conductor fixtures) provides condition assessment of the tower steel, bolts, attachment points, insulators, hardware and conductors	8 years for visual inspection 20 years each circuit (10 years each line) for lifting inspection

7.4.4.1 Light Detection and Ranging trial (LiDAR)

In FY24 we ran a trial of a 'Digital Twin' incorporating Light Detection and Ranging (LiDAR) capture for five of our subtransmission tower circuits. We will build on the encouraging results of the trial to capture a further four of our sub transmission tower circuits. We will model these lines to monitor ground clearances and vegetation clearance violations on an ongoing basis. The results will be compared with our visual condition assessments, climbing inspection and inspections using drones. The aim of the trial is to determine if it is more cost-effective for us to collect more robust data for analysis using this method, which is also safer than asking service providers to climb towers.

The additional four lines we will inspect using LIDAR capture are:

- ISL – SPN = Islington to Springston
- HSL – HTE = Halswell to Heathcote
- HTE – BPK = Heathcote to Barnett Park
- HTE – BRM = Heathcote Bromley

LIDAR inspection of these four remaining lines will complete a model of all Orion 66kV tower lines. We will continue to evaluate the best and most cost effective capture methodology between drones, helicopter or fixed wing aircraft.

We will extend the LiDAR inspection programme to the rest of the subtransmission network, if it proves to be valuable. Future plans to use LiDAR to monitor vegetation and ground clearance violations of the 11kV and LV network are in development.

7.4.5 Replacement plan

Towers

With our planned foundation remediation, painting, and maintenance programmes, we do not foresee any tower replacements being required within this AMP period.

Poles

Our replacement strategy is based on a combination of our risk-based approach where we proactively replace low-health poles in high-criticality locations; and our pole inspection programme where we identify poles to be replaced based on their condition. We have set an asset class objective to achieve a pole failure rate of less than 1 in 10 thousand poles per year. This is equivalent to a total of nine pole failures on our network per year.

To determine our investment requirements for achieving this objective, we analysed two scenarios: one where we take no action, 'do nothing' and the other, 'targeted intervention'.

'Do nothing' is a counterfactual scenario where poles are not proactively replaced, providing us with a measure of the future risk that must be mitigated.

The 'targeted intervention' scenario involves identifying and prioritising poles based on their condition and criticality to achieve a risk profile consistent with our objectives. This is our chosen approach.

Our 'targeted intervention' approach includes maintaining consistent year-to-year replacement rates to balance service provider workload. It also helps to stabilise costs and better manage the community impact of outages and traffic disruption.

Figures 7.4.7 and 7.4.8 show the risk matrix profiles and summarised risk scenarios for our subtransmission poles. These figures compare our current risk profile to a 'do nothing' scenario and the proposed 'targeted intervention' profiles over the next 10 years. They illustrate that taking no action significantly increases the risk of pole failures and affirm the effect of the forecast replacement programme in managing this risk

We have set an asset class objective to achieve a pole failure rate of less than one in ten thousand poles per year.

Figure 7.4.7 Subtransmission pole risk matrix

Current matrix

Asset criticality index (columns); Asset health index (rows)

	C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	6	29	8	43
H3	0	13	151	18	182
H4	0	27	236	31	294
H5	0	945	3430	613	4,988
Total	0	991	3,846	670	5,507

Risk grade definitions

R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

'Do nothing' matrix by Y10

Asset criticality index (columns); Asset health index (rows)

	C4	C3	C2	C1	Total
H1	0	6	29	8	43
H2	0	0	0	0	0
H3	0	40	381	47	468
H4	0	609	2405	404	3,418
H5	0	336	1031	211	1,578
Total	0	991	3,846	670	5,507

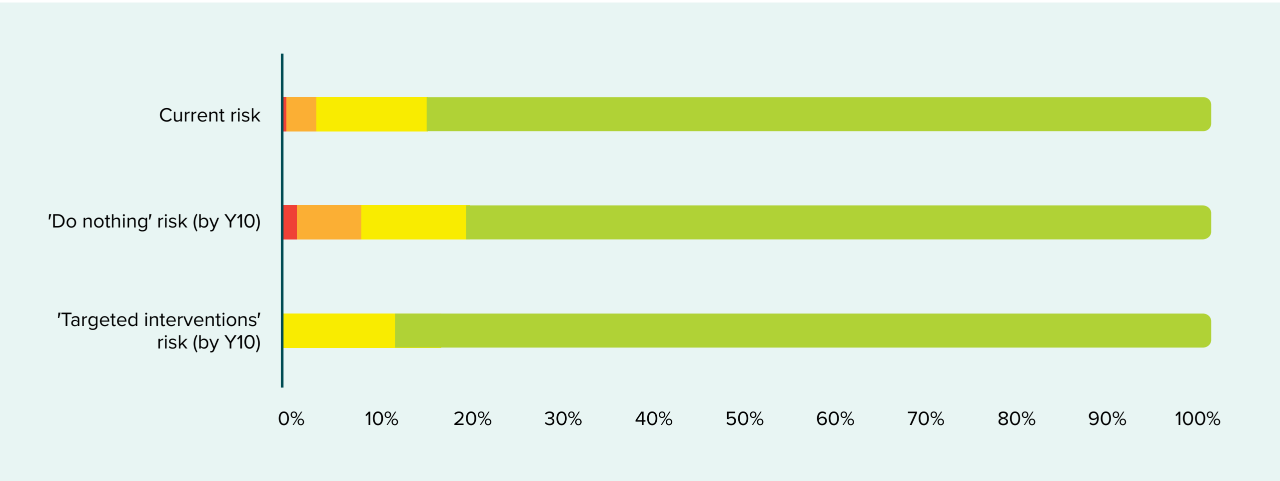
'Targeted intervention' matrix by Y10

Asset criticality index (columns); Asset health index (rows)

	C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	0	0	0	0
H3	0	31	0	0	31
H4	0	609	72	0	681
H5	0	351	3774	670	4,795
Total	0	991	3,846	670	5,507

Figure 7.4.8 Subtransmission pole risk scenarios

R1 R2 R3 R4 R5



Pole top hardware replacement

Crossarms and pole top hardware are primarily replaced based on condition reports from our inspection programme. For economic efficiency, crossarms and insulators are also replaced whenever a pole is replaced. Pole top hardware replacements also occur with the line retightening programme. We may also develop targeted programmes to address poorly performing network sections or to remedy identified problematic type issue components.

Conductors

We have tested conductor samples from our Bromley to Heathcote, Islington to Halswell, and Heathcote to Barnett Park lines to assess their remaining lifespan. Our testing indicates we may need to replace the conductors on our Bromley to Heathcote line within this AMP period. We will retest the Bromley to Heathcote line to evaluate its rate of deterioration. The results will be used to confirm the project timing, and our provisional plan allows for the line to be redesigned in FY27-FY28 and replaced in FY29-FY31.

7.4.5.1 Subtransmission pole refurbishment expenditure

The current risk scenario indicates that a small but significant number of our poles are in the high-risk category, either due to pole condition or circuit criticality. The 'do nothing' scenario illustrates how without investment, the risk will significantly increase over the forecast period.

The escalation of risk is primarily focussed on our Banks Peninsula 33kV subtransmission network, which will soon require refurbishment and, in some cases, upgrades to meet current design standards. The Banks Peninsula network supports local communities, including Diamond Harbour, Little River, Duvauchelle, and Akaroa.

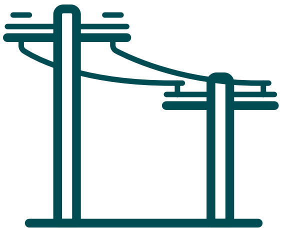
A refurbishment programme focusing on poles, cross arms and hardware is planned over the next 10 years to renew this network. We anticipate that conductors will mostly be in good condition with minimal replacement required. To efficiently manage resource, budgets, and limit disruption to communities we will engage with the people impacted over the next year and maintain engagement throughout the whole project.

Our testing indicates we may need to replace the conductors on our Bromley to Heathcote line within this AMP period.

Supply chain issues, inflation, and increased safety and traffic management requirements have caused our costs to increase substantially above our historical inflation-adjusted levels affecting the accuracy of our financial forecasts. To address this, we now use estimates developed by our cost engineer that more accurately reflect the cost drivers for our programmes.

7.4.5.2 Disposal

Poles are disposed of by our service providers in a manner appropriate to the pole type. A lifecycle analysis carried out in 2020 confirmed that recycling of poles for another use is the best outcome – where possible in non-structural community projects. Examples of where our old poles have been re-used include playgrounds and mountain bike tracks. Poles may be recycled, sold as scrap, on sold for non-commercial purposes or disposed of in landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).



Our 11kV distribution overhead system has 3,143km of lines servicing central Canterbury, Banks Peninsula and outer areas of Christchurch city.

7.5 Overhead lines – distribution 11kV

7.5.1 Summary

Our 11kV overhead lines are the workhorse of our distribution network in rural regions and outer Christchurch city. Any failure of these lines has the potential to negatively impact our safety objectives and disrupt the lives of the community. We are increasing expenditure on our 11kV lines over the next 10 years, primarily to obtain information on the condition of our conductor and reduce pole failures. This investment is also aimed at maintaining overall reliability and asset condition. The increased expenditure will also help us to ensure our network is built to withstand the impacts of climate change.

Our asset management objectives for the 11kV overhead fleet are:

- Maintain a pole failure rate of less than 1 in 10,000 per year across all voltages – equivalent to a total of nine pole failures on our network per year.
- Maintain the resilience of our 11kV lines to withstand weather events and natural disaster.
- Provide greater reliability for our rural network.
- Prevent failures that could result in harm to persons or property.
- Provide service levels at the lowest lifecycle cost.

7.5.2 Asset description

Our 11kV distribution overhead system includes more than 3,100km of lines servicing the rural area of central Canterbury, Banks Peninsula, and outer areas of Christchurch city. These lines are supported by 47,000 timber and concrete poles, some of which also support subtransmission and low voltage conductors.

Our 11kV lines are supplied from our zone substations and Transpower GXPs at Coleridge, Castle Hill and Arthur's Pass. We also have more than 100km of Single Wire Earth Return (SWER) lines used to supply power to remote areas on Banks Peninsula. The 11kV system includes lines on private property that serve individual customers. The 11kV overhead asset class comprises three distinct asset categories: poles, pole top hardware and conductors.

7.5.2.1 Poles

Poles provide structural support for conductors and pole-mounted equipment such as transformers, switches and reclosers. There are four types of poles used on our 11kV network:

- **Timber** – hardwood and softwood types. Hardwood has superior strength over softwood poles due to its dense fibre characteristics. The expected life of hardwood poles depends on the timber species, preservative treatment and configuration. Timber poles in areas exposed to harsh environmental conditions have a reduced nominal service life. The life of softwood poles is highly dependent on the quality of the timber and preservative treatment and is generally shorter than for hardwood poles. Hardwood poles are imported and are becoming difficult to source in larger quantities, whereas softwood poles are grown and manufactured locally and have good availability.
- **Concrete** – precast and prestressed are the two types of concrete poles we use. Prestressed poles exhibit superior strength and are lighter in weight compared to precast types. We no longer install precast poles on our network as they are now considered obsolete and are no longer manufactured. However, precast types exhibit good life and strength characteristics.
- **Steel** – steel poles are used in special circumstances where engineering requirements can not be economically met by timber or concrete types. We currently have four steel monopoles at distribution voltages specifically designed to suit their location and span length. We have installed concrete pile foundations to support these poles.
- **Steel pile** – we have steel pile structures supporting hardwood poles in or near riverbeds.

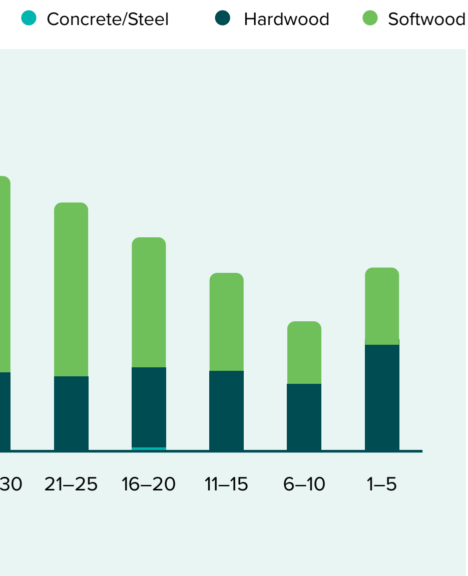
Today, we predominantly install sustainable timber poles due to their dynamic loading characteristics, which make them more resilient to snow, ice and other dynamic loads. Their embodied carbon also has sustainability benefits. Table 7.5.1 shows the pole types and quantities installed on our network.

Table 7.5.1 11kV pole quantities by type

Pole type	Quantity
Hardwood pole	13,990
Softwood pole	16,279
Concrete pole	16,871
Steel pole and piles	51
Total	**47,191**

Figure 7.5.1 shows the transition in the 1990s from concrete poles to softwood timber poles. This change was made based on a combination of lifecycle economics and engineering considerations, particularly to increase resilience to heavy snow events. The age profile shows most of our older poles are concrete. We also have a significant population of ageing hardwood poles which require close inspection and maintenance to maintain their safety and performance.

Figure 7.5.1 11kV pole age profile



7.5.2.2 Pole top hardware

Pole top hardware refers to the components used to support overhead conductors on the pole. It consists of crossarms and braces, insulators, binders and miscellaneous fixings.

Crossarms are constructed from either hardwood timber or steel. We predominantly use hardwood timber crossarms with an expected life of 40 years. Insulators are mostly porcelain, with some glass and polymer types installed. We do not record pole top assemblies or components as discrete assets in our systems and so do not have complete records of the types and ages of these components. Not having this data limits our available asset management strategies to a predominantly inspect and replace on condition approach.

7.5.2.3 Conductors

We use a variety of conductor types for our 11kV overhead network. Which conductor type we use is influenced by historical trends driven by engineering and economic considerations, the terrain and loading requirements, environmental and performance factors.

The conductor types are:

- **Hard Drawn Copper –** are no longer installed on our 11kV network mainly due to economic considerations.
- **Aluminium Conductor Steel Reinforced (ACSR) –** a stranded aluminium conductor with a steel core to provide strength has been used extensively on our HV network. This conductor provides high strength good conductivity and lower cost when compared to copper. It is particularly suitable for rural network applications with long conductor spans. It performs well in snow, wind and ice environments.

- **Aluminium Conductors (AAC) –** are made up of stranded aluminium alloy. All Aluminium Alloy Conductors (AAAC) have a better strength to weight ratio than AAC and offer improved electrical properties and corrosion resistance. The current industry trend is towards increased use of AAAC conductors.

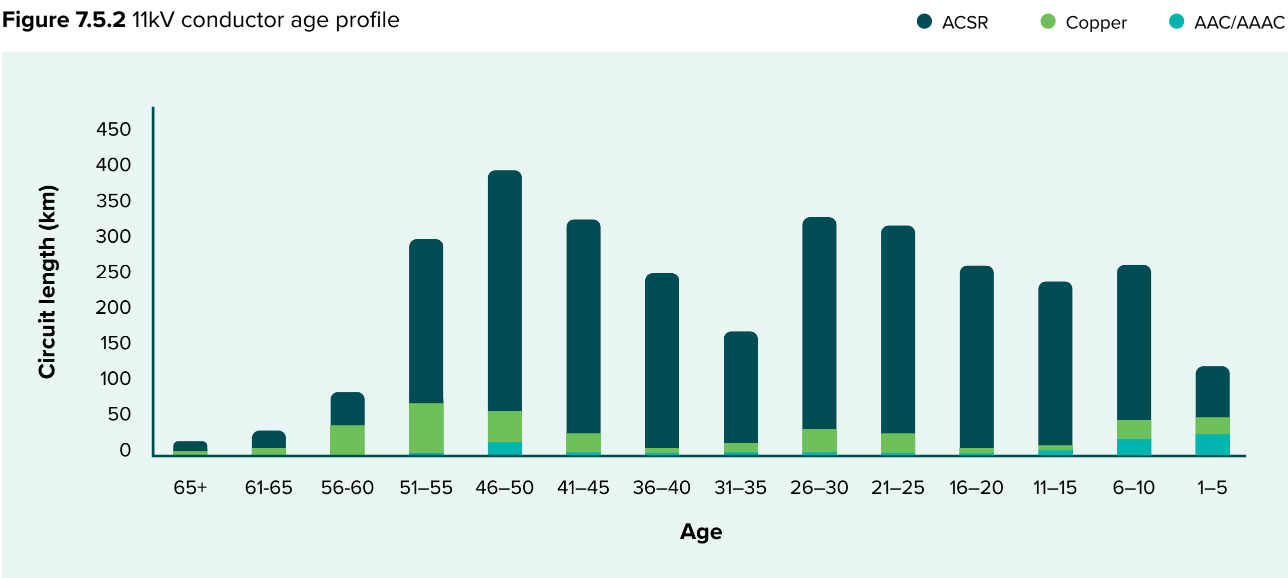
The quantity of conductors in service by broad type is listed in Table 7.5.2.

Table 7.5.2 11kV conductor quantities by type

Conductor type	Length (km)
Copper	330
Aluminium (ACSR)	2,698
Other Aluminium (AAC & AAAC)	115
Total	**3,143**

The age profile in Figure 7.5.2 shows that our conductor population is predominantly ACSR, with copper the second most prevalent conductor type.

Figure 7.5.2 11kV conductor age profile



7.5.3 Asset Health

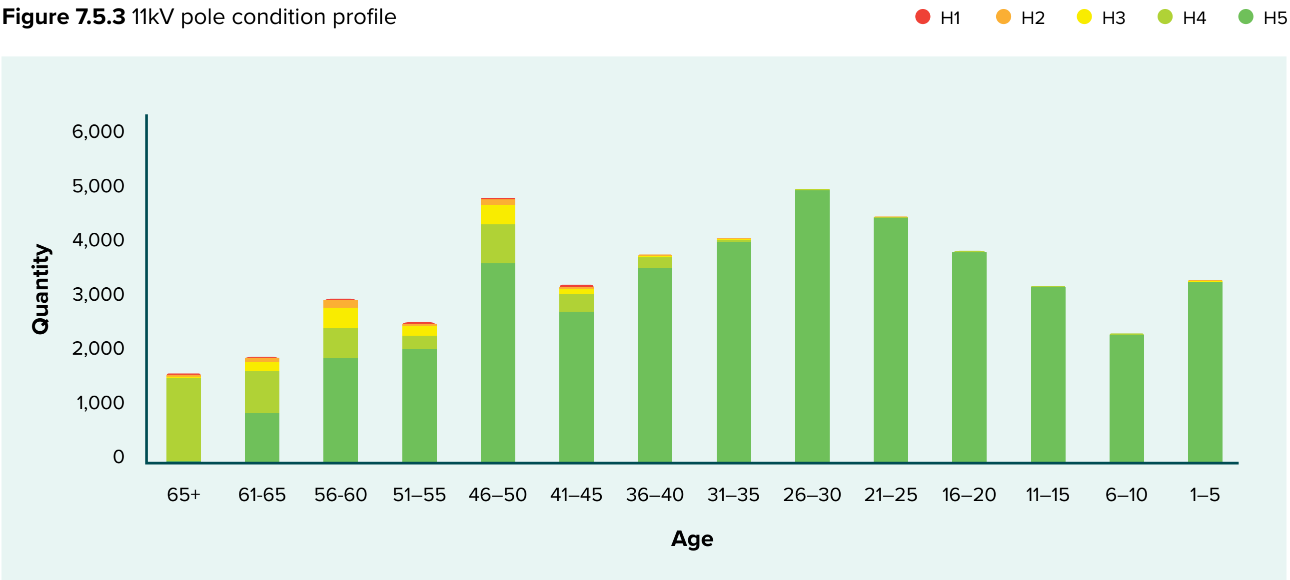
7.5.3.1 Condition

Poles

The condition of our 11kV network has been modelled using Condition Based Risk Management (CBRM) process. Figure 7.5.3 shows the current age and condition profile for our overhead 11kV poles. Our poles predominantly have good health indicators with only a small proportion of the network requiring consideration for renewal.

Our poles predominantly have good health indicators with only a small proportion of the network requiring consideration for renewal.

Figure 7.5.3 11kV pole condition profile



Conductors

Across our wide range of conductor types and ages, we have identified several poorer-performing conductor types. A replacement programme has targeted the older small sized copper conductors.

7.5.3.2 Reliability

The 11kV line faults per 100km line set out in Figure 7.5.4 is compiled using information disclosure data. It shows our 11kV lines fault rate per 100km is consistent with the industry average but has exceeded our target of 18 faults per 100km. The higher than target overhead fault rate is due to a combination of wildlife, vegetation and lightning strike which are factors not directly related to the condition of the asset.

Lightning strikes

We have seen a significant increase in lightning strikes in recent years, particularly in spring and summer with warmer temperatures. These occur sporadically, mainly in rural and Banks Peninsula areas.

Wildlife

Over the last four years we seen an increase in possums coming into contact with our overhead lines. Orion has been installing possum guards on concrete poles that have had significant outage issues. We have also partnered with the Department of Conservation to help eradicate possums in our most affected areas in Banks Peninsula.

Vegetation

Although we have an extensive vegetation management programme some tree species grow faster than our regular tree trimming rounds. We work with landowners to manage their trees. We have also initiated a project to target areas with fast-growing vegetation issues.

While Figure 7.7.1 shows the number of faults is increasing, our SAIDI and SAIFI is improving. This is likely to be a result of installing remote line switches on our network, enabling faster switching and network restoration in response to faults. For more information on vegetation management, see Section 7.7.

Figure 7.5.4 11kV line faults per 100km

Pole failure rate

To support public safety and network reliability we have established a pole failure rate target of less than one failure per 10,000 of all pole voltage classes combined per year. In 2016 we established a more robust definition of 'pole failure' where the pole has failed to be self-supporting under normal load conditions and has fallen or is sufficiently unstable that it is posing a risk to people's safety or damage to property. The term does not cover events where a pole has fallen due to an 'assisted failure', such as impacts from vehicles or trees. It also does not cover 'red tag' poles that are replaced immediately when found to be at risk of failure under normal structural loads.

Following our implementation of that definition, along with a renewed approach to identifying and reporting suspect poles, five years of comparable data has been gathered under this benchmark. Figure 7.5.5 shows we met our asset class objective for the previous five years.

Figure 7.5.5 Pole failure rate (all voltage classes)

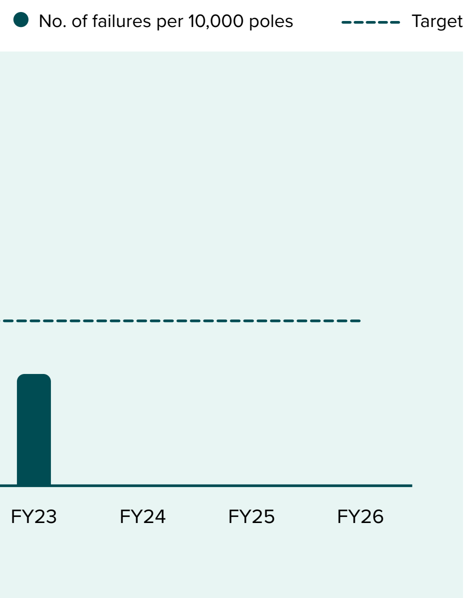


Table 7.5.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.5.3 11kV overhead line failure controls

Common failure cause	Known issues	Control measures
Material deterioration	**Pole** – loss of strength over time due to timber decay. **Conductor** – fretting, corrosion, fatigue. **Hardware** – binders fatigue and insulators fail over time. Wooden crossarms can fail due to decay/rot. Insulators on wooden poles may loosen due to shrinkage.	Robust design standards exceed AS/NZS7000–2016. Pole inspection programme and replacement programme. Conductor visual inspection. Maintenance inspections and re-tightening programme.
Environmental conditions	**Pole** – poor ground conditions can contribute to wooden pole structure decay. **Conductor** – snow and ice loads on conductor can cause excessive sagging. Lines can clash in high winds leading to conductor damage causing outages. **Hardware** – intense vibrations from earthquakes and weather can cause stress on insulators.	Robust design standards exceed AS/NZS7000–2016. Maintenance inspection (including corona camera inspection) and replacement programme. Conductor sag is addressed through the line re–tightening programmes and reduces lines clashing.
Third party interference	**Pole** – third party civil works has the potential to undermine pole foundations.	We have a Close Approach consent process and measures for temporary pole stabilisation (NZECP34).
	Vehicles vs poles	Reflective markers are attached to all roadside poles in rural areas.
	Conductor – working near power lines can be fatal or lead to severe injury. **Conductor** – clearance from the road surface may change over time because of road re-surfacing, vehicle contact with poles or soil disturbances caused by nature. **Conductor** – tress in contact with conductors can damage the conductor and heighten the risk of electrocution to anyone coming into contact with them or environmental impacts.	A Close Approach Consent is required to work within 4m of overhead power lines. Signage and public information advertising campaign to raise awareness. A High Load Consent is required when transporting loads with an overall height of 4.38 metres and higher along the road corridor. Conductor height inspected and maintained for compliance (NZECP34). Tree regulations. Vegetation control work programme. Tree cut notices are sent to tree owners. Public information advertising campaign.

7.5.4 Maintenance plan

To ensure the safe and reliable operation of our network, our maintenance strategy is to conduct regular condition inspections and replace components as required. We also schedule planned preventive maintenance, including re-tightening, to address loosening and damage after approximately 20 years, depending on circuit criticality. This supports Orion's asset class objectives to maintain our overhead network performance in balance with risk and cost to meet customer expectations.

Currently, we have limited accurate condition data on our overhead conductors, which hinders our ability to make decisions about conductor renewal and potential future climate adaptation renewal programmes. We will trial a new conductor inspection process in FY25 and refine it over the next few years. For our maintenance activities, see Table 7.5.4.

Table 7.5.4 11kV overhead maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Detailed inspection of poles and lines including excavation for at risk wood poles.	Five years.
UV corona camera inspection	Detect excessive discharge on line insulators not normally detectable by other means. It is used to locate faults and assess the general condition of insulators.	Two years.
Retightening / refurbishment programme	Retightening of hardware components, replacement of problematic assets if required e.g. insulators, dissimilar metal joints, HV fuses, hand binders and crossarms.	Initially at 12 – 18 months from new (retighten), then at 20 years (retighten/refurbishment), then again at 40 years (refurbishment).

7.5.5 Replacement plan

7.5.5.1 Poles

As a pole's condition declines, its probability of failure, defects, and condition-driven failures increase. To meet our asset class objective of maintaining a pole failure rate of less than one in 10,000 poles and to reduce our faults per km rate, we have considered these options:

- **Do nothing –** a counterfactual alternative where only reactive replacements are done for comparison of potential future risk
- **Targeted intervention –** prioritising replacements based on condition and criticality
- **Underground conversion –** replacing overhead lines with an alternative asset

The optimised replacement approach options are shown in Figures 7.5.6 and 7.5.7. As mentioned in Section 6.3, we have produced a risk matrix for our poles fleet based on the EEA Asset Criticality Guide. Below is an example of our current, 'do nothing,' and 'targeted intervention' risk profile over the next 10 years. It shows that if we do nothing, we would expect to see a substantial increase in the number of in-service pole failures.

Figure 7.5.6 11kV pole risk matrix

Current matrix

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	0	62	9	0	71
H2	3	325	57	2	387
H3	22	992	199	1	1,214
H4	52	3977	331	4	4,364
H5	520	38193	2367	75	41,155
Total	597	43,549	2,963	82	47,191

Risk grade definitions

R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

'Do nothing' matrix by Y10

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	3	387	66	2	458
H2	0	3	0	0	3
H3	73	4953	529	5	5,560
H4	482	32539	1934	58	35,013
H5	39	5667	434	17	6,157
Total	597	43,549	2,963	82	47,191

'Targeted intervention' matrix by Y10

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	2	0	0	0	2
H2	0	3	0	0	3
H3	73	3193	1	0	3,267
H4	482	32539	854	0	33,875
H5	40	7814	2108	82	10,044
Total	597	43,549	2,963	82	47,191

Figure 7.5.7 11kV pole risk scenarios

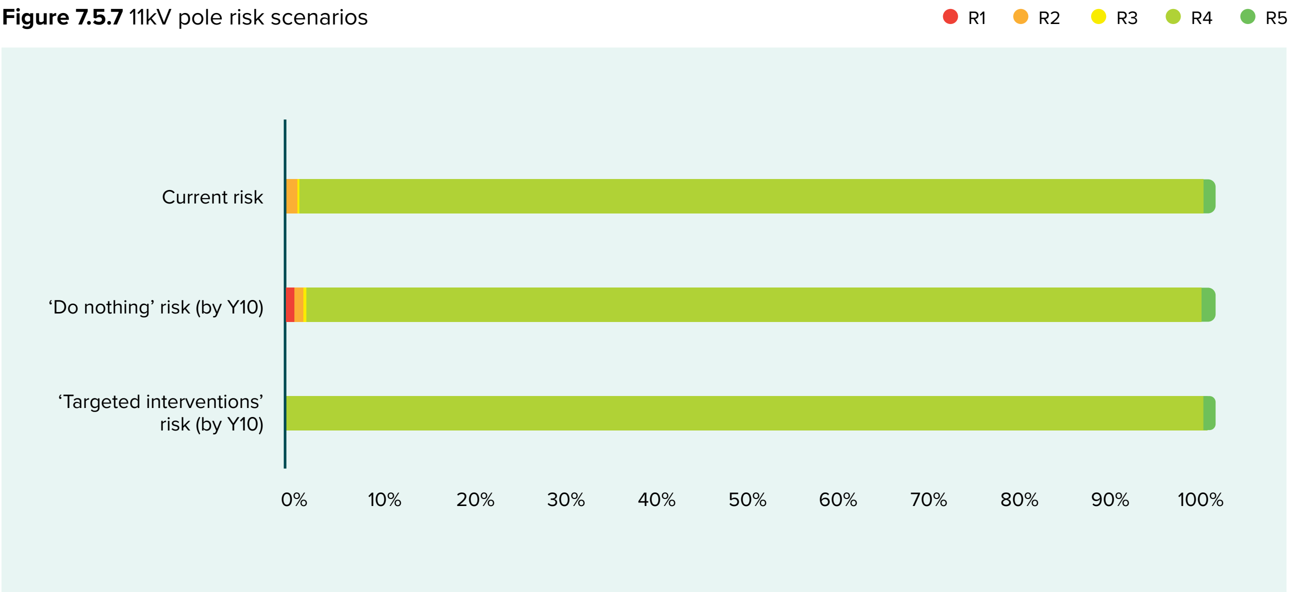
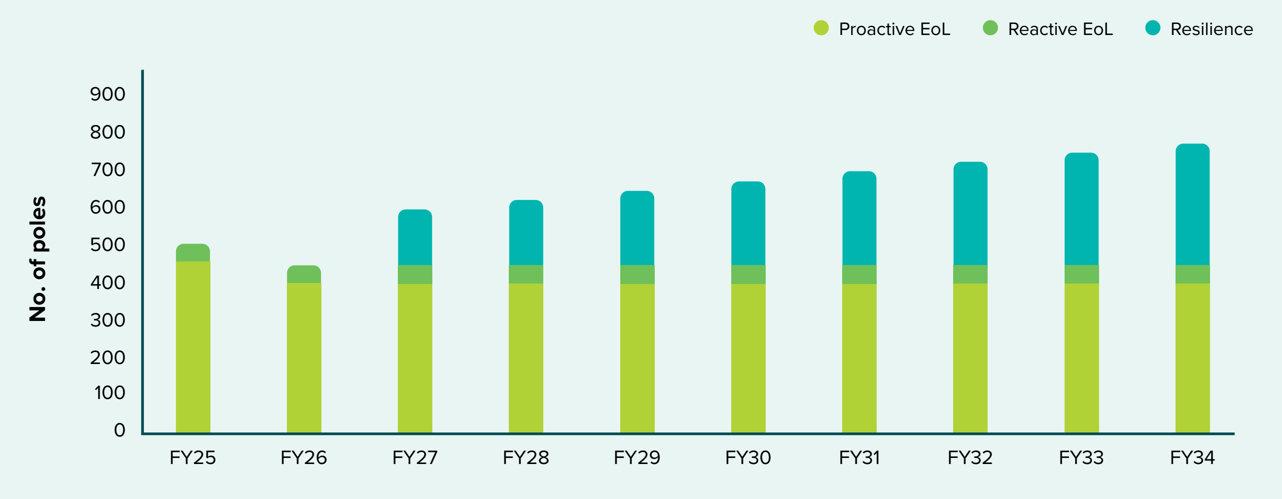


Figure 7.5.8 illustrates our planned gradual increase in 11kV pole replacements.

Figure 7.5.8 11kV pole replacement plan



We have significantly scaled back our planned replacement numbers for both 11kV and 400V poles compared to our previous forecasts. This reduction is due to the condition data from our enhanced pole inspection process, which has given us much greater confidence in the condition of our pole fleet, exceeding our initial expectations.

Given that the overhead network faces high susceptibility to the physical risks associated with climate change, we plan to replace approximately 4,000 poles in high wind zones over the next decade. Our preliminary analysis indicates these poles carry potentially greater risk due to their construction and design standards potentially falling short of future environmental conditions influenced by climate change.

In total, we are projecting an average of 1,500 poles to be replaced annually over the next 10 years. This marks a significant increase from our current delivery rates. We will collaborate closely with our service providers to ensure an adequate pipeline of field crews to undertake the workload. For more details, see Section 9 on how we deliver.

7.5.5.1 Improved pole inspection process

Orion's greatest asset risk to reliability and public safety is from our overhead network, which is vulnerable to adverse weather conditions. This network is largely situated in road reserve areas, posing public safety risks in case of failure. To address the risk of pole failure, we investigate any incidents, utilising the information gained to enhance our management processes. Critical to risk mitigation is the thorough inspection of poles, enabling informed decisions on replacements before failure occurs.

Our examination of our inspection process in FY21 identified key improvement opportunities in the existing visual inspection method:

- lacked repeatability
- failed to accurately detect the most common wooden pole failure mode – decay below ground level
- did not provide us with sufficient details about a pole's condition and defects for planning and forecasting

Given that the overhead network faces high susceptibility to the physical risks associated with climate change, we plan to replace approximately 4,000 poles in high wind zones over the next decade.

Introduced in 2021, the most impactful change in our new pole inspection process involved introducing excavation for poles at a higher risk of below-ground decay. We specifically targeted the 12,700 untreated hardwood and softwood larch poles in our network. Under the new process, we excavate to a maximum depth of 300mm in sealed pavement, asphalt, and grass to inspect the underground conditions of these poles. Any necessary reinstatement promptly follows.

Since initiating excavations in April 2021, we have significantly reduced the number of high-risk poles on our network. To make the process more efficient, we customised a digital field capture platform for recording pole inspection data, facilitating prompt assessment by our engineers.

This platform empowers field service providers to capture photos and annotate them, aiding decision-making in defect assessments and pole replacements. These photos serve as historical references to measure deterioration rates during subsequent inspections.

Our accelerated implementation of the new pole inspection process has shifted our focus from planned pole replacements to an increased emphasis on replacing previously undetected high risk poles. While the new inspection process provides Orion with higher-quality data, it does require pole inspectors to spend more time on each inspection, due to the excavation needed at the base of some poles and the collection of comprehensive condition information. This has resulted in a rise in expenditure for pole inspections.

Despite the increased upfront costs, we anticipate the long-term benefits will enable us to make more accurate forecasts and better planning decisions for future pole replacements. The flow-on effect of this is expected to be a reduction in reactive works and reduced related costs.

7.5.5.2 Pole top hardware

For economic efficiency, crossarms and insulators are replaced in conjunction with the pole replacement programme, the line retightening programme, and targeted programmes if necessary. Recently, we have been prioritising reliability improvement for rural townships by targeting feeders through a combination of insulator and crossarm replacements, along with the installation of automated line switches.

7.5.5.3 Conductors

We are moving to increased standardisation of our conductor fleet to improve our lifecycle economics and repairability. Unless capacity considerations dictate otherwise, our preferred conductors will be either ACSR Dog for larger capacities or ACSR Flounder for smaller rural circuits. We will gather more condition assessment data, and based on that information, we will develop a new replacement programme for aging conductors in the coming years. Our forecast for the current AMP period includes the budget to replace the identified conductors through our new inspection programme.

As part of Orion's asset management strategy, we are developing an adaptation plan to address the potential physical risks posed by climate change to our network.

7.5.5.4 Overhead to underground conversion

One option for replacing end of life 11kV overhead lines is converting to underground cables. As the cost per meter is significantly lower for overhead lines it is normally not economically justifiable to do so. However, we are considering a programme from FY27 onwards to convert approximately 4km of overhead lines to underground in the western suburbs of Christchurch per year. The drivers for this replacement are a mixture of condition-based replacement, safety, resilience and reliability improvement. A business case including cost benefit analysis will be completed to assess the viability of this project.

7.5.5.5 Disposal

Our pole disposal approach is consistent across voltage classes, see Section 7.4.5.2.

Since initiating excavations in April 2021, we have significantly reduced the number of high-risk poles on our network.

Our 400V low voltage distribution overhead network is 2,337km of lines mainly within Region A, delivering power from the street to customer's premises.

7.6 Overhead lines – distribution 400V

7.6.1 Summary

Our 400V low voltage distribution overhead network spans 2,337 km of lines, primarily within Region A, delivering power to our customers' premises. The lines are supported by timber, concrete, and steel poles. To address our aging pole population, meet performance standards, and prepare our network for the increasing adoption of Distributed Energy Resources (DER) technology by customers, we are increasing our pole and conductor replacement rate and expenditure over the AMP period.

Our objectives for this asset class are:

- Maintain a pole failure rate of less than 1 in 10,000 per year across all voltages – equivalent to a total of nine pole failures on our network per year.
- Provide greater reliability and resilience
- Reduce the incidence of failures with the potential to cause harm to persons or property

7.6.2 Asset description

The low voltage overhead asset has three distinct component groups: poles, pole top hardware and conductors.

7.6.2.1 Poles

There are three types of poles on our low voltage network: timber, concrete, and steel. The characteristics of these pole types are described in Section 7.5.2.1. Many of our older timber poles have estimated ages, as no installation or manufacture date was recorded or available before the adoption of our information systems around the year 2000. The new pole inspection process introduced in FY21 will address this within five years by collecting pole manufacture date information where it is marked on the pole. Table 7.6.1 shows the pole type and quantities on our network.

Table 7.6.1 400V pole quantities by type

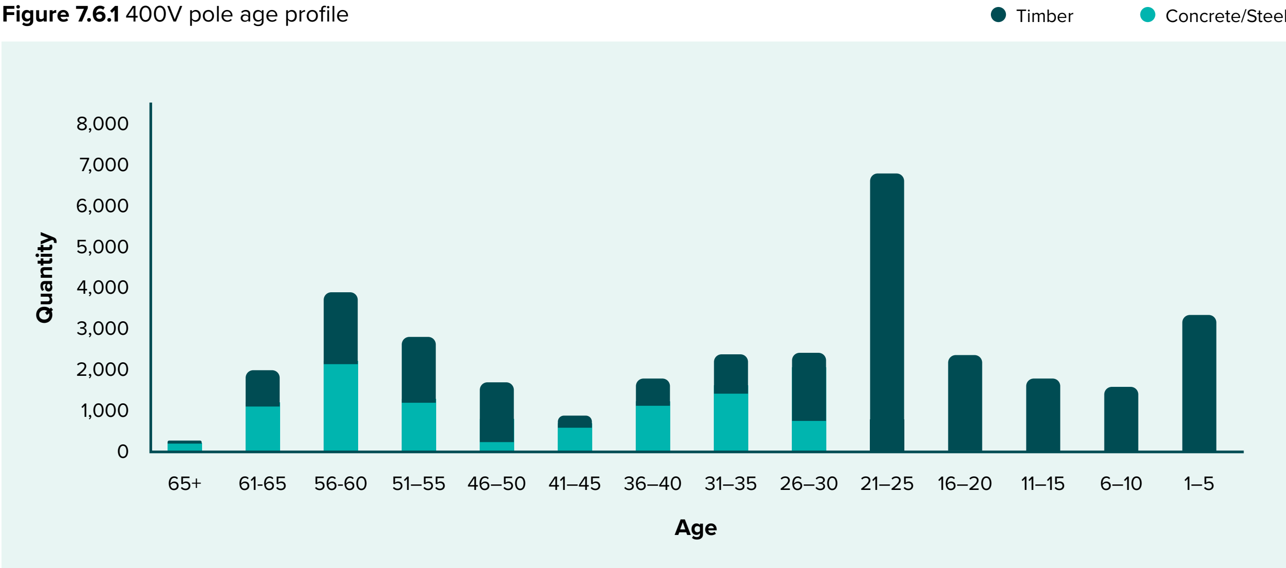
Pole type	Quantity
Hardwood pole	9,855
Softwood pole	15,529
Concrete pole	8,872
Steel pole	3
Total	**34,259**

7.6 Overhead lines – distribution 400V continued

Figure 7.6.1 shows the known age profile for our low voltage pole population. It illustrates that our older poles are a mix of timber and concrete types. The age profile indicates a transition in the 1990s from concrete pole types to timber pole types, driven by a combination of lifecycle economics and engineering considerations.

The age profile also reveals a spike in poles aged between 21 and 25 years, associated with pole replacements that occurred during the installation of a telecommunications network on our poles.

Figure 7.6.1 400V pole age profile



7.6.2.2 Pole top hardware

Pole top hardware comprises components used to attach the overhead conductor to the pole. This includes crossarms and braces, insulators, binders, and miscellaneous fixings. We utilise hardwood timber crossarms with a nominal asset life of 40 years. Porcelain insulators are installed on our network, and we collect data on the condition of pole top hardware, recording the age and type for new insulators.

7.6.2.3 Conductors

We use a variety of mainly covered conductor types for the low voltage overhead network. The conductor type chosen is influenced by cost considerations, asset location, environmental and performance factors. The different conductor categories are listed in Table 7.6.2.

Table 7.6.2 Low voltage conductor quantities by type

Conductor type	Length (km)
Copper (Cu)	785
Aluminium (Al)	147
Unknown	511
Streetlighting (Cu)	894
Total	**2,337***

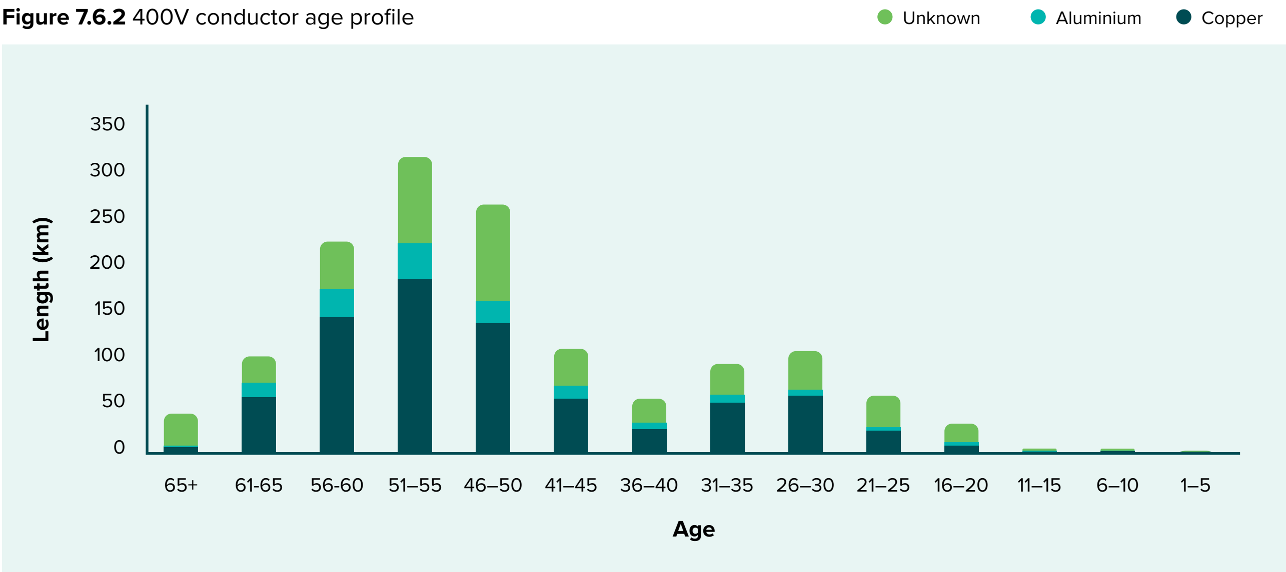
* Total figure excludes adjustment for road crossings and back section lines.

7.6 Overhead lines – distribution 400V continued

The age profile in Figure 7.6.2 shows the majority of our conductors are greater than 40 years old. Our conductor population is predominantly copper, with a large proportion where the type is unknown. Our operators are tasked with identifying the unknown conductor where possible.

Only a relatively small number are recorded as aluminium. It is important for us to determine the size and type of our low voltage conductors so that we can determine the capacity of our low voltage network.

Figure 7.6.2 400V conductor age profile



7.6.3 Asset health

7.6.3.1 Condition

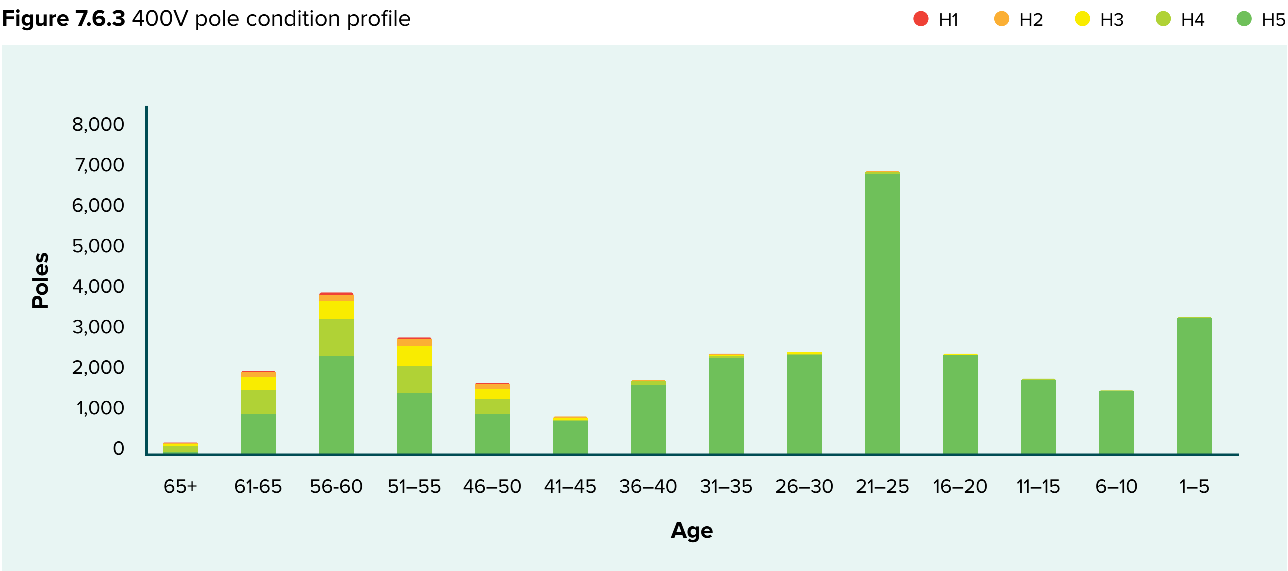
Poles

The condition of our low voltage poles has been modelled using the Condition Based Risk Management (CBRM) process. Figure 7.6.3 illustrates the condition profile for our low voltage poles. The pole population is predominantly in a serviceable condition, however a substantial number of older poles are approaching the end of their life with health indicator grades H2 and H3 and will likely require replacement within this AMP period.

Conductors

Our low voltage conductors are predominantly PVC covered with typically shorter spans and low tensions of about 5% of Conductor Breaking Load. We do not currently have a routine inspection programme for 400V conductors and condition has historically been based on the type of issues experienced and their age. We are creating a program to inspect our 400V lines over the AMP period to improve our condition information.

Figure 7.6.3 400V pole condition profile



7.6.3.2 Reliability

We are not required to record SAIDI or SAIFI for our low voltage network. However, to ensure prudent asset management we collect performance data on our low voltage system. The level of defective equipment has been trending downwards over the last four years.

Historically some events categorised as weather may have been caused by vegetation from outside of the required clearance zone. We will continue to improve the distinction between weather and vegetation related faults to identify areas with vegetation issues to be addressed. Third party related incidents are slowly trending upwards. The majority of these are due to contractor vehicles and excavators contacting overhead lines.

7.6.3.3 Issues and controls

The controls for reducing the likelihood of failure for our low voltage overhead asset are the same as for our 11kV overhead assets, see Table 7.5.3.

7.6.4 Maintenance plan

Regular inspections are carried out to ensure safe and reliable operation of our assets. Our maintenance activities are driven by a combination of time-based inspections and on condition repair or replacement.

7.6.5 Replacement plan

7.6.5.1 Poles

In recent years, our replacement rate for low voltage poles has been moderately low. This was partly due to a significant investment in pole replacement in 2000 and 2001 associated with a telecommunications network rollout, which substantially improved the condition of our low voltage poles. The buffer created by this investment has now diminished. To maintain a low failure rate and ensure the safety of our low voltage poles, we plan to increase our replacement rate over this AMP period.

As discussed in Section 6.3, we have developed a risk matrix for our pole fleet based on the EEA Asset Criticality Guide. Below is an example of our current, 'do nothing', and 'targeted intervention' risk profile over the next 10 years. It illustrates that if we take no action, we can anticipate an increase in the number of unserviceable poles and a corresponding rise in the failure rate.

Figure 7.6.4 400V pole risk matrix

Current matrix

Asset criticality index

Asset health index	C4	C3	C2	C1	Total
H1	40	97	0	0	137
H2	209	345	0	0	554
H3	428	1094	0	0	1,522
H4	722	2067	8	0	2,797
H5	7137	21890	222	0	29,249
Total	8,536	25,493	230	0	34,259

Risk grade definitions

R5	Low relative consequence of failure. Tolerating increased failure rates or running asset to failure may be viable strategies
R4	Typical asset in useful life phase. Strategy is to monitor and maintain
R3	Healthy but highly critical assets. Operating context would need to be changed if consequence of failure are to be reduced
R2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be scheduled
R1	Combination of high consequences of failure and reduced health indicates high risk. Immediate intervention required

'Do nothing' matrix by Y10

Asset criticality index

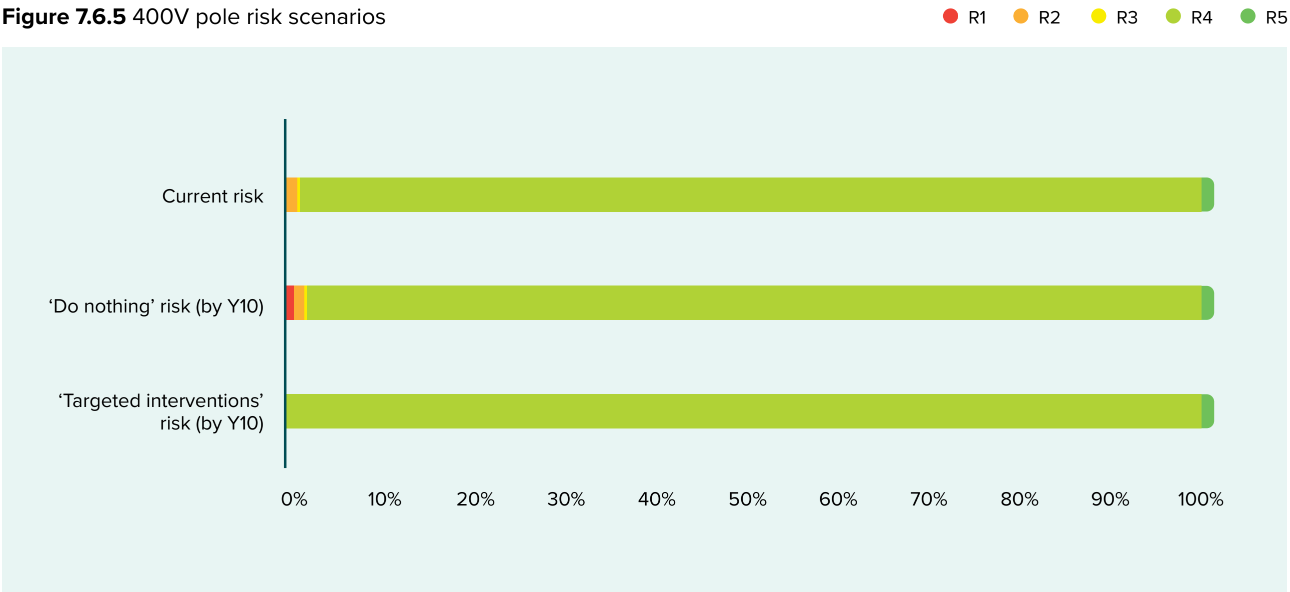
Asset health index	C4	C3	C2	C1	Total
H1	249	442	0	0	691
H2	0	0	0	0	0
H3	1127	3085	7	0	4,219
H4	5090	16524	189	0	21,803
H5	2070	5442	34	0	7,546
Total	8,536	25,493	230	0	34,259

'Targeted intervention' matrix by Y10

Asset criticality index

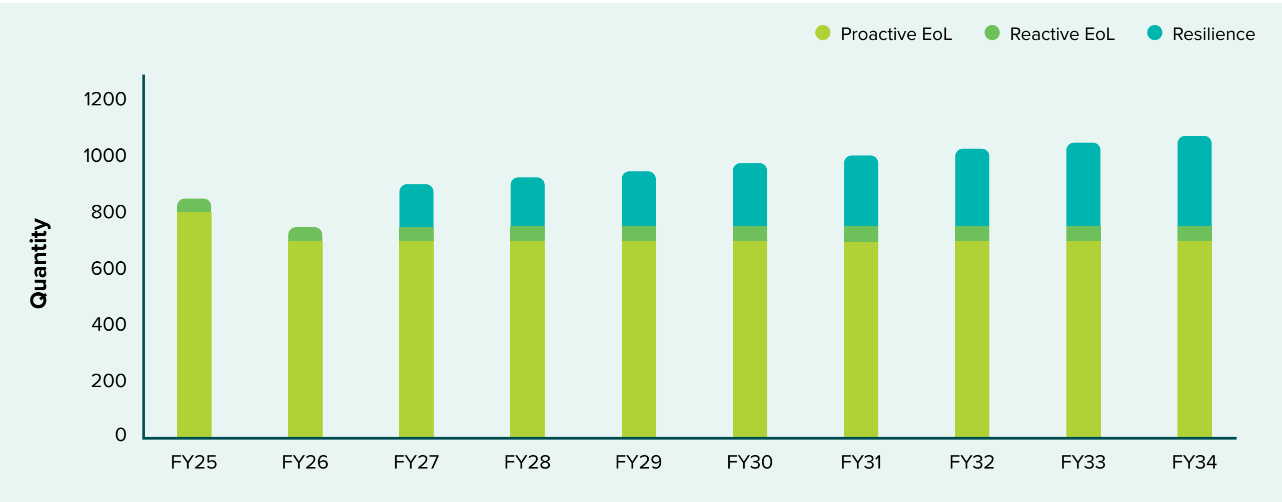
Asset health index	C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	0	0	0	0
H3	116	1368	1	0	1,485
H4	5090	16524	189	0	21,803
H5	3330	7601	40	0	10,971
Total	8,536	25,493	230	0	34,259

Figure 7.6.5 400V pole risk scenarios



To address the increased risk we have identified, we are planning a staged increase in replacement of our mainly timber poles as shown in Figure 7.6.6. This staged increase allow time for our service providers to increase resources to handle the work programme. This forecast has been reduced from the previous AMP. For an explanation, see Section 7.5.5.

Figure 7.6.6 400V pole replacement plan



7.6.5.2 Pole top hardware

For economic efficiency, crossarms and insulators are replaced in conjunction with the pole replacement programme, the line retightening programme, or targeted programmes if required.

7.6.5.3 Conductors

We do not have a proactive scheduled replacement plan for low voltage conductors. Any isolated sections requiring repairs or replacement are addressed under emergency or non-scheduled maintenance. We aim to collect more condition information about our LV network and create a proactive replacement programme in the coming years.

7.6.5.4 Overhead to underground conversion

An option to consider for replacing end of life overhead lines is the possibility of converting to underground cables. As the construction cost for overhead lines is significantly lower than that for undergrounding it is normally not economically justifiable to do so. Most underground conversions are driven and partially funded by third parties such as councils, developers or roading authorities

7.6.5.5 Disposal

Our pole disposal approach is consistent across voltage classes, see Section 7.4.5.2.

Our vegetation management programme is tailored to address the varying risks associated with different voltages, customer types, and diverse geographic areas.

7.7 Vegetation management

7.7.1 Summary

At Orion, our primary responsibility is to ensure the safety, reliability and resilience of our network. While our annual vegetation trimming programme allows us to cut trees within specific zones outlined in the Tree Regulations, the majority of our network faults are caused by vegetation outside these zones, often beyond our control.

In 2020, we re-evaluated our strategy to enhance reliability outcomes for our customers. We are introducing a new programme to address vegetation outside the specified zones – vegetation posing significant risks to network safety and reliability. This initiative involves collaborative efforts with vegetation owners to either remove or mitigate the risks their trees pose to the network.

To streamline and improve the efficiency of our vegetation management, we implemented electronic platforms for data collection, reporting, and ensuring accountability among our service providers.

Our strategy also includes notifying tree owners about potential hazards and conducting public information campaigns. We actively engage with landowners to educate them on the importance of vegetation management around the power network. We identify and remove vegetation at risk of impacting the network both inside and outside the Notice Zone.

Recognising the potential for vegetation to cause significant damage, outages, and safety risks – risks heightened by climate change - we emphasise prevention over cure. We now also take a focused approach to identifying and managing vegetation in problematic areas, aiming to eliminate risks wherever possible.

We have increased our investment in vegetation management and taken into account recent changes in traffic management requirements and safety regulations that have led to increased costs.

7.7.2 Impact of vegetation on our network

Orion's network spans 6,000 km of overhead lines, making it susceptible to the risks associated with vegetation growth. Many of these lines, particularly in rural areas, run parallel to property fence lines and are often bordered by hedges and trees serving as shelter belts. The presence of these hedges, trees, and other vegetation encroaching on the power network poses significant risks to our overhead line assets, as well as to our service providers and the public nearby.

Given climate change impacts on weather patterns, we expect the current level of vegetation management will not be sufficient to address future risks.

Without regular vegetation maintenance, trees and hedges gradually encroach on the overhead network, leading to potential power outages, damage, injuries, and fires. Instances of trees falling onto our lines can result in prolonged outages, impacting communities on a wider scale.

To mitigate these risks, we actively identify and remove trees and vegetation that pose a threat to the network, both within and outside the Notice Zone as defined by the Tree Regulations. Our vegetation management programme is tailored to address varying risks associated with different voltage levels, customer types, and the challenges presented by diverse geographic areas.

7.7.3 Reliability

The proximity of vegetation to the overhead network significantly impacts its reliability and resilience. As highlighted in Orion's Climate Statement, future vegetation growth rates are likely to increase due to warmer and wetter conditions. The Statement also anticipates increased frequency of severe weather events and higher wind speeds. Given climate change impacts on weather patterns, we expect the current level of vegetation management will not be sufficient to address future risks. We recognise Orion needs to take proactive measures now to enhance network resilience from vegetation interference to prevent performance and safety risk from worsening over time.

7.7.4 Issues and controls

The number of outages caused by vegetation has continued to trend upward despite our increasing investment in our vegetation programme, see Figure 7.7.1. Many of these outages are caused by vegetation outside of the cut zones and this has prompted our decision to take a proactive approach to minimise or eliminate the vegetation outside these zones that could have an impact on our network.

There are a number of weather and event faults related to vegetation but are not recorded as a vegetation fault. Figure 7.7.2 shows the amount of weather and events annually, broken down into vegetation related and other events. Although it is hard to be certain, anecdotal evidence suggests it is likely the majority of these vegetation related faults are from vegetation outside the regulation zone.

Figure 7.7.1 Number of outages caused by vegetation

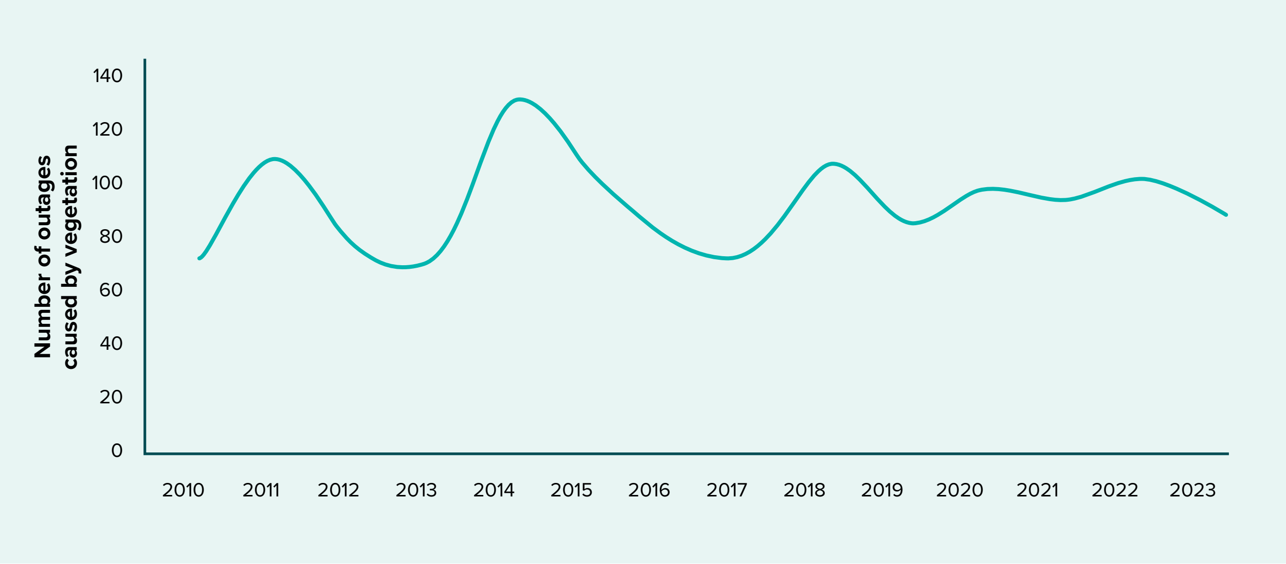
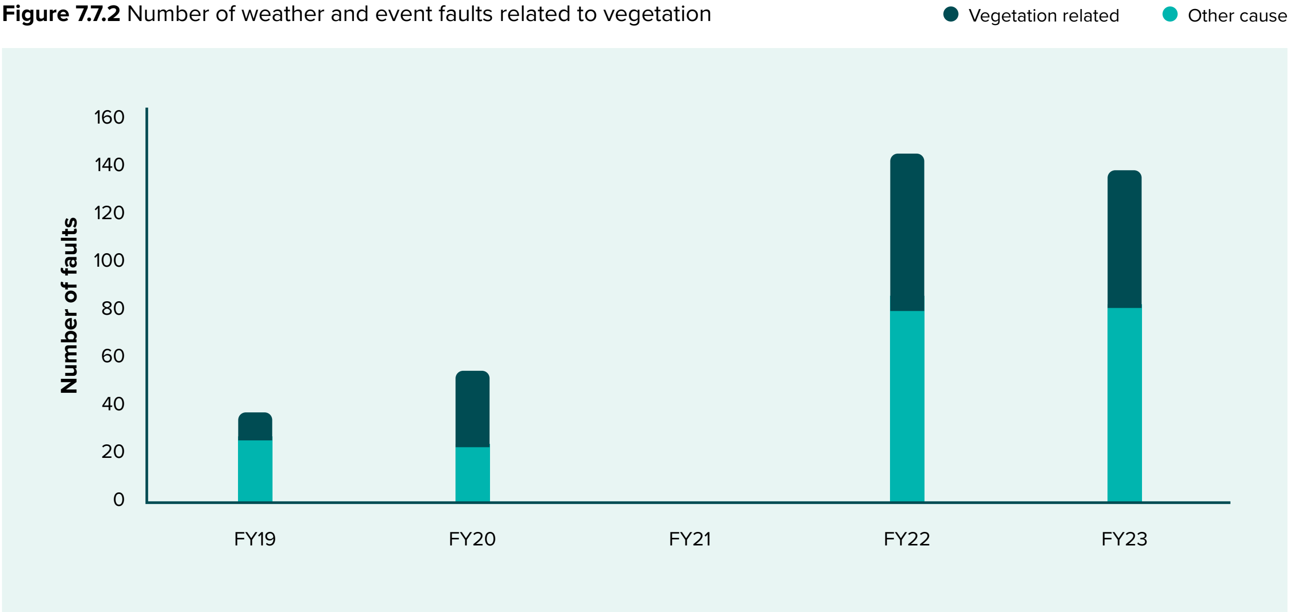


Figure 7.7.2 Number of weather and event faults related to vegetation



7.7.5 Maintenance plan

Orion's overhead high voltage network carries a higher risk compared to our low voltage network. To maintain acceptable performance in our HV network, we conduct vegetation cutting around it every two years, complemented by inspections in alternate years. These inspections, occurring between the programmed cuts, focus on vegetation growing within the regulatory notice schedule. The aim is to both keep the regulation clearance zone free of vegetation while identifying and where feasible addressing trees from outside of the zone that pose a significant risk to the network.

Several programmes are in place to fulfil our responsibilities under the Tree Regulations and minimise risks. These include:

- Inspection of vegetation around the network with appropriate notifications to vegetation owners.
- Safety cuts around both LV and HV networks.
- Targeted negotiations for managing high-risk vegetation arising from outside of the regulated zones.
- Communication with land and vegetation owners to outline responsibilities and propose low-impact planting
- Communication with vegetation contractors, covering the above and emphasising safe working practices.

Our tree management programme engages competent, experienced authorised service providers with formal consent to work near Orion's network. These arborists are familiar with Orion's requirements and execute their work with minimal disruption to the community. All activities adhere to tree regulations and Orion's Technical Specification NW72.24.01 – Vegetation Work Adjacent to Overhead Lines. Orion also raises awareness of the potential electrical hazards for their personnel, and the public.

7.7.6 Vegetation management expenditure

Our operational expenditure on vegetation management progressively increases over time to meet our objectives, which are:

- To reduce vegetation related risk and increase resilience to our HV network from outside of the clearance zone vegetation. This is in preparation for potentially more frequent and intense weather conditions as a result of climate change.
- To broaden the scope of our LV vegetation management program, to reduce overall fault numbers and improve reliability. Currently the program is concentrated on high-risk zones within the Christchurch city region, and we will expand this to encompass the entire network.

Our analysis of the September 2021 severe wind event in our region showed only 3% of vegetation related issues were caused by trees within growth limit zones. This view is supported by the Electricity Distribution Sector Cyclone Gabrielle Review which states only 15% of customer outages were caused by in-zone vegetation.

We have refined our AMP forecast to continue routine trimming programmes and dedicating additional expenditure on removing trees from out-of-zone areas. This represents a notable increase in Orion’s spending on vegetation management compared to spending in recent years.

This forecast increase is driven by our commitment to engage more with tree owners, foster community communication, and conduct risk-based assessments. These efforts allow us to better prioritise our tree trimming schedule. As these priorities are established, our 2024 AMP forecast indicates a gradual increase in activity, directing budget allocations where they are most needed, such as collaborating with customers to trim trees beyond designated zones. Through our programmes, we aim to enhance feeder resilience during severe weather events which is a key priority for our customers.

Our subtransmission underground cable network delivers electricity from Transpower's GXPs to substations across the region.

7.8 Underground cables – subtransmission

7.8.1 Summary

Our underground subtransmission cable network distributes electricity from Transpower GXPs to Orion's Zone Substations across the region. This network consists of both 66kV and 33kV cables, typically with N-1 redundancy which means we have one back-up in the event of maintenance or failure. A significant portion of our network consists of 66kV Self Contained Oil Filled (SCOF) cables which are aging. While generally dependable, these cables require maintenance, require specialist expertise to repair, and have lengthy recovery times in the event of external damage or a fault.

Following a risk assessment of our 66kV oil filled cables, we concluded it is essential to replace them. This decision is primarily driven by the potential risk of an Alpine Fault earthquake, which would likely lead to multiple large-scale outages with long recovery times. These disruptions would compromise the resilience of our network and the service levels expected by our customers.

Our objectives for this asset class are:

- Provide a high level of reliability commensurate with our SAIDI and SAIFI targets and network security requirements.
- Ensure network security and resilience by ensuring that the system is capable of withstanding or quickly recovering from credible natural emergency events.
- Provide required services at lowest lifecycle cost.
- Be sensitive to the environment.

7.8.2 Asset description

We have 12 circuits covering 40km of 66kV oil filled cables installed from 1967 to 1981 in central Christchurch.

While our oil filled cables are in serviceable condition and capable of continuing operation, they have resiliency issues. Their construction makes them vulnerable to earthquake-induced ground movements, and repairs are labour-intensive, requiring scarcely available specialised skills and equipment. Restoration of a single fault typically takes several days at a minimum and longer if multiple failures occur simultaneously as would be expected in a significant earthquake event such as an Alpine Fault rupture. Given the limited quantity of these cables and their infrequent need for repairs, maintaining in-house repair capabilities is impractical. This means we are reliant on specialist service providers who have limited availability, further compromising our response capability.

Oil filled cables can experience oil leaks if the cable sheath is damaged. These leaks are typically small in volume but expensive and difficult to detect and repair. Environmental concerns arise if leaks are large or if they occur in sensitive areas. Finally, oil filled cables have higher routine maintenance requirements than XLPE types, such as maintenance and monitoring of oil supply and oil pressure monitoring systems located throughout cable routes. For these reasons we have initiated a project to replace our oil filled cables with resilience as the primary driver, see Section 8.4.

For 66kV and 33kV voltages, XLPE Cables have been our standard since 2001. We also have 2km of legacy Paper Insulated Lead Covered (PILC) 33kV cable.

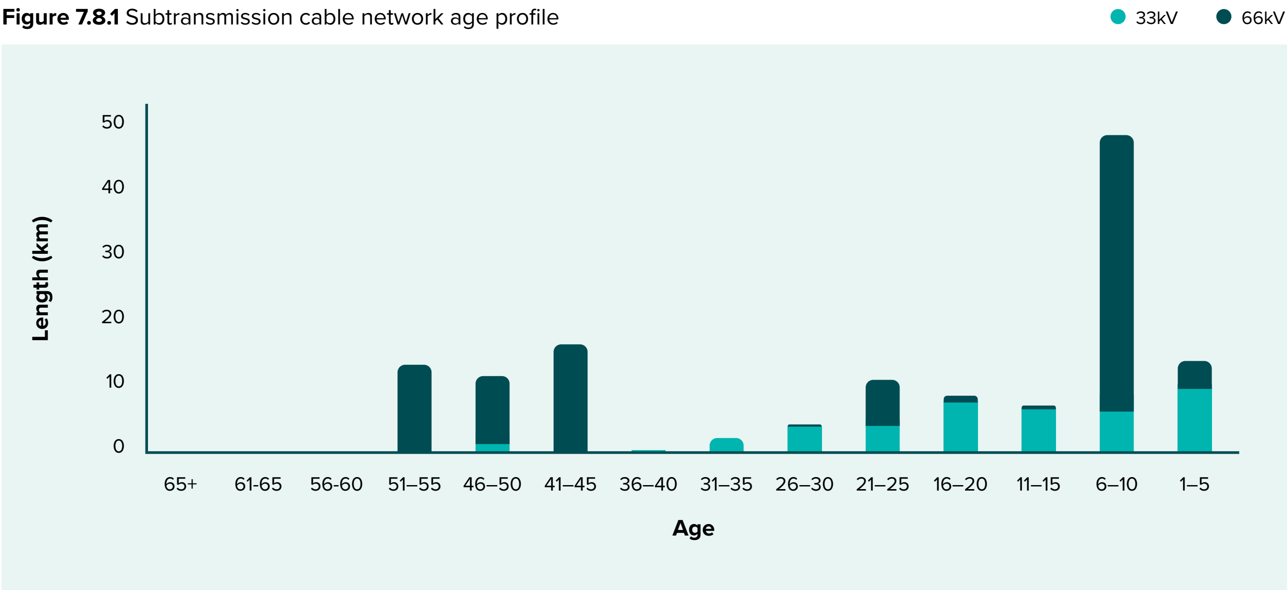
Table 7.8.1 details our sub transmission cable inventory by type and voltage.

Table 7.8.1 Subtransmission cable length by type

Cable type	Length (km)		
	33kV	66kV	Total
PILCA	2		**2**
XLPE	40	54	**94**
3 core oil	0	40	**40**
Sub-total	41	95	
Total			**136**

Figure 7.8.1 shows the age profile for our 33kV and 66kV network. Most of our cables are relatively new being less than 25 years old. Our fleet is broadly in two grouping: oil filled cables older than 40 years and XLPE cables less than 25 years with a significant quantity installed as part of our post-earthquake recovery and resilience work.

Figure 7.8.1 Subtransmission cable network age profile



7.8.3 Asset health

7.8.3.1 Condition

Due to Orion's network configuration, our 66kV cables are operated well below their maximum thermal ratings, under normal network conditions. This means they are not susceptible to accelerated degradation from thermal cycling. We have completed our programme to replace joints in our oil filled cables that have known design deficiencies which make them susceptible to thermal cycling or ground movement. Some of our oil filled cables have returned poor sheath test results indicating some outer sheath damage. This is being monitored with repairs being considered in conjunction with our oil filled cable replacement programme.

We assess the condition of our subtransmission cable network based on various factors, including the age of the installed cables, their history of faults, sheath tests, and, when appropriate, online partial discharge and tan delta tests. In the case of oil filled cables, we also consider cable fluid leakage rates. If failures do occur, we conduct a comprehensive investigation to identify the root cause, whether it is related to external factors like third-party damage, workmanship issues, specific design or manufacturing problems, or in service deterioration. Due to the very large investment to replace ageing cables, our decisions are based on case-by-case engineering investigations rather than predictive models.

Our XLPE cables are still relatively new being well within their expected operating lifespan and are considered to be in good serviceable condition. We do not foresee the need for end-of-life replacement of XLPE cables during the current AMP period. In the previous AMP period, we identified subpar work in certain 33kV joints and have completed a joint replacement programme to address this issue. The limited number of 33kV PILC cables in service are deemed to be in serviceable condition and are not expected to need replacement during the current AMP period.

7.8 Underground cables – subtransmission continued

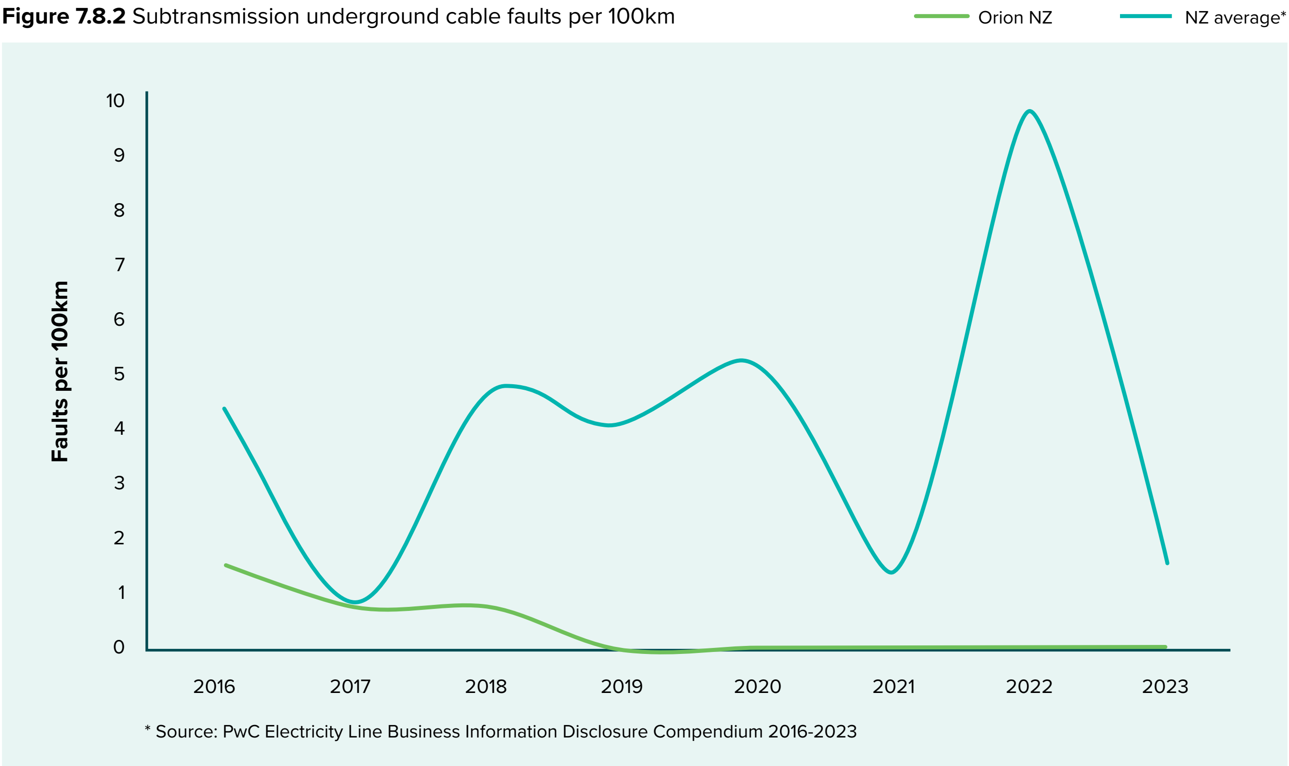
7.8.3.2 Reliability

Following a period of reduced reliability due to latent defects stemming from the 2011 earthquake, our 66kV cables are now achieving target reliability levels after addressing and resolving these defects. We do encounter occasional issues related to terminations and oil leaks, requiring immediate emergency repairs.

During the years from 2015 to 2018, we experienced eight instances of 33kV joint failures, primarily attributed to inadequate jointing techniques. However, since the implementation of a joint replacement programme, there have been no further occurrences of 33kV joint failures.

Figure 7.8.2 shows Orion's subtransmission underground cable faults compared to the NZ average.

Figure 7.8.2 Subtransmission underground cable faults per 100km



7.8.3.3 Issues and controls

While subtransmission cable failures are rare, they can expose large numbers of customers to reduced security while they are being repaired. An additional failure related to the circuit could cause a widespread, extended outage. Table 7.8.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.8.2 Subtransmission cable failure controls

Common failure cause	Known issues	Control measures
Material degradation	Partial discharge degrades the cable insulation which can result in complete failure leading to an outage.	Targeted offline partial discharge testing to identify joint or in run cable defects before failure. Utilising ultrasonic and partial discharge monitoring within zone substations to identify early signs of potential cable termination failure.
Quality of installation	Poor quality joint installation can lead to premature failure impacting reliability. Poor cable installation techniques including improperly compacted or incorrect fill material and overstressing or over bending can lead to premature failure.	Cable jointers are trained and certified as competent by the joint supplier for the specific joint type. Perform root cause investigations of failures to determine if there are common causes (such as for example work or material quality) so that mitigation or remediation actions can be identified. Quality control surveillance of service providers during the laying of cables to verify correct installation techniques are being employed.
Third party interference	Third parties dig up and damage our cables during excavations.	33kV and 66kV cables require a consent application and standover process for any work in their immediate vicinity. Advertising to create awareness of hazards of working near cables. Free training on working safely around cables. 33kV cable sheaths are now specified as orange in colour to allow easier identification. Proactive promotion of cable maps and locating services to parties involved with civil excavations.
Skills availability	Oil filled cables require specialised skills for repairs.	Agreements in place with specialised service providers to maintain local repair capability. A selection of repair joints and cable is retained in stock.
Oil leaks	Oil filled cables if breached can cause discharge a loss of oil causing electrical damage and failure to the cable. Oil leaks can contaminate sensitive environmental areas.	Periodic sheath testing to identify failure of the insulating outer sheath which is an early indicator of potential sheath corrosion and subsequent leaks. Monitoring of cable pressures to identify developing problems so that they may be rectified in their early stages.

7.8.4 Maintenance plan

Our maintenance plan for subtransmission cables is summarised in Table 7.8.3.

Table 7.8.3 Subtransmission cable maintenance plan

Maintenance activity	Strategy	Frequency
Cable inspection	Oil filled cable oil level checks	2 monthly
	Cable sheath tests and repairs	From annually to at least 4 yearly
	Partial discharge testing	As required
	New or repaired cable benchmark testing	As required

7.8.5 Replacement plan

Our 66kV oil filled cables are planned for replacement during the AMP period to meet our security and resilience objectives. For more details of this project, see Section 8.4.

7.8.5.1 Disposal

Our oil filled replacement programme will require decommissioning of our oil cables. As part of this project we will develop a decommissioning procedure based on current industry best practice which we anticipate will include vacuum removal of oil and capping of the cable so that it may be safely left in place in a deenergised state.

90% of our network of 11kV underground cables are in the urban area of Christchurch which we call Region A.

7.9 Underground cables – distribution 11kV

7.9.1 Summary

Orion's network of 11kV underground cables delivers power from our zone substations to our customers' premises. 90% of our underground network is in the urban area of Christchurch which we call Region A. The reliability of our 11kV cables is currently below our target and the New Zealand Average and we are planning a programme to investigate and implement improvements to our condition assessment and renewal planning processes for this asset class.

Our objectives for this asset class are:

- Maintain a failure rate that is consistent with SAIDI and SAIFI targets for this asset class.
- Prevent failures that could result in harm to persons or property.
- Provide service levels at lowest lifecycle cost.

7.9.2 Asset description

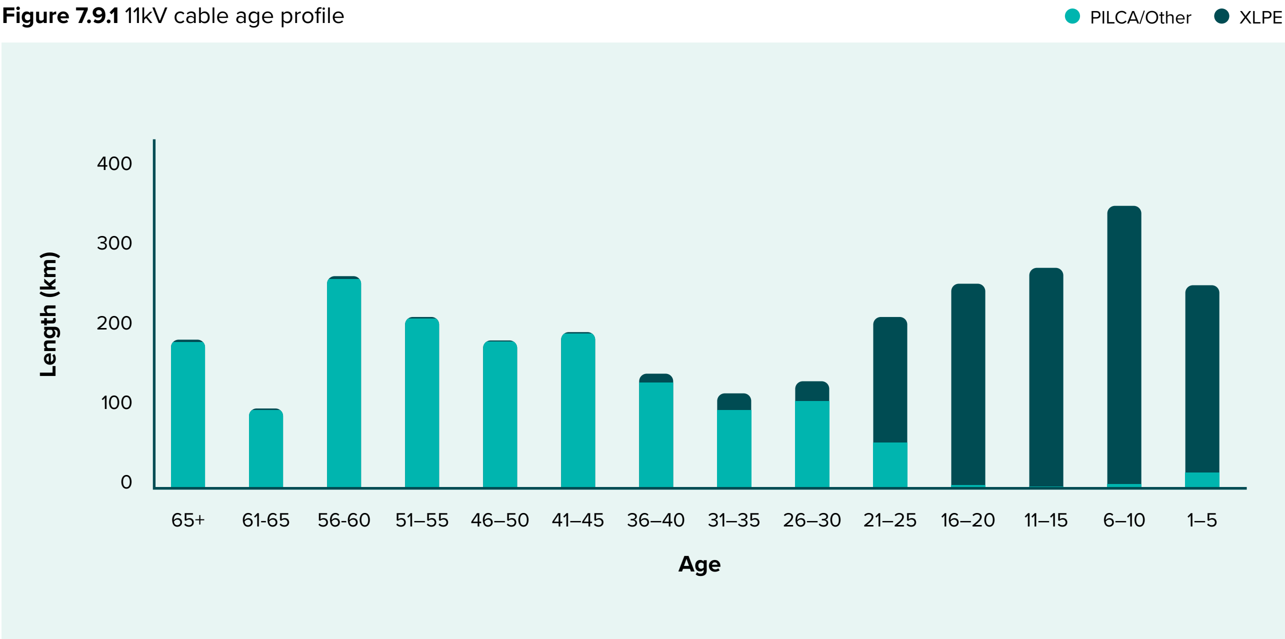
There are two main types of 11kV underground cable in our network:

- **PILCA** – Paper Insulated Lead Covered and Armoured cables
- **XLPE** – Cross Linked Polyethylene insulated power cables

Table 7.9.1 11kV cable length by type

Cable type	Length (km)
PILCA	1,537
XLPE	1,309
Others	10
Total	**2,856**

Figure 7.9.1 11kV cable age profile



7.9.3 Asset health

7.9.3.1 Condition

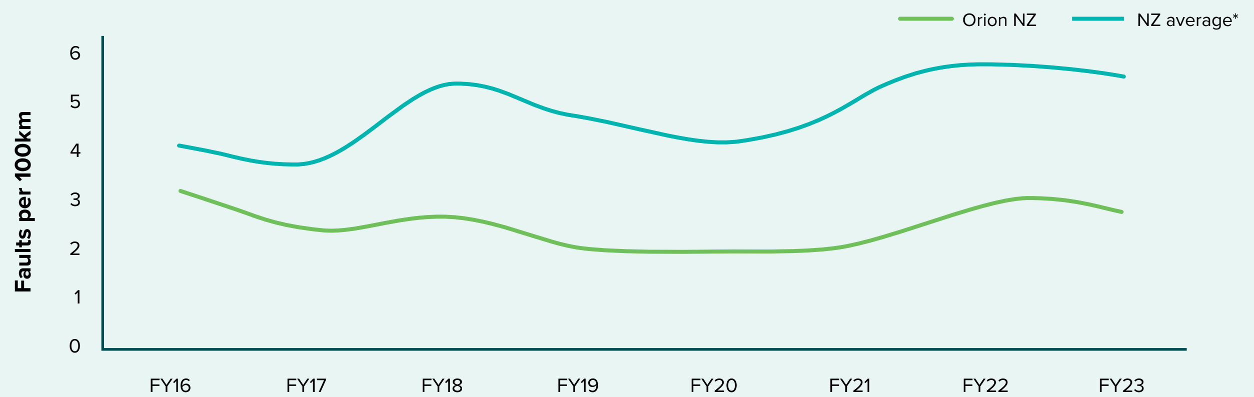
The condition of these cables is assessed by a combination of age in service and monitoring of failures to identify failure clusters. We also receive feedback on the internal cable condition from contractors when they conduct cable fault repairs. Condition testing of a sample of varying cable types and ages has been undertaken using offline partial discharge mapping. While a limited amount of partial discharge was noticeable in a few joints this has not proved effective for identifying potential defects or end of life criteria. Due to the limited cable condition data available we do not currently use predictive modelling for estimating cable end of life and renewal requirements.

7.9.3.2 Reliability

In FY23, 11kV cable faults contributed 13% of the total unplanned SAIDI and 23% of the total unplanned SAIFI. Our failure rate per 100km is currently lower than the New Zealand average and within our target for this asset class.

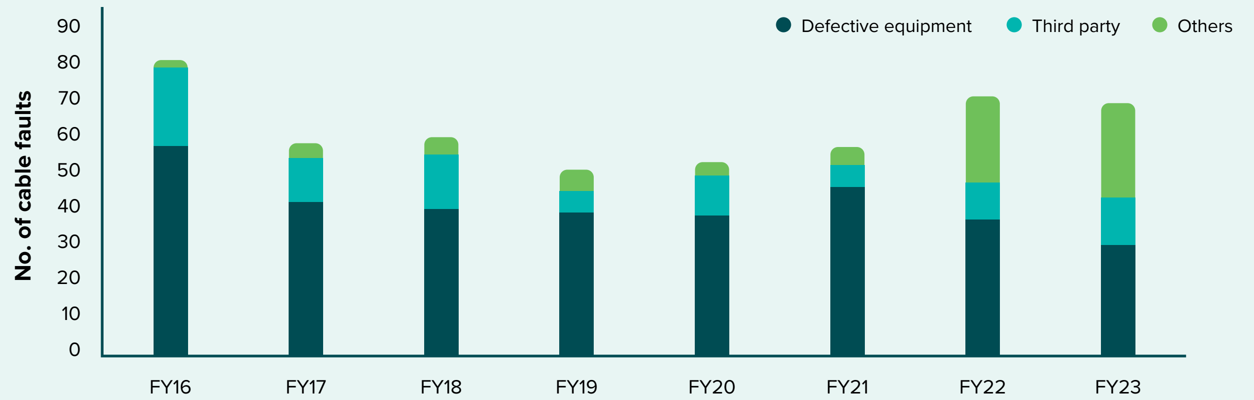
Our termination maintenance programmes have been effective in keeping the failure numbers low. The number of cable, joint and termination failures, is shown in Figure 7.9.3. 'Others' refers to vehicle collision and weather related events where it caused a failure on the underground to overhead termination located on a pole. It also includes underground faults where the cause is unknown.

Figure 7.9.2 Faults per 100km for 11kV underground cable



* Source: PwC Electricity Line Business Information Disclosure Compendium 2016-2023

Figure 7.9.3 Cause of 11kV cable faults



7.9 Underground cables – distribution 11kV continued

11kV cable failures are broken down to approximately 50% joint, 40% run of cable and 10% termination. Joint failures are due to a combination of installation quality problems and ageing from time and thermal cycles. 'Run of the cable' failure is usually due to latent third-party damage or defects from manufacture.

At this time, we have not identified any clustering or common causes that allow us to proactively and cost effectively identify and replace 11kV cables or joints. Our termination maintenance programmes for MSUs have been effective in keeping termination failure numbers low in comparison with other causes. The number of cable, joint and termination failures, is shown in Figure 7.9.3. 'Others' refers to vehicle collision and weather-related events where it caused a failure on the underground to overhead termination located on a pole. It also includes vandalism related faults, which has significantly increased in FY22 and FY23. Vandalism has historically been negligible; however, it now makes up approximately 90% of the 'Others' faults. Despite the increase, it has had no noticeable effect on network performance.

7.9.3.3 Issues and controls

Table 7.9.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.9.2 11kV cable failure control

Common failure cause	Known issues	Control measures
Workpersonship	Termination and joint failures can occur due to poor quality of work and or harsh environmental conditions. It can lead to partial discharge which if not detected can cause electrical breakdown resulting in an outage and possible safety consequences.	Cable jointers are qualified, competent and trained to install specific products. Ultrasonic and partial discharge monitoring of terminations in zone substations. Routine substation inspections identify failing 11kV terminations.
Third party activities	Third parties can damage our cables while undertaking civil works through either direct contact damage or by causing improper ground settlement through incorrect fill material and compacting.	We run a cable awareness programme targeted at civil works contractors to minimise the risk of cable disturbance while digging near network cables. We now specify orange coloured cable sheaths to provide visual indication of live cables. Proactive promotion to service providers of cable maps and locating services. No joints are allowed within road intersections.
Insulation failure	Deterioration of cable insulation caused by partial discharge and or deterioration of the bulk dielectric material.	We currently test on average of two cables per year for partial discharge mapping and dielectric loss angle (tan delta).

7.9.4 Maintenance plan

The maintenance plan for 11kV underground cables is shown in Table 7.9.3. Due to the inaccessibility of 11kV cables, opportunities for inspection and maintenance are limited. We have, however, focused on inspections and associated corrective maintenance for the cable terminations of MSUs which are relatively accessible for inspection and are susceptible to failure when exposed to damp or contaminated condition.

Table 7.9.3 11kV cable maintenance plan

Maintenance activity	Strategy	Frequency
MSU terminations	Inspections of MSU terminations, reporting grease terms and surface partial discharge	6 months
Diagnostic cable testing	Partial discharge and Tan Delta testing	Targeted ongoing

7.9.5 Replacement plan

Our current strategy for replacement of cables is to reactively replace short sections of cable that have faulted multiple times or have been found to be in poor condition when excavated and opened for repair. Over the 10-year period of this plan, we have allocated budget to enhance our understanding of our 400V low voltage network by leveraging smart meter data. We will look for insights into usage patterns and identify any constraints at connection points which indicate the potential for future expenditure. We will replace end-of-life cables identified through this process as part of our LV reinforcement programme. For more detailed information, see Sections 8.4.4.2 and 8.4.4.3.

7.9.5.1 Disposal

Where 11kV cables are installed in ducts they are removed and recycled to recover metals, with remaining materials being disposed of safely. Where direct buried, cables will generally be capped and left in situ.

Our 400V cable network is 3,300km and delivers electricity to street lights and customers' premises largely in Region A.

7.10 Underground cables – distribution 400V

7.10.1 Summary

Our 400V LV underground cable system has two key components: reticulation cables and ground-mounted distribution cabinets and distribution boxes. These elements are the final stage in our distribution system, providing electricity to both our customers' premises and council-owned street lights. Most of this 400V LV underground cable network is in urban areas in Region A. This network also includes around 60,000 distribution cabinets and distribution boxes that provide fusing and isolation for customer service lines.

Historically the 400V LV cable network has been less critical than other network voltages due to the limited numbers of customers affected by equipment failure. Now, we are increasing investment in the 400V LV underground cable system in this AMP period to address legacy safety concerns and prepare this part of the network for increased levels of DER technologies. These technologies are expected to increase the demand and customer reliance on this asset.

We are implementing a programme to relocate legacy Orion-owned supply service fuses which are currently located on customer premises, to align with current safety and responsibility standards.

Our objectives for this asset class are:

- Provide reliable service to meet customer expectations.
- Prevent failures that could cause harm to persons or property.
- Provide service at lowest lifecycle cost.

7.10.2 Asset description

The 400V LV underground asset class comprises two distinct subsets: LV cables and LV enclosures located at the surface to accommodate fuses, links and connections to customer owned service lines.

7.10.2.1 LV cables

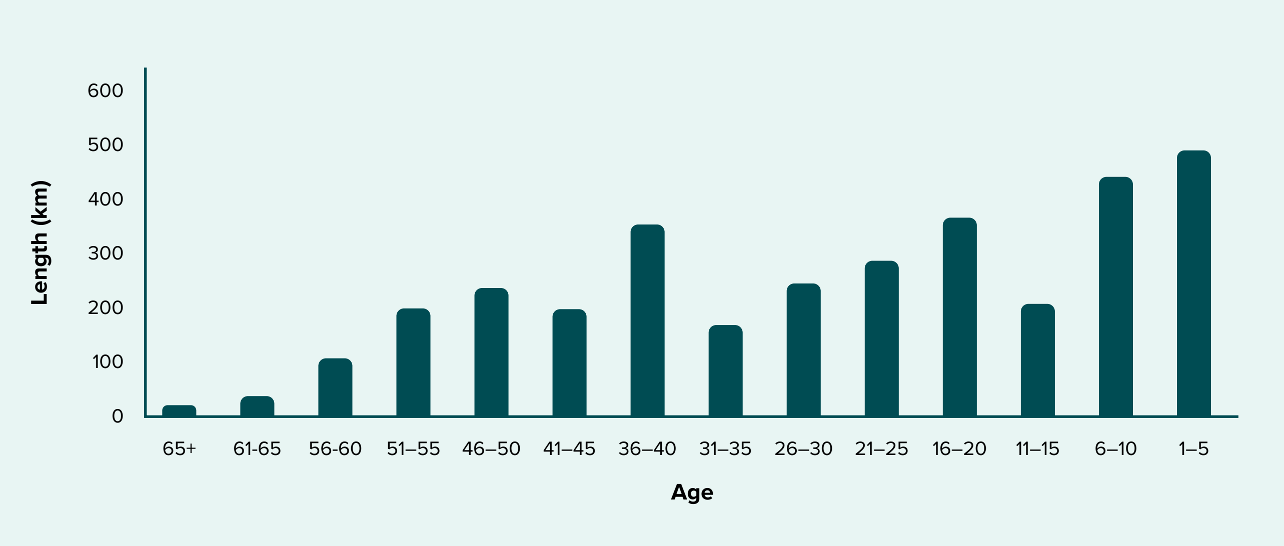
We have two groups of cables: distribution cables and street-lighting cables as shown in Table 7.9.1. They are:

- **Distribution cables –** we have a substantial population of legacy Paper Insulated Lead Covered (PILC) cables, with some cables approaching 90 years in service. PVC insulated cables superseded PILC types primarily due to cost and were installed from 1966 to 1974. XLPE insulation was introduced in 1974, mainly because it has better thermal properties than PVC, allowing for higher operating temperatures and improving economics.
- **Street lighting cables –** approximately 60% of this cable is included as a fifth core within LV 400V distribution cables.

Table 7.10.1 400V LV cable and street-lighting networks cable type

Cable type	Length (km)
PVC	581
PILCA	314
XLPE	2,473
Total	**3,368**
Street lighting cable	2,894

Figure 7.10.1 400V LV cable age profile



7.10.2.2 LV enclosures

We have two groups of enclosures, see Table 7.10.2. They are:

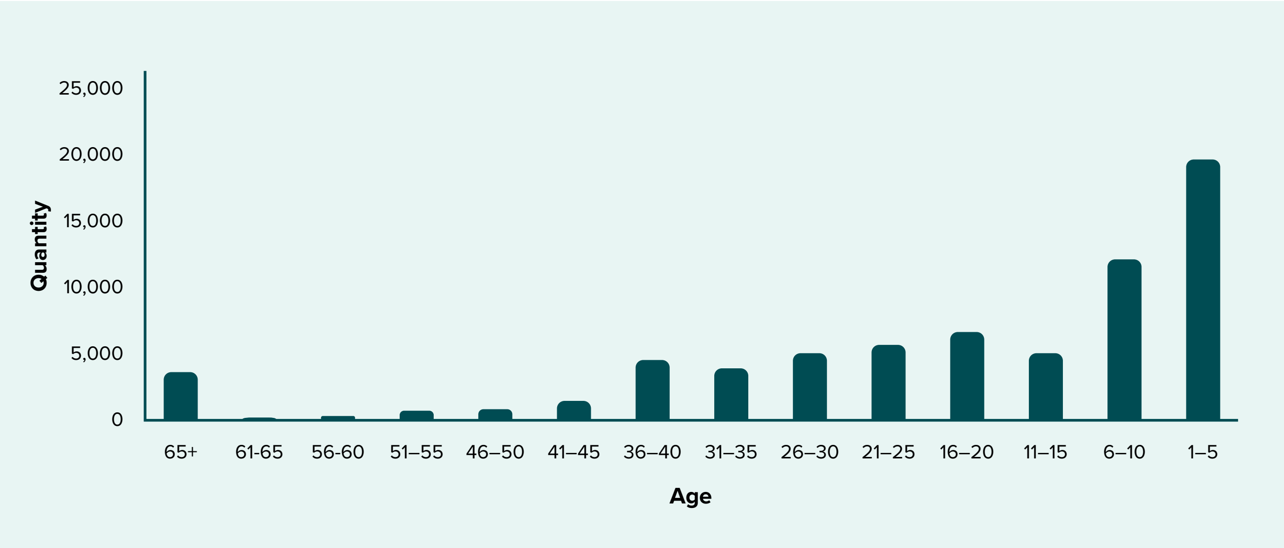
- **Distribution cabinets –** provide for configuration of the LV network to allow isolation and interconnection through manually operated links. We have two types of distribution cabinets: older steel enclosures and PVC enclosures with a steel frame.
- **Distribution boxes –** typically installed above ground on alternate property boundaries, we have several types of distribution boxes in service. The majority feature a PVC cover on a steel base frame, while some older types are constructed with concrete and steel.

The age profile of our LV enclosures is shown in Figure 7.10.2.

Table 7.10.2 Distribution enclosure type

Type	Quantity
Cabinet	6,948
Box	61,553
Total	**68,501**

Figure 7.10.2 LV enclosures age profile



7.10.3 Asset health

7.10.3.1 Condition

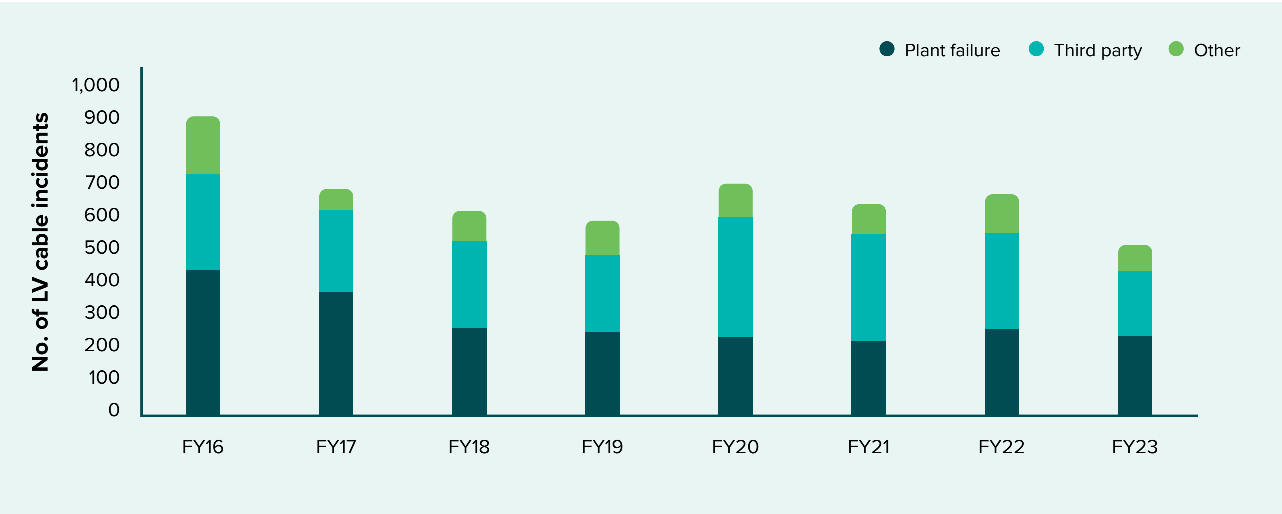
We inspect our distribution cabinets and boxes every five years and rectify any defects or condition issues. Due to inaccessibility, we cannot readily inspect the condition of the LV underground cables. Our approach is to repair upon failure, replacing short runs of cable at the time of repair when the cable is found to be in an end-of-life condition. We also monitor failures and failure rates to identify common causes or clusters of failures.

7.10.3.2 Reliability

While we are not obligated to record SAIDI/SAIFI for our LV networks, we proactively gather performance data for prudent asset management and to maintain a satisfactory service for our customers. Figure 7.10.3 shows the number of LV underground emergency maintenance call-outs addressed by our service providers.

Our data indicates that the overall failure rate has decreased compared to the FY14-FY16 levels. This reduction is attributed to a decrease in the number of third-party damage incidents, likely resulting from our education efforts and a general reduction in the volume of third-party excavation work. The equipment failure rates remain broadly similar and, at present, does not necessitate a change in our management strategy.

Figure 7.10.3 Cause of 400V LV cable incidents



7.10.3.3 Issues and controls

Table 7.10.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.10.3 400V LV cable network failure controls

Common failure cause	Known issues	Control measures
Material degradation	Quality of work installing cable joints and terminations.	Regular process audits to verify contractor procedures and competence. Cable jointers are qualified, competent and trained to install specific products.
Termination failures leading to risk of fire on customer premises	Historically, many customer service cables were connected directly to the underground network cables via a tee joint, with customer protection fuses in their meter box. Failure of the fuse assembly could lead to a fire on the customer's premises.	For increased safety, we are implementing a supply fuse relocation programme to eliminate tee joints and relocate fusing to modern distribution boxes installed on the property boundary.
Access by public	Enclosures may be damaged allowing inadvertent access by public.	Enclosures are inspected on a five-year cycle for security and integrity. They also display warning labels and contact details to encourage the public to report any damage.
Third party activities	Third parties dig up and damage our cables during road construction or other activities.	Identified shallow conductors are addressed Cable Digging Awareness Programme – A cable awareness programme running in association with external service providers to minimise the risk of cable interruption for any digging in close proximity to the network cable. New cable is now required to be installed with an orange sheath to allow easier identification. Extensive public safety advertising campaigns.

7.10.4 Maintenance plan

Our scheduled maintenance plan is summarised in Table 7.10.4.

Table 7.10.4 400V LV underground maintenance plan

Asset	Maintenance Description	Frequency
Distribution cables and terminations	Visual inspection of insulation on cable to overhead terminations. Where insulation is degraded or damaged it is scheduled for rectification.	5 years
Distribution enclosures	Visual inspection of the above-ground equipment and terminations with identified defects rectified.	5 years

7.10.5 Replacement plan

We are continuing the supply fuse relocation programme to reduce the risks associated with a historical practice where some LV supply fuses were installed in the customer's meter box. This programme, which relocates the fuse to a distribution box on the property boundary, is scheduled for completion in FY27. We are also gradually upgrading our existing distribution cabinets to a more secure design.

Budget allocations have been made for end-of-life cable replacement from FY28 and beyond.

7.10.5.1 Disposal plan

Underground cables that were installed in conduits or are otherwise easily removed are recycled to recover metals for re-use. Direct-buried cables are typically capped and left in place. Enclosures are also recycled, with steel components being recovered. Any polymer materials are disposed of appropriately.

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network.

7.11 Switchgear

7.11.1 Summary

Switchgear provides the capability to control, protect, isolate, and configure our electricity network. The switching of loads and the interruption of faults are technically demanding tasks, and equipment must be appropriately specified, manufactured, tested and installed to ensure that it can function reliably and safely. There has been significant advancement in switchgear technology over the past 50 years, with modern equipment incorporating design features that substantially reduce the likelihood of serious injury to operators in the event of equipment failure.

Orion operates a significant population of switchgear that lacks modern safety features. Some of our switchgear utilises sulphur hexafluoride gas (SF_6) as an insulant and interruption medium. SF_6, is a very potent greenhouse gas and any loss to the atmosphere must be minimised and accounted for. Orion has maintenance programmes and operating procedures in place to mitigate this risk and we are gradually phasing out such equipment. Our replacement programmes include an evaluation of these risks, with projects prioritised based on a risk assessment. For more detail on our management of SF_6 risk, see Section 6.

The asset class objectives for switchgear are:

- Enable safe and reliable control and configuration of the network.
- Less than 0.8% annual SF_6 loss to the atmosphere of total installed equipment gas.
- No safety events with the potential to injury to persons.
- Minimise whole of life costs.

7.11.2 Asset description

In this section we discuss the types of switchgear installed on Orion's network.

7.11.2.1 Circuit breakers

Circuit breakers are devices that can both interrupt fault currents during system abnormalities and switch load currents during normal routine operation. They are strategically placed in the network to meet requirements for system protection, isolation, and operating flexibility. Due to the very high energy levels that occur during fault interruption, circuit breakers must be appropriately specified, operated, tested and maintained. Should a failure occur, the consequences can be significant, placing personnel and adjacent plant at risk. Table 7.11.1 below provides descriptions and statistics for the various types of circuit breakers we have in service.

Table 7.11.1 Circuit breaker description by type

Voltage	Type	Description	Interruption medium	Quantity
66kV	**Outdoor** Circuit breaker (zone substation)	We have both dead-tank and live-tank circuit breakers predominantly in outdoor switchyards. However, some outdoor-type circuit breakers have been installed indoors in specially designed buildings for security, aesthetics, and lifecycle reasons. The majority of our 66kV circuit breakers are predominantly of a dead-tank design and use SF_6 gas as the interruption medium.	Oil	9
			SF_6	108
33kV	**Outdoor** Circuit breaker (zone substation)	Those installed before 2001 are mainly outdoor, minimum oil interruption type. Since 2001, we have predominantly installed indoor vacuum-type switchgear.	Oil	24
			Vacuum	3
	Indoor Circuit breaker (zone substation)	These are metal-clad cabinet switchboards with enclosed busbars and withdrawable circuit breaker trucks. Compared to traditional outdoor circuit breakers, these circuit breakers have the advantage of reduced space requirements, improved security, and safety. Since 2018, installed indoor circuit breaker switchboards have been rated for full arc containment, improving operator safety.	SF_6	6
			Vacuum	42
11kV	**Indoor** Circuit breaker (zone substation)	Substation circuit breakers are installed indoors at zone and distribution substations and are used for the protection of primary equipment and the distribution network. Older types use oil or SF_6 gas as an interruption medium, while those installed since 1992 are of vacuum interruption type. Circuit breakers installed since 2019 are rated for full arc containment, improving operator safety.	Oil	597
			SF_6	32
			Vacuum	762
	Line circuit breaker (pole mounted)	These are installed in strategic locations to improve reliability by providing line reclosing and isolation for a portion of a feeder.	SF_6	1
			Vacuum	83

7.11 Switchgear continued

Figure 7.11.1 shows the age and type profile for our 33kV and 66kV circuit breakers. The different types are:

Figure 7.11.1 Subtransmission circuit breaker age profile

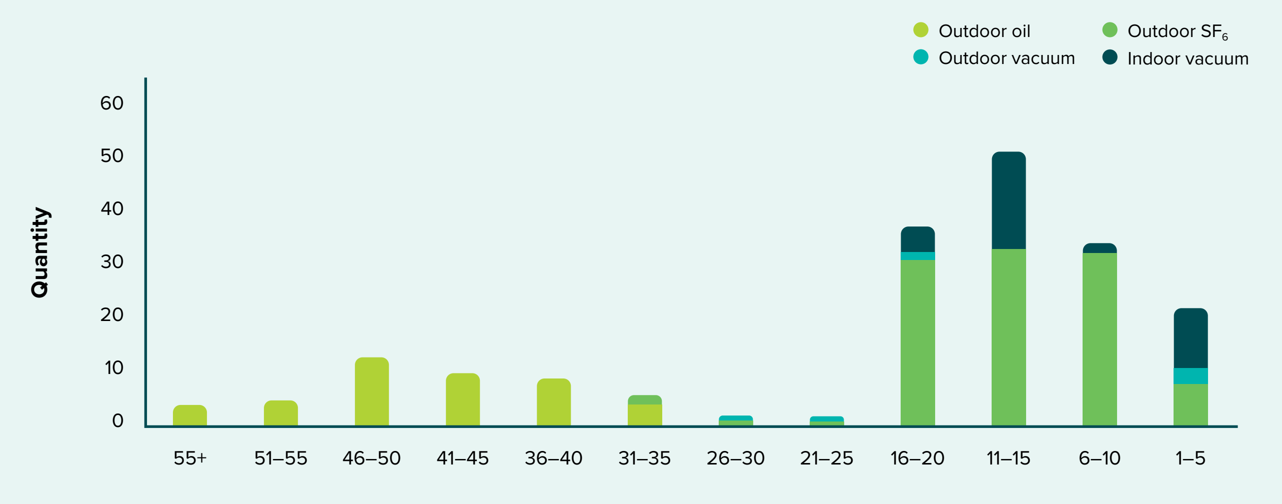
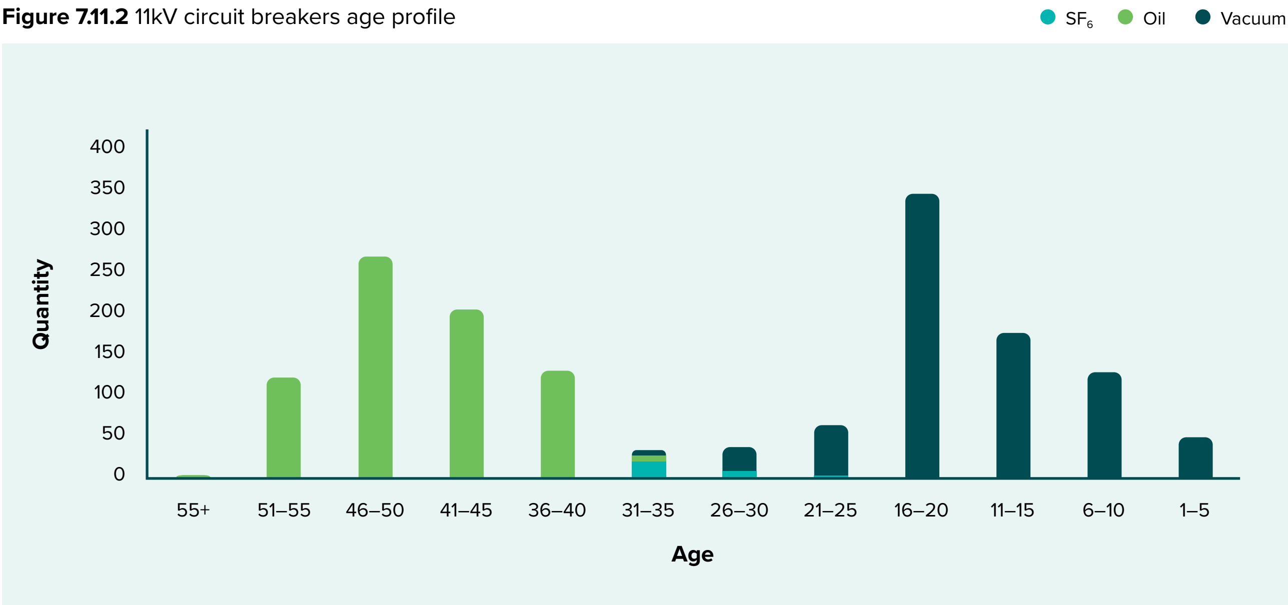


Figure 7.11.2 shows the age profile for our 11kV circuit breakers. 11kV circuit breakers installed before 1988 use oil as the interruption medium. 11kV circuit breakers installed after 1988 are predominantly vacuum interruption type with SF_6 making up a small portion that were installed between 1988 and 1997.

Figure 7.11.2 11kV circuit breakers age profile



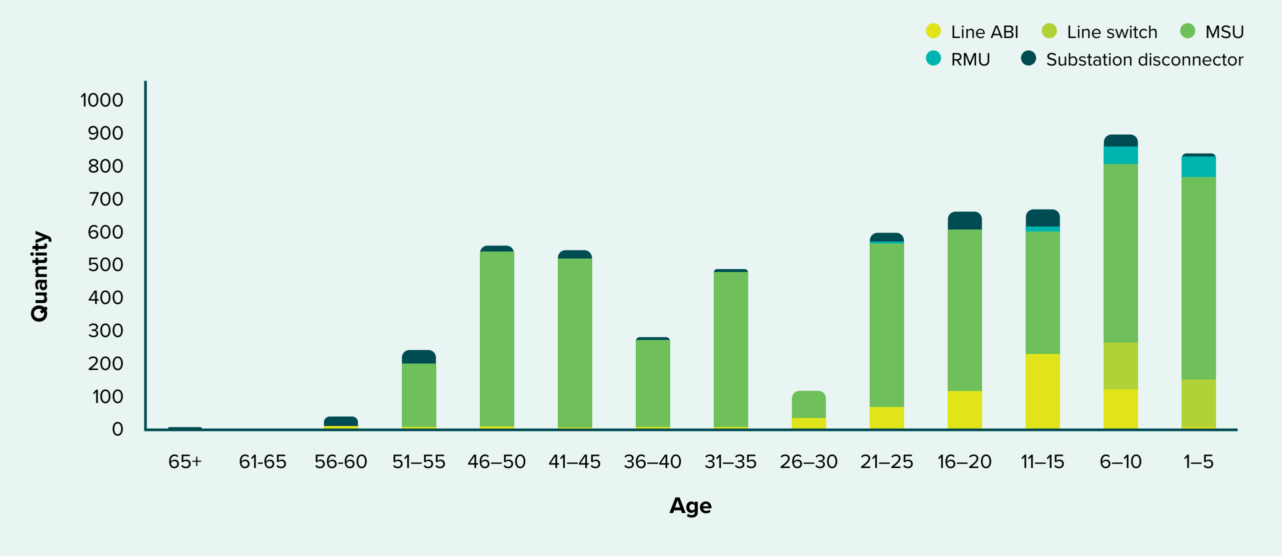
Switches

Switches are used as isolation points to allow access to equipment for maintenance or repairs and to facilitate flexible network configuration. The various types of switches in use are described in Table 7.11.3.

Table 7.11.2 Switchgear description by type

Voltage	Type	Description	Quantity
66kV & 33kV	Substation Disconnector (DIS)	Disconnectors are used as isolation points in the zone substation switchyard to reconfigure the substation bus for fault restoration, or for isolating plant for maintenance. They are typically mounted on support posts or hang from an overhead gantry. Most are simple manually operated devices. Since 2016, we have added motor operated disconnectors to some sites, which mitigate safety risks, as the operator can maintain a safe distance during switching.	291
33kV & 11kV	Line Air Break Isolator (ABI) (pole mounted)	These are installed on our rural overhead network and some have load break capability. We no longer install new ABIs and have been replacing old ABIs with enclosed line switches.	6 (33kV) 525 (11kV)
	Line switch (pole mounted)	These units are rated at 630A with a vacuum load breaking switch. They are installed to be operated on-site by hot-stick or remote operation. These switches are installed when older ABIs are due for replacement.	272
11kV	Magnefix Ring Main Switching Unit (MSU)	MSU's are an independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. MSUs are compact and have a substantially smaller footprint requirement compared to other switchgear options. These switches are the predominant type installed in our 11kV cable distribution network.	4,723
	Ring-main unit (RMU)	These units are fully enclosed metal-clad 11kV switchgear. There are no oil insulated RMUs installed on the network. They typically have load-break switches and or vacuum circuit breakers. With motorisation and the addition of electronic protection relays they can be fully automated. They may be installed in a substation or outdoors. Since 2006, RMUs installed on the network have been rated for internal arc fault containment, which ensures a high level of safety in the rare event of asset failure.	163
	HV fuse (drop out)	HV fuse is commonly referred to as a drop out. It is a switch-like assembly containing either replaceable fuse elements, fuse links or solid links. The assembly is designed to 'drop out' the HV fuse link when the fuse element melts providing a visual fault indication or can be used as an isolation point.	8462
400V	Low voltage switch	Installed generally in distribution substations, these switches form the primary connection between 11kV/400V transformers and the 400V distribution network, giving isolation points and fusing capability using high rupturing current (HRC) links. All new installations are of the DIN type instead of the exposed-bus (skeleton) and V-type fuse design.	5,615

Figure 7.11.3 HV switchgear age profile



7.11.3 Asset health

7.11.3.1 Condition

Overall, our circuit breaker fleet is in good serviceable condition. Methods of condition monitoring, such as partial discharge detection and measurement, have enabled us to detect defects and make repairs prior to failure.

Some of the older 33kV and 66kV circuit breakers have multiple condition issues identified, such as corrosion, gasket and O-ring leaks, and damaged bushings. These issues are consistent with expected age-related deterioration given the nature of their outdoor environment and are being factored into our maintenance and replacement decisions.

Overall, our circuit breaker fleet is in good serviceable condition.

Figure 7.11.4 Subtransmission circuit breaker condition profile

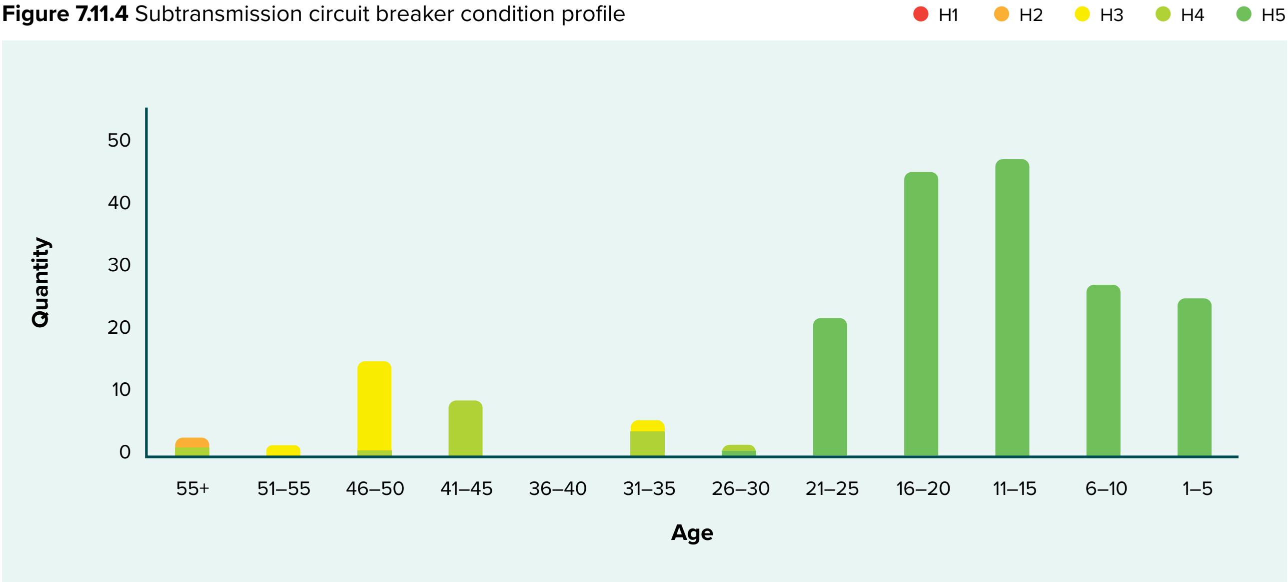
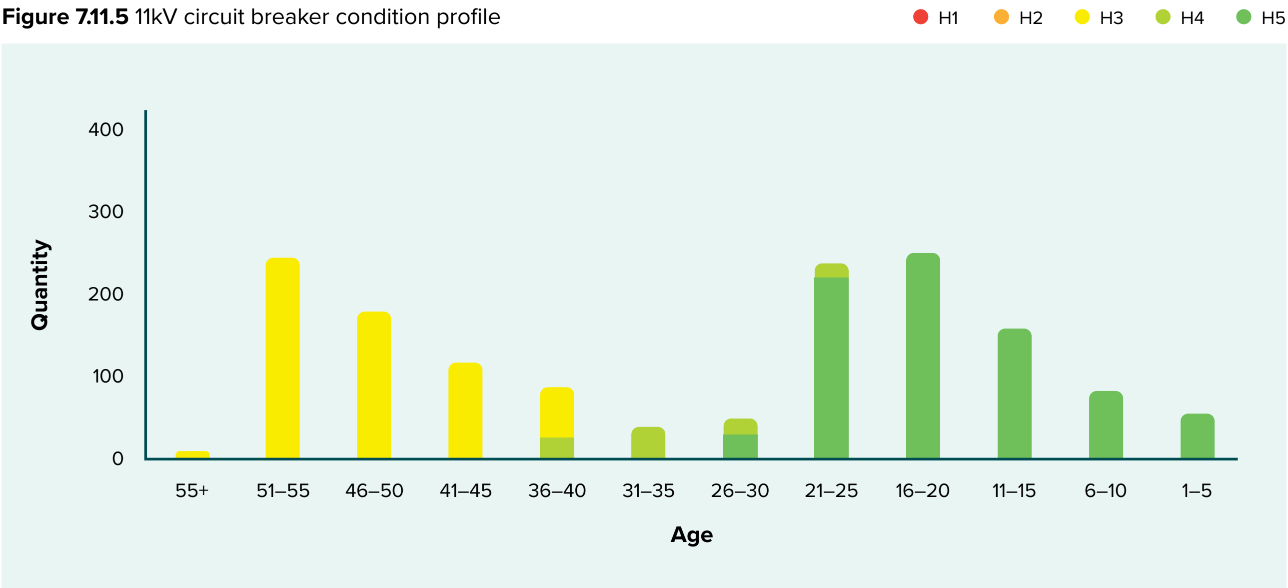


Figure 7.11.5 11kV circuit breaker condition profile



Most of our ring-main units are in a reliable condition; however, there is a known issue with a small portion of the fleet, which we are in the process of rectifying, see Table 7.11.5. Line switches are relatively new assets to the network and, so far, show no significant degradation or defects. The majority of our line ABIs are in serviceable condition, however some known issues exist, and some older types are approaching the end of their life.

A technical investigation on a sample of our MSU switchgear in 2020 helped us better establish their end-of-life criteria and expected lifespan. The MSU fleet was shown to be in suitable condition and still fit for purpose with maintenance. Our low voltage switches show no significant degradation or defects.

7.11.3.2 Reliability

Switchgear provides the capability to control, protect and configure the electricity network. A summary of our switchgear performance by type is shown in Table 7.11.5.

Table 7.11.3 Performance of switchgear

Voltage	Asset Type	Performance
66kV / 33kV	Substation disconnectors	Some older disconnectors are experiencing performance issues and have required servicing or repairs under emergency maintenance. We will replace problematic units in this AMP period through our replacement programme.
66kV / 33kV / 11kV	Circuit breakers	Our SF_6 circuit breakers are aging and with a few are beginning to leak due to deterioration of gaskets and O-rings. We have a maintenance programme to replace gaskets and Oo-rings for our SF_6 circuit breakers. Our aging oil type 11kV circuit breakers continue to provide reliable service, however failure of these assets, whilst rare, could be catastrophic, with the potential to cause injury to operators. Spare units and parts are becoming scarce for some models which is increasing the duration and cost of maintenance or repairs. We are for these reasons phasing out all oil-filled circuit breakers as they reach their end of life. We replace oil type 11kV circuit breakers with vacuum type circuit breakers rated for arc fault containment. These require minimal maintenance and meet modern performance, environment, and safety standards.
33kV	Line ABI	Our remaining line ABI's are routinely maintained and are performing as expected. These are progressively being replaced by line switches to provide improved reliability, reduced maintenance and to allow for remote control capability in preparation for a potential automated power restoration system.
11kV	Line switch	These are relatively new to our network, performing well and have no defects or lifecycle related failures to date.
	Line ABI	One model of ABI is exhibiting a high failure rate due to faulty insulators. There is a targeted replacement program to address this, finishing in FY26. We are phasing out ABIs and prefer to install line switches due to the remote operation capability and lower maintenance requirements.
	MSU	These units are ageing but have performed reliably. Failures are usually due to secondary factors such as a cable termination failure or contamination. On average there have been two failures per year. The failure rate has decreased slightly in recent years. The most common reasons for failure are due to corrosion and faulty contacts. Defects are identified by routine inspection and testing and rectified by either our scheduled or reactive maintenance programme We have identified a safety risk where unfused MSUs may contribute to prolonged clearance times for transformer and LV faults. We are addressing this issue through our replacement programme.
	RMU	A certain model of RMU installed on our network between 2014 and 2019 has a type issue, resulting in a number of these units experiencing internal phase to earth faults. We are working with the manufacturer on the issue and will be addressing high risk sites in our replacement plan. The rest of the RMU fleet is performing well and they are reliable with very few minor defects reported, which are dealt with in our reactive maintenance programmes.
400V	HV fuse (drop out)	The overall performance level for our drop out fuses is satisfactory. It is our largest assets class for overhead switchgear and has good reliability for the size of the fleet.
400V	Low voltage switches	The older 'skeleton' type panels and switches have good electrical performance, however, exposed busbars create safety risks and are not consistent with modern safety standards. We have mitigated this risk by installing additional barriers to reduce the likelihood of inadvertent contact. Some issues have become apparent with DIN type switches. These have generally been related to overheating created by the quality of connection and installation. We are addressing these in our maintenance programme and also targeted replacement of our older exposed bus type where the opportunity arises.

7.11.3.3 Issues and controls

Switchgear failures are rare, but when they occur, it can cause significant disruption to our customers and pose a significant safety risk to our people and service providers. Table 7.11.4 lists the common causes of failure and the controls we have implemented to reduce the likelihood and consequences of these failures. These controls enable us to maintain a safe, reliable, and resilient system, and help protect the environment.

Table 7.11.4 Switchgear failure controls

Common failure cause	Known issues	Control measures
Insulation deterioration or loss of insulant deterioration	Aging insulation such as deterioration of epoxy or resin bonded paper, moisture ingress and loss of or deterioration of insulant (both oil and SF_6). Insulation failure can be catastrophic and potentially damage nearby assets, particularly for oil insulated assets where the risk of fire is increased. Poses a risk to staff where manual operation of switchgear is required.	Partial discharge testing, monitoring. Routine maintenance. Replacement if ongoing maintenance and refurbishment is not economical or not possible.
	Internal flashover has occurred on a small number of RMUs manufactured by a single manufacturer between 2014 and 2019.	We no longer install this model of RMU and have changed our operating procedures to minimise the risk of further failures. A proactive replacement program to address high risk sites will take place over this AMP period.
Breaker contact surface degradation	Oil circuit breaker contacts are prone to wear, particularly during fault operations. This can lead to high resistance heating of contacts, damaging the insulation and eventually failure. MSU contacts in coastal areas are particularly susceptible to corrosion.	Oil circuit breakers are maintained after fault interruption. Heaters are installed to prevent condensation. Targeted maintenance programme for coastal sites. Parts replacement/refurbishment if possible or economical.
Cable termination degradation	Aging and partial discharge from inadequate clearance, condensation and contamination and poor-quality terminations.	Partial discharge testing and monitoring. Routine maintenance, cleaning, repair and/or termination replacement.
Mechanical failure	Stiction of mechanism from prolonged inactivity. Degradation of lubricant, aging, wear and fatigue.	Routine maintenance to prevent failure. Repair if economical and spares available. If not, then replacement. Use of modern long-life lubricants.
Pests and vermin	Bird strikes on outdoor circuit breaker due to insufficient clearances	Planned replacement and design for sufficient clearances.

7.11.4 Maintenance plan

We use both time-based maintenance - scheduled maintenance - and reactive - non-scheduled maintenance - for our circuit breakers and switchgear. Scheduled maintenance and inspections programmes apply to all assets in this category. Our non-scheduled maintenance programme is additional inspection, testing and maintenance work targeted at assets with poorer condition or reliability to maintain their performance and mitigate against failure. For in-service failures or defects that present an immediate risk of interruption or a safety risk we conduct emergency maintenance. Our inspections and maintenance are conducted at intervals as shown in Table 7.11.5.

For in-service failures or defects that present an immediate risk of interruption or a safety risk we conduct emergency maintenance.

Table 7.11.5 Switchgear maintenance plan

Asset type	Description	Inspection frequency	Maintenance interval
MSU	Scheduled inspection – check heater operation, signs of PD, dust covers fitted. Report defects or contamination found.	6 months	As required
	Scheduled maintenance – MSUs near the coast are routinely maintained to remove surface contamination and corrosion.		4 years
RMU	Inspect and report defects.	2 months (zone substations) 6 months (distribution network)	As required
ABI	Scheduled maintenance – clean, inspect and lubricate moving parts and contacts. Clean insulators, inspect terminations.	–	5 years
Disconnectors	Scheduled maintenance – clean, inspect and lubricate moving parts and contacts. Clean insulators, inspect terminations.	–	4 or 8 years
400V LV switches	Scheduled inspection – visual inspection, and defect rectification.	Substations – no more than 6 months All other LV – no more than 5 years	As required
	Scheduled inspection – inspect andv report defects.	2 months (Zone) 6 months (Distribution)	–
Circuit breakers	Non-intrusive survey of equipment using online partial discharge detection methods to identify insulation defects.	Variable based on age, criticality and defect history of the asset	–
	Scheduled maintenance – clean and lubricate moving parts, repair or replace contacts, tripping tests, electrical diagnostic tests, service or replace oil.	–	4 or 8 years
Line switches and reclosers	Scheduled maintenance – exterior and control relay are inspected annually.	12 months	8 years
	Our SCADA provides initial indication of problems.		

Our operational expenditure forecast is based on historical costs of maintenance and repair. The assumptions for our forecast are:

- The volume of assets will remain approximately constant over the forecast period, which already accounts for any additional inspection and surveillance of our older circuit breakers and switchgear.
- The failure rate will remain constant.

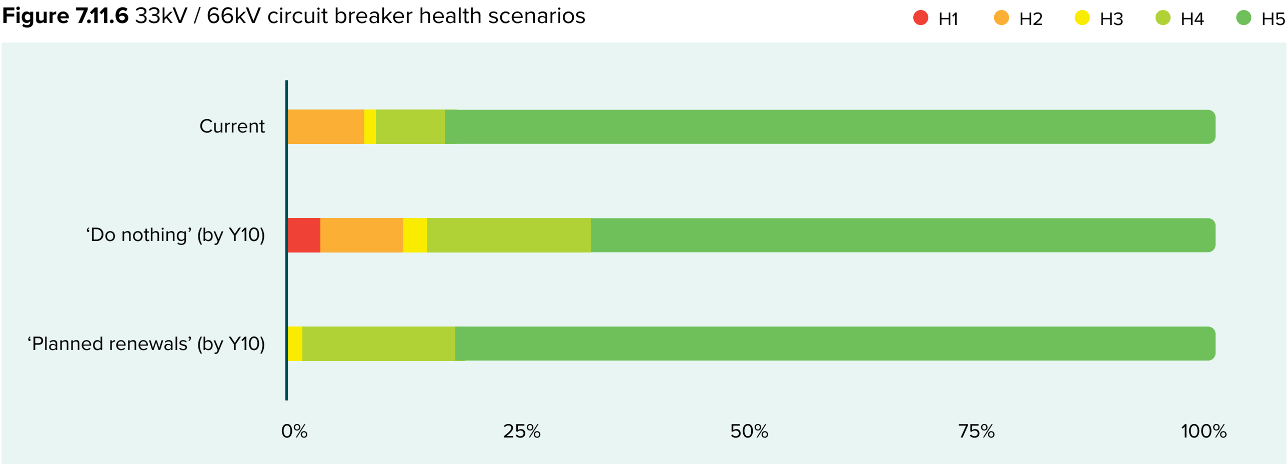
7.11.5 Replacement plan

We have a proactive replacement plan for our switchgear that is based on our assessments of condition, criticality and risk. Condition is based on a combination of age, condition data where available, known type specific issues, operating history and ongoing supportability. Consequences consider the potential impact on safety, customer service levels, environmental harm and cost. For some asset sub-classes we utilise CBRM models to assist us with processing condition and criticality data to reach our assessments of risk and renewal priority.

66kV / 33kV circuit breakers

We analyse different scenarios / options for the replacement programme to look at their impact on risk profiles. We compare the health index profiles of the 66kV and 33kV circuit breakers today with that expected upon completion of the 10-year replacement and the 'do nothing' scenario, see Figure 7.11.6.

Figure 7.11.6 33kV / 66kV circuit breaker health scenarios



- **'Do nothing' scenario –** as a means of comparison, we show the counterfactual 'do-nothing' scenario where no circuit breakers are replaced. This shows that without investment a significant proportion of the subtransmission circuit breaker fleet would be at health grade H1 or H2 and would no longer be safe to operate or reliable in service. The do-nothing scenario provides us with a benchmark that we use to assess the benefits of the planned renewal scenario.
- **'Planned renewal' scenario –** shows the circuit breaker health profile we anticipate will result from our proposed investment programme. Our current investment programme is designed to ensure we replace all circuit breakers before their end of life and generally improve the health profile of this critical asset class. The planned renewal health profile also includes asset replacement driven by network growth.

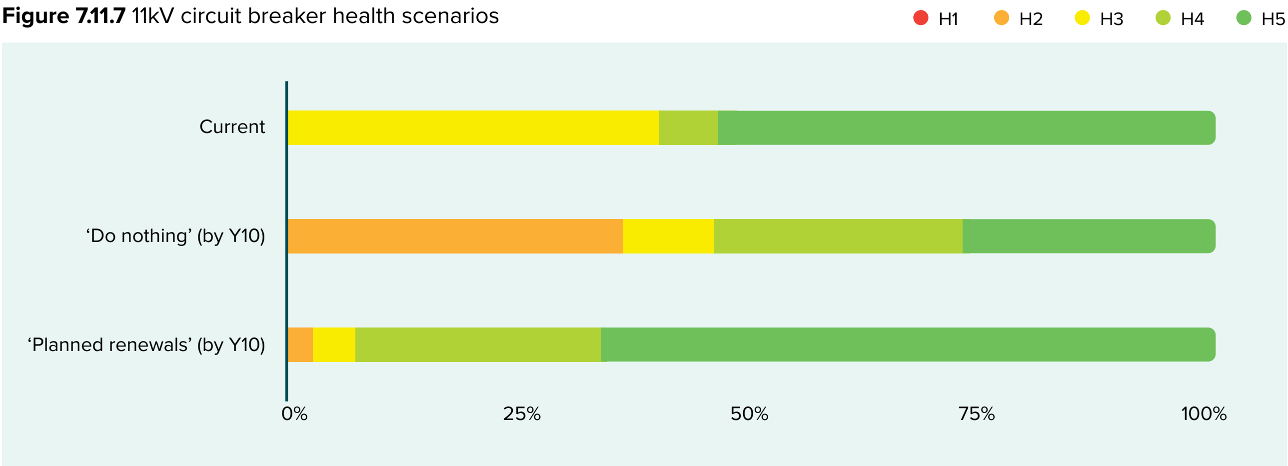
11kV circuit breakers

Figure 7.11.6 compares the health of our current versus planned future 11kV circuit breaker fleet. The modelling shows we will have a large population of older oil filled circuit breakers reaching end-of-life over the AMP period. These are split 35% in zone substations and 65% in distribution substations. Their replacement is an appropriate response to minimise the potential safety and operational risks associated with ageing 11kV circuit breakers.

During FY24 we completed 11kV circuit breaker replacement at Heathcote zone substation.

In FY25 we will complete 11kV circuit breaker replacement at our Hawthornden zone substation and commence 11kV circuit breaker replacement at our Barnett Park zone substation. We also have an ongoing circuit breaker replacement programme for our distribution substation circuit breakers. These are usually replaced with RMUs or MSUs as modern secondary switchgear can provide the required functionality at lower cost.

Figure 7.11.7 11kV circuit breaker health scenarios



66kV / 33kV substation disconnectors

For these assets, we model condition and risk scenarios with CBRM. Older wedge type disconnectors can have alignment issues, so we are prioritising replacement of these to improve operational performance.

33kV line ABI

Our small population of 33kV ABIs are progressively being replaced by line switches. Replacement is based on their condition and criticality, and we expect to have replaced all our 33kV ABIs by FY28.

11kV line ABI

As ABIs reach their end of life we are replacing these with vacuum line switches due to their superior reliability, lower maintenance requirements, safer operating capability, and the ability for remote operation and fault detection which can improve restoration times.

11kV switches

MSU replacement is based on a combination of age and risk. The age-based replacement strategy targets MSUs that are near end of their maximum service life and our risk-based replacement targets unfused MSUs that may not always ensure adequate clearance times in the event of a substation low voltage busbar fault. We will replace a third of the unfused MSU fleet over the next ten years, targeting the oldest units first. The age-based replacement rate will need to increase over this AMP period as we see a significant number of MSUs reach end of life. Approximately 12% of our MSU fleet will reach end of life in the next 10 years.

Low voltage switches

Some of the older exposed bus type LV switches associated with unfused MSUs have been identified where the low voltage arc flash incident energy presents a hazard. We have a targeted programme to replace these units to mitigate the risk. Other LV switches that are end of life will be replaced as part of the switchgear renewal works. Most skeleton LV panels are at sites with aging or end of life MSUs, and we anticipate an increase in LV panel replacements as we replace more end of life MSUs.

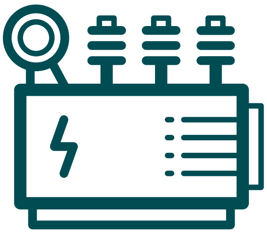
For switchgear assets where CBRM models are used, we take a bottom-up approach to forecasting capital expenditure. While past costs can be helpful for predicting future costs for simple replacement programmes, we find that a more thorough, site-by-site analysis is needed for more complex projects. This involves looking at different engineering options and developing business cases to arrive at a more accurate forecast of capital expenditure.

7.11.5.1 Disposal

Our Hazardous Substances procedures detail the disposal requirements for substances such as switchgear oil.

These procedures also mandate the prompt reporting of any uncontained spillage and disposal of hazardous substances, which allows us to document the details of spillage and disposal quantities.

We also have procedures for the environmental management and disposal of Sulphur Hexafluoride (SF_6).



Our power transformers installed at zone substations range from 2.5MVA to 60MVA.

7.12 Power transformers

7.12.1 Summary

Power transformers are high value, critical, long lead time network assets that are required to deliver reliable supply. Their failure has the potential to impact many thousands of customers, and it is important they are appropriately maintained. We have forecast to refurbish several ageing power transformers over the AMP period to extend their reliable service further. Our oldest transformers are ex-Transpower single phase transformers which we plan to replace in this AMP period due to their age and condition.

Our oldest transformers are ex-Transpower single phase transformers, which we plan to replace in this AMP period due to their age and condition.

Our asset management objectives for this asset class are:

- Achieve target levels of system reliability, availability and security.
- Provide voltage regulation within regulated limits.
- Operate safely with no serious events involving employees, contractors, or the public.
- Prevent uncontrolled oil spills.
- Provide resilience following a significant environmental or seismic event.

7.12.2 Asset description

Power transformers are installed at zone substations to transform subtransmission voltages of 66kV and 33kV to a distribution voltage of 11kV. They are fitted with on-load tap changers and electronic management systems to maintain the required delivery voltage on the network. All our transformer mounting arrangements have been upgraded to current seismic standards, and all transformers have had a bund constructed to contain any oil spill that may occur.

Table 7.12.1 Power transformer quantities by type

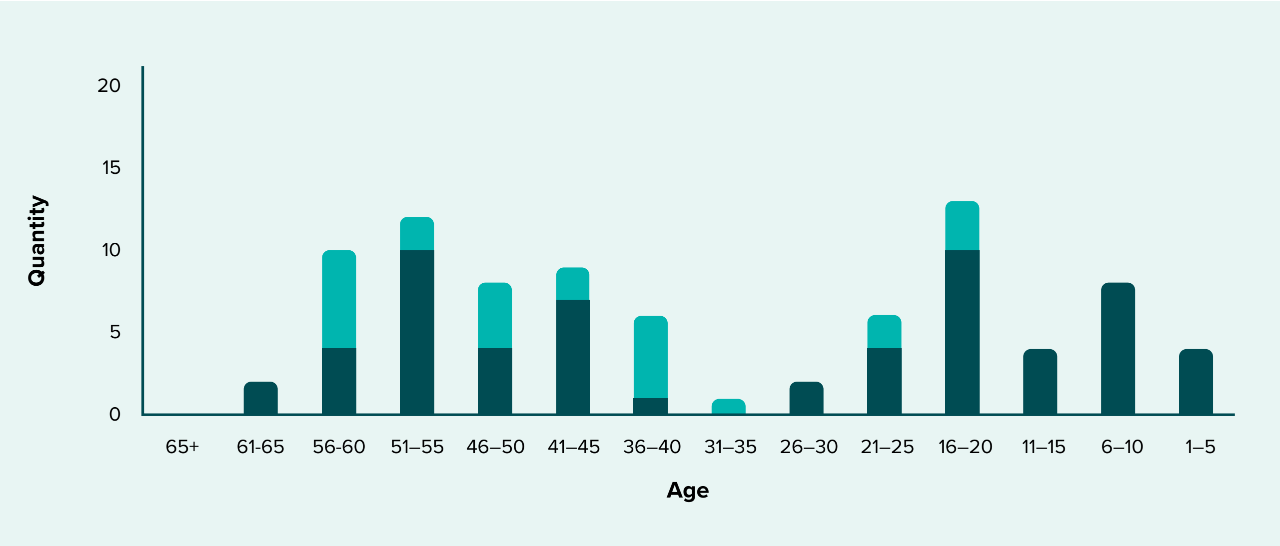
Nameplate Rating MVA	66kV	33kV
	Quantity	Quantity
30/60	2	
34/40	2	
30/36 (1Ø Banks)	2 (6)	
20/40	29	
20/30	2	
11.5/23	13	7
10/20		3
7.5/10	6	8
7.5		6
2.5		1
Total	**56 (60)**	**25**

Our power transformer age profile is shown in Figure 7.12.1. The useful life of a transformer can vary greatly depending on design construction and historical in-service loading. As most of our transformers are part of an N-1 redundant system, they typically operate well below their nominal capacity. This lengthens their effective operating life.

We test and maintain our power transformers annually to assess their condition and ensure satisfactory operation.

Some of our transformers are also refurbished where economically viable, which involves replacement or refurbishment of ancillary equipment and painting to ensure we achieve the expected asset life of at least 60 years. Some of our older transformers are scheduled for replacement later in this AMP period, see Section 7.12.5.

Figure 7.12.1 Power transformer age profile

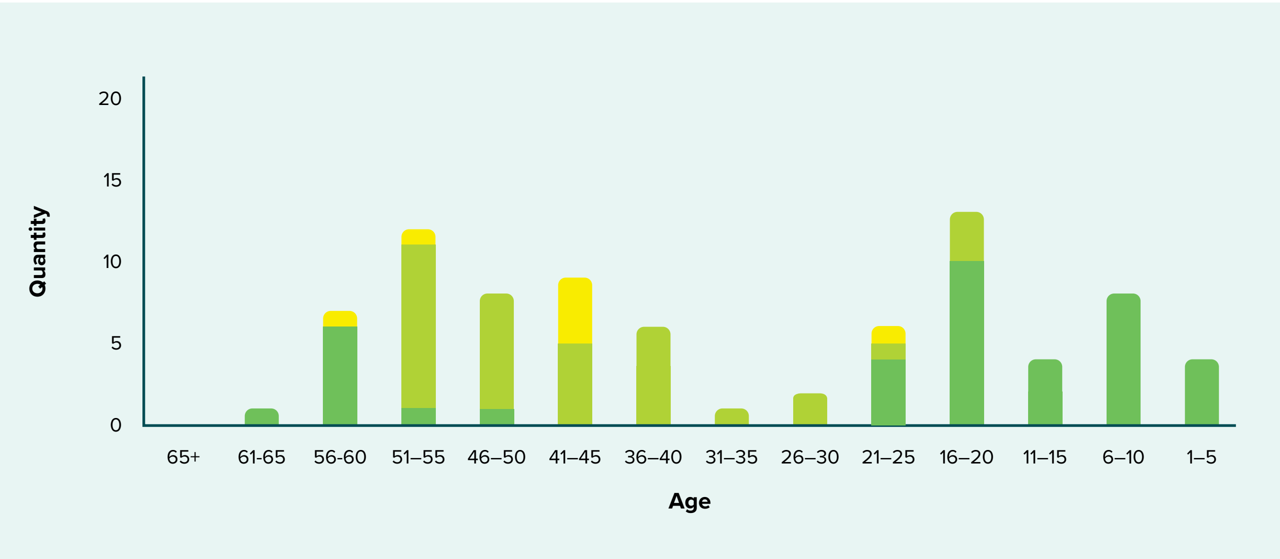


7.12.3 Asset health

7.12.3.1 Condition

Our inspection and maintenance programme informs us that most of our power transformers are in good serviceable condition with some approaching end of life. Some of our older transformers have issues such as moderate oil leaks and external condition deterioration. For our strategy to address these issues, see Sections 7.12.4 and 7.12.5.

Figure 7.12.2 Power transformer condition profile



7.12.3.2 Reliability

We design our system for N-1 power transformer redundancy in most situations and plan to attain a high level of reliability and resilience from this asset. The contribution of SAIDI from these assets is very low and the availability is high indicating that broadly, our current inspection, maintenance, and renewal strategies are effective. We continue to assess defects and failures to continually improve our maintenance practices.

7.12.3.3 Issues and controls

Table 7.12.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

We design our system for N-1 power transformer redundancy in most situations and plan to attain a high level of reliability and resilience from this asset.

Table 7.12.2 Power transformer issues and control measures

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Transformers are normally operated substantially below their maximum thermal capability. Transformer temperatures are monitored. Testing of oil in the transformer is used to determine paper degradation. New transformers have thermally uprated papers allowing higher operating temperatures and longer life.
	Moisture	Regular monitoring of the moisture in the oil and removal of moisture where identified (Trojan machine).
	Lightning	Surge arrestors fitted where appropriate.
Mechanical failure	Tap changer	We specify vacuum tap changers for new power transformers as they are essentially maintenance free Non vacuum tap changers are regularly maintained.
Material degradation	Corrosion	Routine inspections and maintenance programme. The tank and cooling fins are repainted as part of the refurbishment programme.
	Deterioration of enclosure gaskets can lead to moisture ingress	Gaskets are replaced in refurbishment programme.

7.12.4 Maintenance plan

Our maintenance activities shown in Table 7.12.4 are driven by a combination of time-based inspections and reliability centred maintenance.

Table 7.12.3 Power transformer maintenance plan

Maintenance activity	Strategy	Frequency
Inspection	Minor visual inspection and functionality check	2 months
Shutdown service	Detailed inspection and functional check	Annual
Oil diagnostics	DGA and oil quality tests	Annual
Oil treatment	Online oil treatment to reduce moisture levels	2 years or more often as required
Tap changer maintenance	Intrusive maintenance and parts replacement as per manufacturer's instructions	4 years for oil 8 years for vacuum
Level 1 and 2 electrical diagnostics	Polarisation index and DC insulation resistance DC Winding resistance, winding ratio test	4 or 8 years

Transformer refurbishment

We conduct half-life maintenance on power transformers wherever it is economically viable. This maintenance aims to extend the transformers' working life, enhance reliability, and defer the need for replacement. The programme involves a comprehensive workshop teardown of the transformer, refurbishment or replacement of the tap-changer and ancillaries, repainting the exterior, replacing gaskets, and removing moisture from and retightening the internal core. In the AMP period, we will undertake the refurbishment of 10 power transformers.

Our operational expenditure forecasts are based on assessments of transformer age, condition, and technical and financial feasibility.

We conduct half-life maintenance on power transformers wherever it is economically viable.

7.12.5 Replacement plan

Our current replacement programme is shown in Table 7.12.4. It is designed to maintain failure rates and risk at current levels.

Table 7.12.4 Power transformer replacement plan

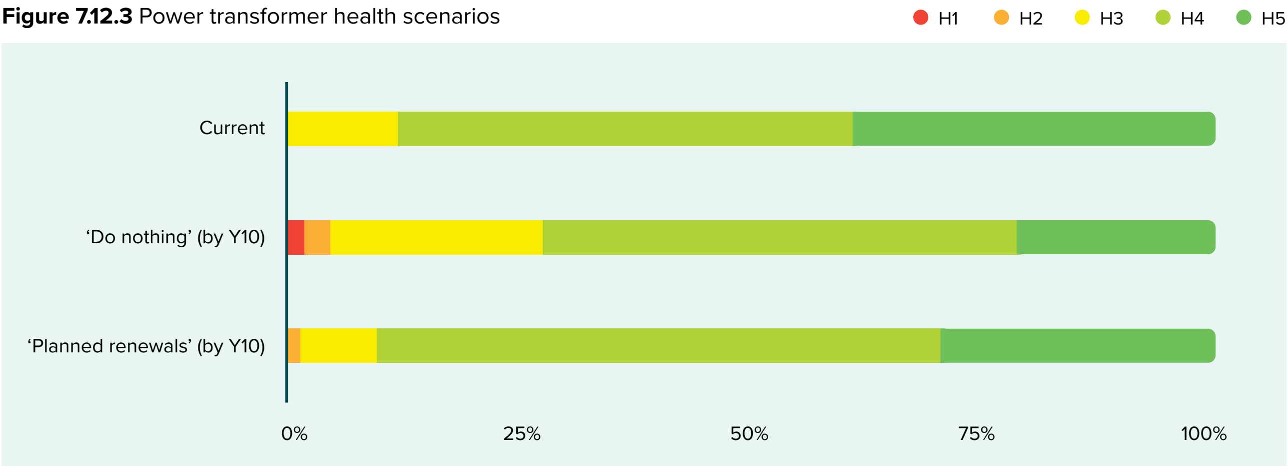
Zone substation	Details	Financial year planned
Addington	The T6 and T7 transformer banks, manufactured in the 1960s, have reached the end of their useful lives. Elevated moisture levels within the insulation and gassing issues in two of the single-phase units suggest potential faults. We are actively monitoring these issues, and if necessary, replacement can be done with spare units available for contingency in case of failure. Our strategy is to replace the aging and obsolete single-phase units with 3-phase units. This replacement initiative aims to enhance reliability, reduce maintenance requirements, and streamline our spare parts inventory.	FY28/FY29

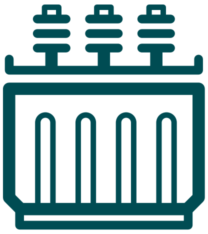
Figure 7.12.3 shows the current condition and 10-year condition projection for the two scenarios. 'Do nothing' is a hypothetical scenario where no transformers are proactively replaced or refurbished. This counterfactual scenario is provided as a benchmark to assist in visualising the benefits of the proposed programme. The 'planned renewals' is a targeted intervention that takes into account the asset's condition and the timing of other related works to produce efficient and economic outcomes.

Figure 7.12.3 demonstrates that the 'planned renewals' scenario ensures the fleet remains free of higher risk (H1 or H2) transformers. However, in the 'planned renewals' scenario, there is an increase in late-life H3 transformers, consistent with the age profile of the fleet. These will be managed through monitoring and maintenance, and if condition indicators deteriorate, some additional, un-forecasted interventions may be necessary within the AMP period.

Comparison with the 'do-nothing' scenario reveals that the proposed programme removes the highest-risk transformers from service.

Figure 7.12.3 Power transformer health scenarios





We have more than 12,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections.

7.13 Distribution transformers

7.13.1 Summary

We have more than 12,000 distribution transformers installed on our network to convert the voltage from 11kV to 400V for customer connections. Approximately 10% of our distribution transformer fleet is more than 55 years' old and 16% will become more than 55 years' old in the during next AMP period. To maintain our current reliability, we have forecasted more expenditure for proactive transformer replacement over this AMP period. We have also allocated capital expenditure in FY28 and FY29 for end-of-life replacement of our oldest voltage regulators.

Our asset management objectives for this asset class are:

- Provide reliable service to meet customer expectations.
- Operate safely with low risk to persons or property.
- Prevent release of oil to the environment.

7.13.2 Asset description

We operate two distinct types of distribution transformers along with a variety of voltage support assets.

7.13.2.1 Pole-mounted transformers

Typically used in our overhead network, pole-mounted transformers range in size from 15kVA to 300kVA. Most are single or three-phase types, but we also have a small number of Single Wire Earth Return isolation transformers used in remote rural areas. Due to seismic structural limitations, we now limit the size of pole-mounted transformers to no more than 200kVA.

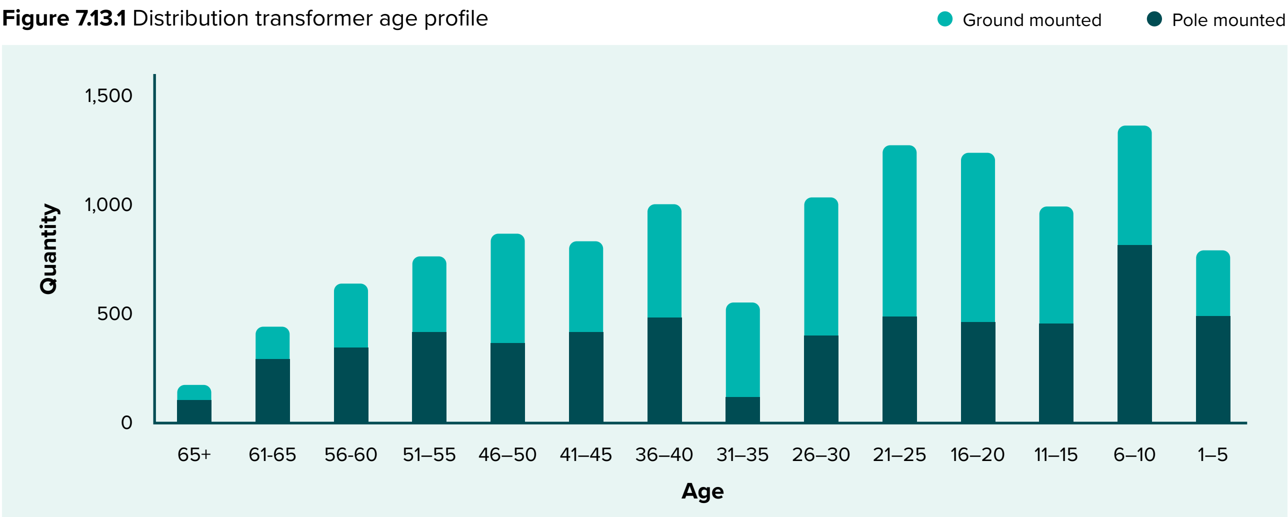
7.13.2.2 Ground-mounted transformers

Ranging in rating from 5kVA to 1,500kVA, ground mounted transformers are installed either outdoors or inside a building/kiosk. See Table 7.13.1 for our transformer quantities categorised by rating, for an age age profile, see Figure 7.13.1.

Table 7.13.1 Distribution transformer quantities by type

Rating kVA	Ground mounted quantity	Pole mounted quantity
5-100	570	5,938
150-500	4,419	380
600-1000	634	
1250-1500	32	
Total	**5,655**	**6,318**

Figure 7.13.1 Distribution transformer age profile



7.13.2.3 Voltage support

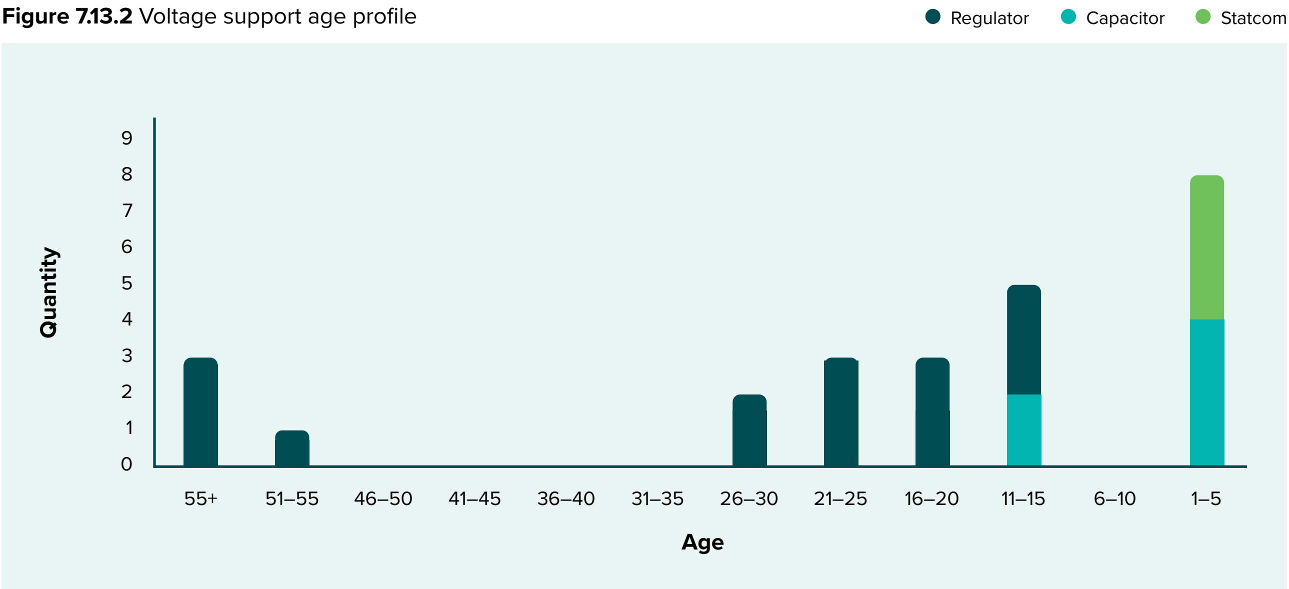
111kV line voltage regulators are installed at various locations to increase capacity where limited by voltage constraints. We utilise a wide range of ratings to accommodate different load densities within our network. All regulators are oil filled, with automatic voltage control through an on-load tap changer.

Additionally, we have other assets that provide reactive voltage support, including capacitor banks and Static Synchronous Compensators (Statcom). Statcoms can offer a continuously variable voltage support response. Table 7.13.2 displays the quantities of voltage support assets categorised by rating, while an age profile can be found in Figure 7.13.2.

Table 7.13.2 Voltage support assets quantities by type

Asset type	Rating	Quantity
Regulator	1,000 – 4,000kVA	12
	20,000kVA	3
Voltage support capacitor	500 – 750VAr	6
Statcom	2,500kVAr	4

Figure 7.13.2 Voltage support age profile



7.13.3 Asset health

7.13.3.1 Condition

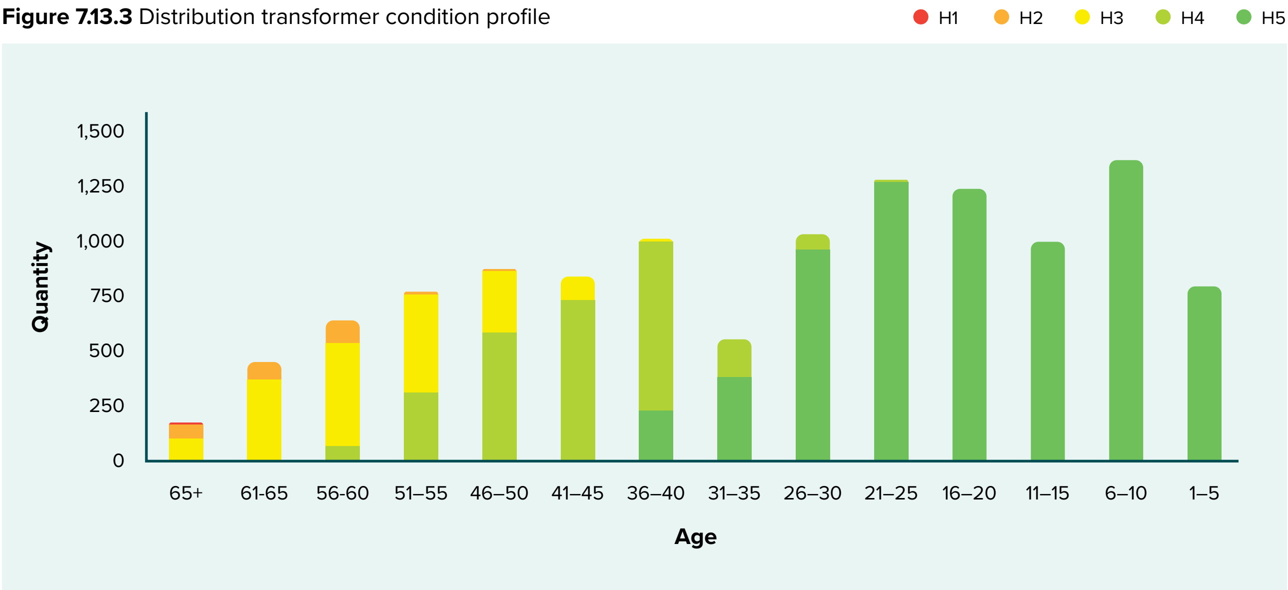
Distribution transformers

Figure 7.13.3 shows the age and health indicator profile for our distribution transformer fleet. The fleet is generally in good condition, with only a small proportion of the fleet classified as H2. This is to be expected because distribution transformers are maintained or replaced based on their condition for mid-size and large units and on condition or failure for small, low-consequence units.

Regulators

We have three 20MVA regulators located at Heathcote zone substation that are not required during normal operation but are kept available for contingencies that require voltage support to Barnett Park zone substation and to a lesser extent - Lyttleton township. These regulators are more than sixty years old, are in fair to poor condition and manufacturer and spare parts support is scarce. Since the Lyttelton Cable reinforcement project was completed in 2019, our reliance on two of these units has been greatly reduced, making them available for spare parts if necessary. There are no plans in the near term to replace any of the Heathcote regulators.

Figure 7.13.3 Distribution transformer condition profile



7.13.3.2 Reliability

The failure rate and contribution to SAIDI / SAIFI by distribution transformers is very low which indicates that broadly, our current inspection, maintenance, and renewal strategies appropriate for meeting our objectives.

7.13.3.3 Issues and controls

Pole-mounted transformers have a higher failure rate than ground-mounted transformers due to their constant exposure to the environment and more frequent exposure to lightning-induced voltage surges. Since it is uneconomical to routinely test and maintain pole transformers in service, and considering the low safety and customer impact consequences, running them to failure can be tolerated. Most of our ground-mounted transformers are regularly inspected and maintained as required. Table 7.13.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.13.3 Distribution transformer failure controls

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Maximum load of larger ground mount transformers are routinely checked and replaced if overloading occurs
	Lightning	Surge arrestors fitted at cable terminations to the lines protect ground mount transformers
Material degradation	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, maintenance and replacement programme
Ferro-resonance	Ferro-resonance refers to a power quality issue that can occur in a situation where lightly loaded 3 phase transformers on long cable feeders can create a voltage spike when one high voltage phase is opened. These voltage spikes have the potential to damage network and public electrical equipment.	To manage ferro-resonance, we install power factor correction capacitors phase to phase on the low voltage side of the transformer to swamp the cable capacitance to earth.

7.13.4 Maintenance plan

Our maintenance activities are driven by peiodic inspections and condition-based repairs. Ground-mounted transformers receive regular 6-month visual inspections, with the frequency largely driven by the need to ensure security and safety. Pole-mounted transformers are visually inspected as part of periodic overhead line inspections. Some minor maintenance is carried out on transformers which are readily accessible from the ground.

Distribution transformers are evaluated for refurbishment following removal from service for either loading reasons or repairable condition issues such as oil leaks or other minor damage or deterioration. They are assessed on a lifecycle costs basis with an expectation of providing a further 15 to 20 years of service without maintenance. This maintenance programme is shown in Table 7.13.4.

Table 7.13.4 Distribution transformer maintenance plan

Maintenance activity	Strategy	Frequency	
		Pole mount	**Ground mount**
Inspection	Visual inspection checking for damage to the transformer including cracked or damaged bushings, corrosion, unsecured covers, signs of oil leakage, paintwork. Minor repairs to ground- mounted transformers as necessary.	5 years	6 months
Maintenance	Maintenance as required.	As required	As required
Regulator	Detailed inspection and maintenance of internals. Inspect and maintain tap changer. Functional test of control circuits. Test insulation resistance test oil and treat for acidity and carbon build up.		6 monthly inspection 4 yearly maintenance
Capacitor banks	No specific inspection rounds. Maintenance as required.		As required
Statcom	Annual inspection and maintenance provided by manufacturer.		Annual maintenance

7.13.5 Replacement plan

Approximately 10% of our distribution transformer fleet is more than 55 years old. We forecast our expenditure on distribution transformer replacements will increase over the AMP period due to our age and condition profile. Expenditure has also been allocated to address known ferro-resonance over the next 10 years.

7.13.5.1 Disposal

Distribution transformers are recycled by approved recyclers to recover oil and metal components and safely dispose of those materials that cannot be recycled.

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults.

7.14 Protection systems

7.14.1 Summary

Our protection system assets are essential for the safety, security, and reliability of our network. Their primary function is to detect abnormal operating or fault conditions so that they can be interrupted by switchgear assets. Although they are comparatively low in cost compared to primary plant components, they have a significant impact on the performance and safety of our network, making them highly critical.

Our system consists of Intelligent Electronic Devices (IEDs) and electromechanical relays. Overall, our protection system equipment is performing well and meeting our service targets. The main issues stem from equipment aging or obsolescence in terms of support, parts, and functionality.

Protection system upgrades or replacements are most cost-effective when they are linked to projects that involve renewing or replacing the associated switchgear. Therefore, our protection system replacement program is influenced, and in some instances driven, by the schedule of our switchgear replacement.

Our objectives for this asset fleet are:

- Achieve high level of system performance by implementing and maintaining a reliable protection system.
- Detect and isolate faults quickly to minimise damage to network assets and prevent widespread outages.
- Ensure selective coordination of protection devices to isolate faults with certainty and avoid unnecessary disruptions to other parts of the network.
- Contribute to SAIDI/SAIFI by minimising network faults impact and duration.
- Ensure protection systems meets regulatory requirements and comply with safety and performance standards.

7.14.2 Asset description

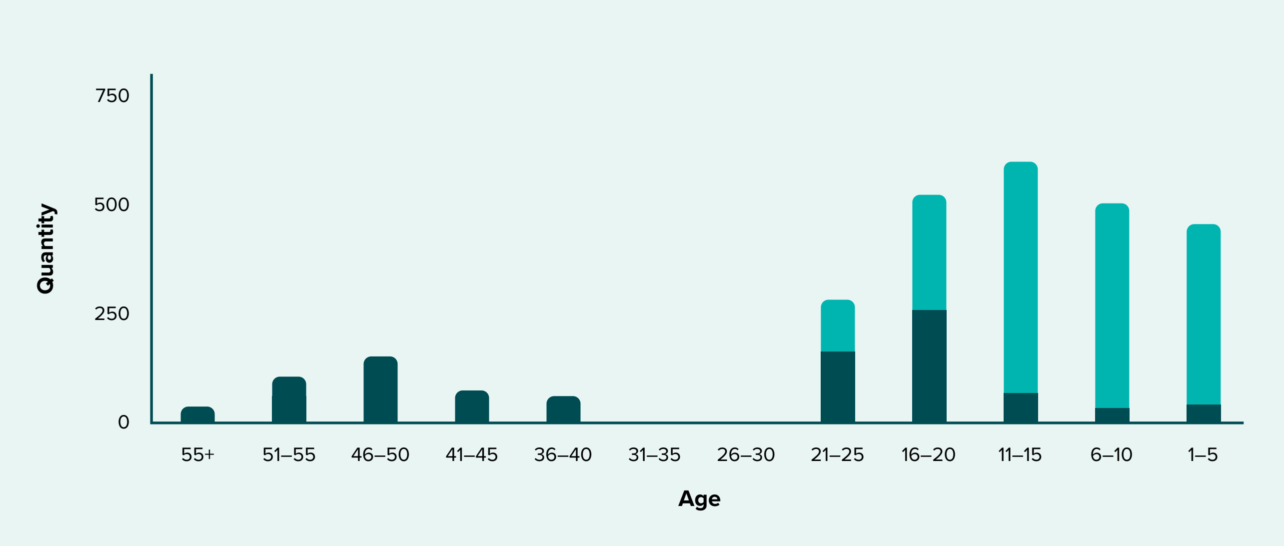
The protection relays we use on our network fall into one of two categories: electro-mechanical devices and microprocessor-based Intelligent Electronic Devices (IEDs). IEDs have become the most prevalent type, offering multiple functions such as protection, control, and metering, all integrated into a single device. The adoption of digital IEDs has enabled us to improve safety, enhance productivity, and improve system reliability and efficiency.

Electromechanical devices are legacy components typically installed with older switchgear. While generally reliable, they are now aging, are no longer supported by vendors, and possess limited functionality.

Table 7.14.1 Relay types

Relay type	Quantity
Electro-mechanical	1,012
Micro-processor based (IED)	1,792
Total	**2,804**

Figure 7.14.1 Protection relay age profile



7.14.3 Asset health

7.14.3.1 Condition

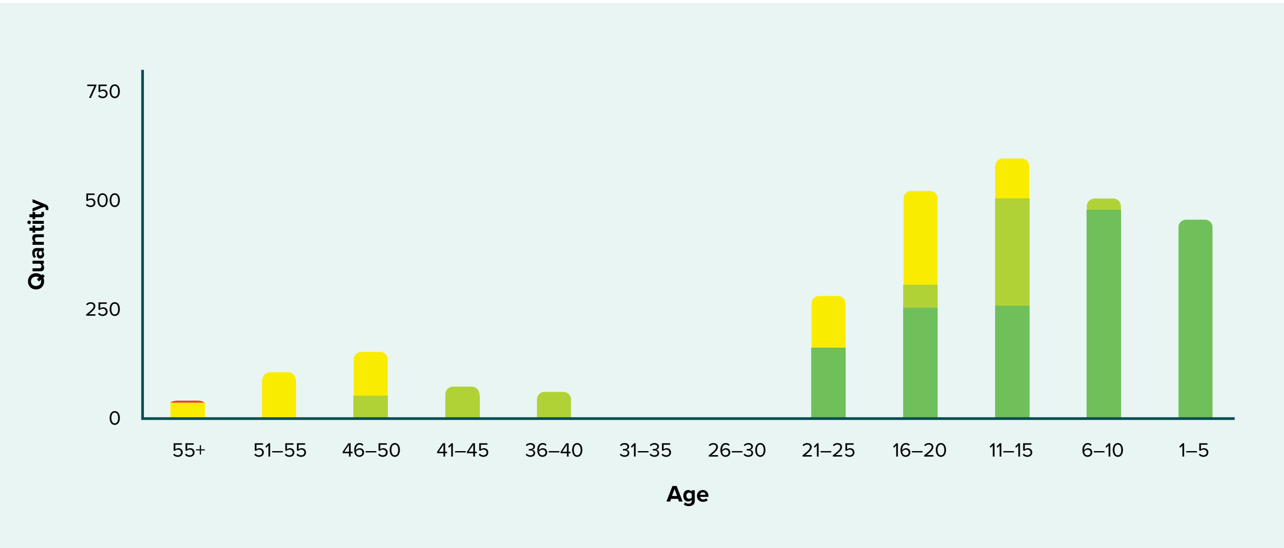
The health index for protection assets is predominately determined by age but modified to include our observations regarding variability by make and model and obsolescence and supportability factors. Figure 7.14.1 shows the health index profile against the age of our protection assets.

The health profile shows our protection relay population is in good, serviceable condition with most relays within their normal operating life. A smaller proportion of our population have health indices in the 'H3' range that while serviceable may be more prone to failure, requiring consideration for future replacement. A proportion of the H3 assets are ageing electromechanical types, which are typically installed alongside ageing switchgear. Where practicable we plan to replace these ageing protection assets with IED types in conjunction with switchgear replacement.

Another significant proportion of H3 protection assets are associated with electronic types in the 15-20 year age band. This reflects the often shorter life of some types of electronic equipment coupled with rapid obsolescence and withdrawal of manufacturer support.

We consider that the performance of our protection assets is meeting our asset management objectives and service level targets. The aim of our maintenance and replacement programme is to maintain our current asset condition and service levels.

Figure 7.14.2 Health index and age profile of protection assets



7.14.3.2 Reliability

Overall, Orion's protection systems are meeting our asset management objective to protect people and assets and to avoid unintentional outages due to protection system failure.

Our older electromechanical relays while lacking modern functionality are still performing satisfactorily to required standards. We restrict use of this ageing technology to short urban feeders that require relatively simple protection functions. The risks from failures are low due to these segments of the network having good backup supply and protection. However, as the associated switchgear comes to the end of its service life we take the opportunity to replace these relays with more advanced modern systems.

Overall, our Intelligent Electronic Device (IED) relays are performing well, but have a shorter service life than electromechanical types, with 15-20 years being considered normal. This is due to a range of factors such as failure modes of some electrical components, for example power supplies coupled with obsolescence of equipment, absence of vendor support for components or firmware, functionality and interconnectivity, and more recently cyber security risk.

7.14.3.3 Issues and controls

Protection failure can lead to longer fault durations with further potential for asset damage, larger outages with more customers affected and injury to our people and the public. Protection failure can also cause spurious tripping leading to unwanted isolation of circuits impacting our reliability. Table 7.14.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.14.2 Protection system failure controls

Common failure cause	Known issues	Control measures
Electrical failure	Ageing	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option.
	Loose wiring and termination	Regular inspection and testing.
Functional failure	Ageing and obsolescence	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option.
	IED hardware, firmware and software failure	Most IEDs are self-testing and SCADA monitored. Failures do not normally impact network reliability as repairs are carried out immediately under emergency maintenance. Repairs may be as simple as resetting the relay or replacing the failed components. Firmware upgrades can also resolve some known issues. Regular inspection can pick up non-SCADA connected relay issues.
Mechanical failure (especially electromechanical relays)	Ageing and obsolescence	Repair if economical and product still supported by manufacturer or spares available. If not, replacement is the only option.
	Vibration or drift out of set point	Regular testing and calibration.
Chewed cables	Pests and vermin	We have vermin proofed building entries and installed vermin traps in zone substations.

7.14.4 Maintenance plan

We carry out regular inspections of our protection systems including a visual inspection, display and error message checking and wiring and termination conditions. Protection systems are periodically checked for calibration and operation as part of the substation maintenance/testing rounds. The frequency of inspection and maintenance/testing of our protection system is dependent on asset location. The frequency of inspection and maintenance by location is shown in Table 7.14.3.

Table 7.14.3 Protection maintenance plan

Location	Task	Frequency
Zone substations	Inspection – check relay flags	2 months
	Protection testing	4 or 8 years
Distribution substations	Inspection – check relay flags	6 months
	Protection testing	8 years
Line circuit breaker	Inspection – check relay flags	Annual
	Protection testing	8 years
All 11kV trunk feeder sites	Unit protection testing	4 years

Based on analysis of failure rates and service provider costing, we forecast operational expenditure will slowly increase due to job callout volumes slowly increasing over previous years. This is due to an increasing shift toward IED relays and their self-monitoring systems initiating minor fault callouts.

7.14.5 Replacement plan

When we replace protection systems, we review options around the best device to use, their function, standardisation of design and how it fits into the immediate network.

Although we use the CBRM model to help guide our protection system replacement, a large portion of our relay replacements are still linked to our switchgear replacement programme. Replacement of protection systems in conjunction with end-of-life switchgear is economical and efficient in terms of cost and timing for outages. This is particularly true for our ongoing work of migrating our older electromechanical devices to modern IEDs. The timing for replacement of our older IED relays does not necessarily coincide with the associated switchgear as IEDs have a lifecycle of 15-20 years compared to a lifecycle of 50 years for switchgear.

Where 1st generation IEDs are due for replacement at zone substations we upgrade the protection to our current standards and install arc flash detection. This reduces the risk of asset damage and injury to our staff and service providers. The timing can also coincide with any other related work to be undertaken at those sites to reduce outages and more efficient usage of service provider resources.

Replacement of protection systems in conjunction with end-of-life switchgear is economical and efficient in terms of cost and timing for outages.

Our communication systems enable us to operate our network and deploy our people efficiently, and help us to reduce the impact of faults on customers.

7.15 Communication systems

7.15.1 Summary

Orion's communication network is made up of voice and data systems which provide crucial ancillary services essential to the operation and protection of our distribution network, and communication with our field staff, service providers and customers. These systems provide contact between our Control Room and operating staff and service providers in the field, protection signalling and remote indication and control of network equipment. Our communication systems enable us to operate our network and deploy our people efficiently and help us to reduce the impact of faults on customers.

These systems are in serviceable condition and performing well. Our transition from analogue radios to digital is well underway and will be completed in FY25. This will provide us with significantly increased signal coverage in remote areas of the network.

Additional capital expenditure has been put in place from FY28 onwards to strengthen our communication network across our operating region. These projects will provide safety benefits to our service providers by improving communication connectivity.

Communication systems support our asset management objectives by providing communication capability to field staff and real time monitoring and control of the network.

Our transition from analogue radios to digital is well underway and will be completed in the coming year.

Our objectives for communication system assets are:

- Contribute to service levels targets by operating voice and data communications efficiently.
- Facilitate protection signalling and monitoring for our control centre systems and engineering teams, aiding in operational and diagnostic tasks.
- Contribute to safety targets by providing fast and reliable communication for network operation.
- Establish seamless communication with field staff across our region, allowing for live conversations and delivery of documents such as operating instructions.
- Provide a reliable and efficient 'human' connection with our customers.
- Enable ongoing data collection to enhance understanding of the network, provide insights into network performance and support effective asset management.
- Maintain a reliable communication network that remains accessible to support critical network operations during challenging times.
- Be resilient and capable of providing required levels of service in foreseeable natural disaster events.
- Be secure and resistant to cybersecurity threats.

7.15.2 Asset description

7.15.2.1 Voice communication system

Our voice communication system is made up of three different sub-systems:

- **VHF analogue radio** – installed in vehicles and handheld portable units. These operate via Linked VHF hilltop radio repeaters. We will migrate these to digital once the backbone infrastructure is in place.
- **Private telephone systems** – we operate a high availability architecture with systems split between our Transportable Data centres with both connected to telco networks.
- **Public cellular networks** – not owned by Orion, we use these public networks for mobile voice and data communications.

  To increase resilience, our office cellular site and our Papanui cellular site are directly connected to the Christchurch cellular switching node.

7.15 Communication systems continued

7.15.2.2 Data communication system

Our data communication system is made up of five different network or sub-systems providing data communications to network field assets, protection signalling and general data communications to business mobile devices. These systems along with a description of each can be found in Table 7.15.1.

Table 7.15.2 shows the quantities of these assets by type.

Table 7.15.1 Data communication systems description

Asset	Asset description
Pilot cable network	Used for SCADA communication and protection signalling to urban substations.
SHDSL system	Used for point-to-point links and protection between substations utilising private copper communications where available. Various urban links are arranged in four rings to provide full IP communication redundancy to each substation. This system is fully protected against Earth Potential Rise (EPR) voltages.
UHF IP and protection radio system	Utilise high spectral efficiency radios operating in licensed UHF bands. These radios are used for point-to-point and point- to-multipoint where they utilise base stations located at hilltop sites.
Fibre communications system	Provide IP and protection signalling. Fibre is typically laid with all new subtransmission cables and provides high speed communications paths between our SCADA, engineering network IP and corporate office.
Public cellular network	Operated within a private access point name (APN) gateway provided by commercial providers. A number of our 11kV regulators, diesel generators, pole top switches and reclosers and various power quality monitors are connected to this system. This network also supports all our mobile devices and data connectivity to our vehicles.

Table 7.15.2 Communication component quantities by type

Asset	Quantity
Cable modems	349
Voice radios	400 (includes Orion service providers')
Cellular modems/HH PDA's	377
IP data radios	355
Radio antennae	355
Antenna cable	550
Communication masts	56
Routers/switches	56
Telephone switch	2

7.15.3 Asset health

7.15.3.1 Condition

Our IP based equipment is on average less than nine years old and is considered to be current and supported technology that is performing well. We have a programme in place to replace equipment that is nearing end of life.

Our copper multi-core communication cables are aging and are progressively failing with fault finding and repairs often uneconomic. A common failure point on the multicore copper twisted-pair communication cables is joints. These are expensive and difficult to troubleshoot and repair. Copper multicore cables are progressively being replaced by fibre and other communication channels.

7.15.3.2 Reliability

The SCADA IP network is reliable and can in many cases withstand multiple link failures without losing significant connectivity. This is because we have configured it in a mix of rings and mesh with multiple paths to almost all zone substations and major communications nodes. This diversity of connectivity is essential for ensuring ongoing capability in the event of a significant event such as an Alpine Fault earthquake.

7.15.3.3 Issues and controls

Table 7.15.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

Table 7.15.3 Communication systems failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Malicious damage (arson, shooting antennae). Weather damage (rain, wind, snow). Lightning strike. Power supply failures on radio units and base stations.	Resilient infrastructure and lifecycle management. Diversity of data/signal paths (rings). Open Shortest Path First (OSPF) routing protocol (functional self-healing). Spares.
	Human error.	Training / certification. Change Management.
Cable joint failure	These joints are epoxy filled and have two modes of failure, one due to epoxy used in the old filled joints overtime becoming acidic and eats away the crimp joints leaving the cables open circuited and another due to ground movement allowing moisture ingress due to the inflexible nature of the epoxy.	We routinely test circuits that are used for Unit Protection communication and any identified issues are addressed as part of protection maintenance at this stage.
Systemic failure	Interference from third party equipment.	Diversity of data/signal paths (rings). OSPF routing protocol (functional self-healing). Use of Licensed spectrum.
	Rogue firmware updates.	Device passwords. Change management / testing.
Cyber security threats	Because of the use of industry standard hardware and protocols, the external IP network is exposed to cyber security threats which include the possibility of unauthorised persons accessing the communication network from a substation and remotely operating, or modifying the settings, of equipment at other substations.	To mitigate this risk we have configured communication firewalls at zone substations and installed a centralised security system which logs and controls access to the network.
Reliance on public cellular providers	Our experience is that the public providers have different business drivers than our own when operating in a Disaster Recovery mode.	We closely monitor developments in private cellular network technology and other developments in this communication space.

7.15.4 Maintenance plan

Our electronic communications equipment is largely maintenance free and is repaired or replaced on failure. Failure consequences are generally low as equipment is monitored with faulty items being identified remotely and repaired quickly. Regular inspections of sites and functional testing are carried out to ensure reliable operation of the communication systems.

Table 7.15.4 Communication systems maintenance strategy

Asset	Maintenance activities / strategy	Frequency
Cable modems	Replaced if faulty, SHDSL modems are continuously monitored with faults attended to as soon as detected. The serial modems are being replaced by Ethernet SHDSL modems	As required
Voice radios	Replaced if faulty.	As required
Cellular modems / HH PDAs		
IP data radios	The performance of our UHF stations used to communicate with the SCADA equipment is continually monitored with faults attended to as soon as detected	As required
Radio antenna	Replaced if faulty, radio links are continuously monitored with faults attended to as soon as detected.	As required
Copper cables		
Antenna cable		
Communication masts	Visual inspection as part of substation inspection. Targeted inspections are performed on masts affected by the effect of winds in the lee of mountains, the lee air effect.	2 months Annually
Routers / switches	Replaced if faulty, links are continuously monitored with faults attended to as soon as detected.	As required
Telephone switch	We have maintenance contracts with several service providers to provide on-going support and fault resolution. A 24x7 maintenance contract for the telephone switch is in place.	Monthly

7.15.5 Replacement plan

Due to the rapid improvement in technology, communications equipment has a relatively short life with manufacturer support ceasing, leading to obsolescence. To cater for this our communication systems renewal programmes are planned using an age-based approach with the timing of programmes governed by projected asset obsolescence and reduction in the availability of spares and support.

Table 7.15.5 Communication systems replacement plan

System	Replacement plan
Completion of IP Network	We are progressively upgrading older analogue links when the associated network primary equipment is replaced. Additional IP radios were installed as part of protection improvements on the Banks Peninsula 33kV ring to provide alternative communication links to the Peninsula.
Voice radios	After the successful trial of a digital radio system on the Banks Peninsula in FY20, we are continuing to migrate our existing analogue system. The upgrade will significantly increase our coverage in remote areas and offer more safety features such as user identification and user location.
Comms architecture projects	As we introduce new assets and technologies on our network, the need for communications increases. Expenditure is allocated for such projects, with the majority going towards fibre installations. We have established a capital expenditure program aimed at expanding fibre connectivity in rural areas. Additionally, we are strategically coordinating fibre installations alongside other projects to reduce overall cost.
Control Centre voice communication systems	From FY25 we are upgrading voice communication systems used by our Operational Control Centre team and our Customer Support team. We are intending to deploy interoperability console technology in our Control Centre combining Digital mobile radio + Push to talk cellular + Conventional Telephony on a single device primarily offering flexibility call control and stacking instead of queuing. This will allow both teams to take advantage of specific evolving technology features.
Future projects	From FY28 onwards, we will roll out additional projects to strengthen our communication network across our region. These projects will provide safety benefits to our service providers by improving communication connectivity. The exact timing of these projects will be finalised as requirements become clearer to us closer to the time. Some of the proposed projects are: • More mobile bandwidth outside cellular coverage • Dual communications routes for major sites • Additional hilltop communication hubs

Safety is a core driver for the use and development of our data management systems.

7.16 Advanced Distribution Management System (ADMS)

7.16.1 Summary

Our Advanced Distribution Management System (ADMS) is a digital model of our high voltage network and supports a range of activities related to the operation, planning and configuration of the electricity network. Safety is a core driver for the use and development of our ADMS. It is an essential element in our efforts to ensure the safe and effective operation of the network.

Our ADMS enables automated control and management of our electricity network and directly supports the achievement of our reliability measures such as SAIDI and SAIFI. We also enabled Automatic Power Restoration System (APRS) technology in FY24 for parts of the network enabling the ADMS to automatically operate network equipment to self-heal, promptly restoring healthy network to customers following a fault.

The network model used by our digital ADMS and the Supervisory Control and Data Acquisition (SCADA) data it relies on is currently limited to high voltage assets of 11kV or more. Over the next five years we will extend the model to include low voltage assets. This will allow us to support changing customer energy use and an expected increase in Distributed Energy Resources (DER) technologies on our network.

The network model used by our digital ADMS and the data it relies on is currently limited to high voltage assets of 11kV or more. Over the next five years we will extend the model to include low voltage assets.

Our ADMS supports our asset management objectives by optimising network operations to deliver a more reliable, efficient, and safe electrical distribution network. Our objectives for Advanced Distribution Management System assets are:

- Improve the overall reliability of the network by reducing downtime and minimising service disruptions.
- Enable real-time monitoring and control of network assets to respond quickly in changing conditions and potential issues.
- Optimise the allocation of network resources, including load balancing, asset utilisation, and fault management, to ensure efficient energy distribution.
- Improve customer service by minimising outage durations and providing more accurate information during service disruptions.
- Ensure that the ADMS is adaptable to accommodate future technological advancements and network requirements.
- Enhance safety and security by implementing advanced monitoring and control features for the network.

7.16.2 Asset description

An ADMS is a suite of applications designed to monitor and control the distribution network, enabling decision-making and remote control by our Control Centre staff. Our future planning for our ADMS includes the installation of more remotely controlled switchgear and the use of the existing on-line load-flow analysis which enables the implementation of an Adaptive Power Restoration System (APRS). APRS allows the ADMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. This significantly reduces restoration times after faults occur on the network. Our future planning for our ADMS includes the installation of more remotely controlled switchgear and the use of load-flow analysis which will extend the implementation of the APRS to other parts of the network. We will also implement an online release request system to improve service provider workflow when accessing or switching our network.

Table 7.16.1 ADMS description

System component	Description
	Core systems
SCADA	A comprehensive SCADA master station is tightly integrated into the ADMS and provides telemetered real-time data to the network connectivity model.
Network management system (NMS)	At the heart of the ADMS is a comprehensive, fully connected network model (including all lines, cables switches and control devices, etc.) that is updated in real time with data from network equipment. The model is used to manage the network switching processes by facilitating planning and scenario development, applying safety logic and generating associated documentation. It also maintains history in switching logs.
Outage management system (OMS)	The OMS supports the identification, management, restoration and recording of all outage information. It assists in determining the source of interruptions by matching individual customer locations (from fault calls) to network segments and utilising predictive algorithms. Customer details are recorded against faults in the OMS which allows our Customer Support team to call customers back after an interruption to confirm that their power supply has been restored.
Mobile field service management	Network Operators are equipped with iPads and receive switching instructions from the Controller directly via the ADMS. The network model is immediately updated to reflect physical changes as switching steps are completed and confirmed on the iPad.
Remote terminal unit (RTU)	The remote terminal unit is a field device that interfaces network objects in the physical world with the distribution management system SCADA master station.
	Ancillary systems
Historian	The Historian is a database that records time series data for future analysis. The time series data stored in the historian is used by various applications throughout the organisation for planning, network equipment condition analysis and for reporting network operating performance statistics such as reliability.
Real-time load flow analysis	The ADMS has access to large amounts of real time field data and maintains a connectivity model making it possible to undertake near real time load flow calculations. Load flow analysis can be used to predict network operating conditions at locations where no telemetered data is available and can also carry out “what if” scenarios to predict the effects of modified network topologies and switching.
Information interfaces	Not all information required for operations and planning activities is available from the ADMS. Linking ADMS records to data from other systems greatly enhances our capabilities in both these areas. ADMS data may be presented in reports or used to populate web pages for internal or customer information.
Cyber risks	Cyber incidents are escalating for control systems around the world. Improved authentication, better access controls, improved segmentation of networks and systems, improved patching and upgrade practices are all essential to a safer control systems.

7.16.3 Asset health

7.16.3.1 Condition

Our ADMS is a critical system required to successfully monitor and control daily, real time network operations. The supplier releases a new software version every few months with new capabilities and bug fixes. We review our ADMS system annually and do a risk assessment on our current version with key considerations of maintaining system support, cyber security and enhanced capabilities offered by new releases. We will to do more regular updates to stay current with the latest functionality, security and usability features.

We have a number of older RTUs in our network that are no longer supported by their manufacturer. We hold enough spares to cover these units for maintenance purposes and they are performing adequately. These units are progressively being replaced as we undertake other upgrades at substations. The major RTU type used is at end of life and we are starting to replace them during substation maintenance rounds.

7.16.3.2 Reliability

Generally the ADMS system runs at or near 100% reliability. There are some constraints around the ADMS testing and development environments which are being addressed. This will improve our ability to test and trial changes to the ADMS and its associated modules, streamlining our upgrade path and improving system resilience.

7.16.3.3 Issues and controls

Our maintenance and replacement programmes are designed to ensure the continuous availability of the ADMS. This includes building highly resilient systems, upgrading core software and infrastructure on a lifecycle basis and undertaking regular reviews of system capacity and performance. Table 7.16.2 describes the potential failure cause and mitigation controls.

Generally the ADMS system runs at or near 100% reliability.

Table 7.16.2 ADMS failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Server hardware and platform failure	Real time monitoring, diversity, resilient infrastructure, lifecycle management
	RTU failure	Spares available Emergency contract
Information System (application/database) failure	Software failure / flaw	System monitoring, diversity, resilient platforms, maintenance contracts
Unexpected usage errors	Unexpected use cases	Training, testing, small systems change, upgrades

7.16.4 Maintenance plan

Our first line of support for ADMS software and infrastructure is provided by our own people. A maintenance contract with the software vendor includes:

- a remote response capability for emergencies
- a fault logging and resolution service
- the software component of any upgrade or service patch release

Our forecast expenditure is comprised of support contracts and licensing costs based on our current and future projections of enhancements.

6.17.5 Replacement plan

We made an Automated Power Restoration System (APRS) functional in our ADMS in FY24. We also plan to add a Primary Outage Restoration Tool (PORT) and Historic Network Viewer in the AMP period. These enhancements will deliver faster restoration following faults and post fault analysis of the event.

The capital expenditure in Table 8.16.4 supports our plans for major upgrades for our ADMS in FY25-FY27. The expenditure also allows for analytics, automated switching, an LV model and future capability to be integrated into the ADMS over the AMP period.

Our load management systems control electrical loads by injecting frequency signals over the electricity network.

7.17 Load management systems

7.17.1 Summary

Orion's load management systems allow us to control non-essential customer loads, such as hot water, irrigation, and street lights. This enables load deferral during peak times, reducing the need for asset investment. The load management system also provides a means to shed non-essential load during system contingencies, helping us maintain essential customer loads during such events.

The load management system comprises a range of hardware and software platforms, including some legacy assets that are no longer supported. Nevertheless, the load management system remains an integral part of our distribution system. We are in the process of upgrading our load management software and are taking the opportunity to integrate it within our ADMS system. This system will be fully functional in FY25. Our investment plan for this asset class includes refurbishing the hardware and software of the USI load management master station due to its age and the unavailability of system support.

Load management systems support our asset management objectives by lowering peak load using deferrable load control to improve the efficiency, reliability, and sustainability of our distribution network. The objectives for our load management system are:

- Implement load shedding or demand response plans to lower peak demand during high-load periods.
- Optimise network asset usage by effectively managing loads, prolonging the lifespan of equipment.
- Contribute towards SAIDI and SAIFI targets through load reduction during critical load periods by reducing the likelihood of power outages.
- Provide continual automation to manage aggregated load to a limit and control existing ripple plant accordingly.
- Ensure compliance with regulatory standards and mandates related to load management, grid operation, and energy efficiency.

7.17.2 Asset description

Our load management consists of two separate systems: Orion's load management system and the Upper South Island (USI) load management system, which Orion operates in collaboration with other electricity distributers in the upper South Island. These systems are described in Table 7.17.1.

The primary purpose of both systems is to defer energy consumption to reduce peak load. This is achieved by distributor-initiated signals to demand management relays at the customers premises which control interruptible loads such as hot-water and irrigation.

There are two ripple carrier frequencies used on our system. Consumer ripple relays are owned by the retailers, apart from approximately 2,000 street light control relays that are owned by Orion. Additional methods are also deployed to initiate load management for major customer loads.

We install new 11kV ripple injection plants in conjunction with new zone substations or rural zone substations that are converted from 33kV to 66kV.

7.17 Load management systems continued

Table 7.17.1 Load management systems description

System	Description	Quantity
Load management master station and RTUs	The load management master station is a SCADA system that runs independently of the network management system. This system is currently being replaced and integrated within our ADMS.	2 plus 1 spare
Upper South Island load management system (USI)	The USI load management system is a dedicated SCADA system run independently of our load management and network management systems. Two redundant servers take information from Orion, Transpower and seven other USI distributors' SCADA systems, monitor the total USI system load and send targets to the various distributors' ripple control systems to control USI total load to an overall target.	2 plus 1 historian
Ripple injection system Telenerg 175 Hz	This system operates mainly within our Region A network and is the major ripple injecting system controlling the load of approximately 160,000 customers.	27
Ripple injection system Zellweger Decabit 317Hz	The Decabit system operates predominately within our Region B network. The main reason for separate systems is the historical merger between distribution authorities and their separate ripple plant types.	17
Remote Terminal Unit (RTU) and load measurement	RTUs are used to gather information from load measurement points and consolidate totals for load management at substation levels. THE PQM and load transducers are required to accurately and reliably measure loads throughout the network.	50+ RTUs and 50+ PQMs

7.17.3 Asset Health

7.17.3.1 Condition

The condition of the load management system is described in Table 7.17.2.

Table 7.17.2 Load management systems condition

Asset	Description	Condition
Orion load management master station	The hardware and software have reached end of life, with no future support path provided by the manufacturer. Replacement is underway and expected to be completed in current AMP period.	Obsolete
Upper South Island load management system	This system was updated in late 2019. The system is maintained on a regular basis	Good
Ripple injection system – Region A 175Hz system	The majority of the 11kV injection plants were installed from FY04, and some components are approaching the expected useful life of 15 years. Historically, the units have been reliable and spare parts are available.	Poor
Ripple injection system – Region B 317Hz system	The 11kV and 33kV ripple plant injection controllers are approaching their expected service life. Historically, the units have been reliable and spare parts are available.	Poor
Measurements	The provision of resilient (i.e. redundant) load measurement is available at most sites but not all. Light sensing for accurate timing of street lights has only a single measurement point.	Good

7.17.3.2 Reliability

Overall, our load management systems are achieving the required load shedding performance required to maintain service levels and to limit tariffs. Few failures have occurred at peak times.

7.17.3.3 Issues and controls

Our maintenance and replacement programmes are developed to ensure the continuous availability of the load management system. The level of risk for this asset class is considered to be low as the consequences of non or mal operation do not typically result in loss of essential supply to customers. Table 8.17.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

Table 7.17.3 Load management failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Server hardware/platform failure	Real time monitoring, diversity, resilient infrastructure, lifecycle management.
	RTU and ripple plant failure	Spares available. Emergency contract. Operational switching of the network to manage loads or isolate faulty ripple plant if required.
Information system (application/database) failure	Software failure/flaw	System monitoring, diversity, resilient platforms, maintenance contracts.
Cyber risks	Known escalation in cyber attacks world wide	Patching / replacing with latest software to address known vulnerabilities.
Obsolesence risk	Software and hardware product end of life	Product lifecycle planning, vendor discussions.

7.17.4 Maintenance plan

We conduct an annual review of our master station system in collaboration with the supplier.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and comprehensive tests of the inverter system. Cleaning and physical inspections are also an integrated part of the annual maintenance. See Table 7.17.4.

Table 7.17.4 Load management systems maintenance plan

Asset	Maintenance activity	Frequency
Master station	Supplier review	Annual
Ripple plant	Shutdown clean, inspect and test	Annual

7.17.5 Replacement plan

Load management master stations

The load management master stations are critical for load control operations, and we undertake a risk assessment annually to consider the need for upgrades. In our assessment we look at current system health and availability of system support in coming years to continue to meet operational requirements.

We are upgrading our Orion load management system and after review of current systems and costs, we used this opportunity to integrate it with our ADMS system. This system will be fully functional in FY25.

The hardware and software of the USI load management master station is ageing, and the operating system will no longer be supported after FY26. This system is under review for refurbishment and/or migration plans.

Ripple plant and controllers

A replacement programme has been adopted to address asset obsolescence and non-availability of spares. We have had a proactive replacement programme for ripple signal controllers since FY23. The majority of these are now more than 16 years old and have reached the end of their operational life, leading to some age-related failures. While our ripple plant coupling cell equipment is replaced reactively we are exploring ways to be more proactive in the future as the coupling cells approach their end of life.

7.17.5.1 Disposal

The ripple plant parts that have been retired will either be used as emergency spares or recycled where possible, depending on their condition.

We are currently upgrading our Orion load management system and after review of current systems and costs, we used this opportunity to integrate it with our ADMS system.

Our maintenance plan has been effective in keeping our standby generators in good condition.

7.18 Generators

7.18.1 Summary

Orion uses mobile diesel generators to supply customers for short periods during fault repairs or planned interruptions. We also have emergency generators to provide supply to our building and other essential infrastructure to ensure continuity of capability in the event of emergency. To maintain a fuel supply for the generators we own diesel tanks and a mobile trailer tank.

Our maintenance plan has been effective in keeping our standby generators operationally ready and in good condition. We are not planning to replace any generators over the next ten years.

Generators support our asset management objectives by effectively serving as backup power sources and enhance overall network reliability and quality of supply. Our objectives for generator assets are:

- Provide a reliable backup power source to support critical loads during planned or unplanned outages.
- Eliminate/avoid outages to sensitive customers and reinforce weak network while doing planned work.
- Stabilise voltage levels within acceptable limits to safeguard sensitive equipment and ensure consistent power quality for consumers.
- Improve the reliability of the distribution network by serving as a standby power source, reducing the frequency and duration of outages.
- Provide quick power restoration to areas affected by outages during faults.

7.18.2 Asset description

We have 14 diesel generators as shown in Table 7.18.1. They include:

- **400V truck-mounted mobile generators** – used to restore or maintain supply at a low voltage level during a fault or planned work.
- **400V building generators** – all have synchronisation equipment and can maintain the entire building load. A 110kVA unit is attached to the remote Transportable Data Centre (TDC) to ensure continuity of supply for this critical asset in contingency conditions. A 550kVA unit is attached to our main office building with another 550kVA unit is installed at Connetics' base in the Waterloo Business Park.
- **400V emergency standby generators** – can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Two 550kVA units are at Papanui Zone Substation. The 11kVA, 30kVA and 66kVA units which have no synchronising gear are also at Papanui.

We have six diesel tanks and a mobile trailer tank. The purpose of the tanks is to:

- Provide an emergency reserve supply for the operator vehicle fleet and building generator should the Christchurch supply lines become disrupted.
- Fuel mobile generators for high power work.
- Fuel the generator at our office building on Wairakei Rd in an emergency for an extended period.
- Fuel mobile generators (trailer tank).

Table 7.18.1 Generator types

Voltage	Type	kVA				Total	Avg age
		8 - 30	66 - 110	330 - 440	550		
400V	Mobile		2	2	1	5	12
	Building generators		1		2	3	10
	Emergency standby	2		1	3	6	14
Total						**14**	

7.18.3 Asset health

There have been no major mechanical issues with the generators.

Table 7.18.2 Generator conditions by type

Voltage	Type	Condition
400V	**Mobile**	Good condition
	Building generators	Good condition
	Emergency standby	Good condition

7.18.3.1 Issues and controls

Our generators are rotating machines that are subject to vibration, heat and dust while running and in transit. As a result, our generators require regular maintenance and tuning to ensure that they stay in an optimal state. We find and replace most issues during our routine maintenance.

7.18.4 Maintenance plan

We employ a number of different maintenance approaches for different generator groups. The different types of generators and ages require different schedules to best suit each machine. The schedules are shown in Table 7.18.3.

Table 7.18.3 Generator maintenance plan

Generator type	Scheduled maintenance
Mobile generators (400V, 110-440kVA)	Oil changed every 250 hours (note the interval is smaller for the older engines in this group of generators) Diesel and batteries tested yearly Complete functional test once a year Battery charger and block heater kept plugged in
Emergency generators (400V, 400V, 550kVA)	Battery charger and block heater kept on Oil tested yearly and changed every 3 years or every 500 hours whichever comes first Tank fuel air filters changed every 3 years Diesel and batteries tested yearly Test run monthly Run on a load bank for 30 minutes once a year at full load

7.18.5 Replacement plan

We regularly maintain our generators and when one approaches end of life, a condition-based assessment will be conducted to see when the replacement is most economical. Our 440kVA generator is nearing the end of its operational lifespan and approaching the 10,000-hour mark. We will evaluate whether it makes better economic sense to undergo significant maintenance or replace it with a new unit. Budgetary provisions have been made for this upcoming renewal in the coming years, including the replacement of two controllers and Automatic Voltage Regulator (AVR) units annually.

7.18.5.1 Disposal

Generators are disposed of by auction when they become surplus to our requirements or they become uneconomic to continue to operate.

Our network procedures detail the disposal requirements for substances such as fuels that have the potential to spill from generators or any other form of holding or transport tank.

These procedures also mandate the prompt reporting of any uncontained spillage and disposal of hazardous substances, which allows us to document the details of spillage and disposal quantities.

We have replaced most of our monitoring assets in recent years and are confident in their performance.

7.19 Monitoring and power quality

7.19.1 Summary

Orion's monitoring assets are high voltage (11kV), GXP metering equipment and power quality meters. We have replaced most of our monitoring assets in recent years.

Monitoring assets support our asset management objectives by determining performance of our distribution network and how it changes over time. Our objectives for monitoring assets are:

- Ensure precise measurement of electricity usage for accurate billing.
- Enable remote monitoring and collect real-time data to make informed decisions and optimise network assets.
- Understand the level of service quality provided throughout the distribution network.
- Identify system improvements that can mitigate power quality problems.
- Enhance customer service by diagnosing power quality related issues.
- Ensure that metering systems comply with industry regulations and standards.

7.19.2 Asset description

Our monitoring assets cover four areas in our network:

- **High voltage (11kV) customer metering** – we own metering Current Transformers (CTs) and Voltage Transformers (VTs) along with associated test blocks and wiring at approximately 45 customer sites. Retailers connect their meters to our test blocks and all Orion metering transformers are certified as required by the Electricity Governance Rules.
- **Transpower (GXP) metering** – we own metering equipment at Transpower Grid Exit Points(GXP). The data from our meters serves as input into our SCADA system for load management and as check meters should Transpower's meters fail.
- **Power quality monitoring** – we have installed approximately 33 permanent, standards compliant, power quality measurement instruments across a cross-section of distribution network sites with varying load types. Data collected is analysed to assess long-term trends in performance and to assist in the development of standards and regulations and future power quality improvement projects.
- **LV monitoring** – we have installed more than 600 LV monitors across our network to gain better visibility of our LV network. LV monitoring provides us with real time usage at street level and enables us to respond to changes in network usage and plan our future strategies for the development of the LV system.

7.19.3 Asset health

7.19.3.1 Condition

Metering CTs are generally robust long-life assets with few failure modes. They are regularly tested and calibrated in accordance with Energy Market rules and replaced if non-compliant. Our monitoring equipment is relatively new and in early life.

7.19.3.2 Performance

We check our non-revenue metering data against Transpower's data if there is a significant difference, meter tests may be required to understand where the discrepancy has occurred.

Our power quality management has historically been largely reactive as we have built our methodologies around responding to customer power quality reports. However, we now also focus on projects that are proactive in nature which when completed will reduce the number of complaints we receive and improve our network performance.

We will continue to monitor the power quality to assess the impact of the increasing number of non-linear loads that are connected each year.

7.19.3.3 Issues and controls

Metering transformers are extremely reliable standard components of high voltage switchgear and are maintained and replaced as part of our standard switchgear maintenance and replacement procedures. We hold sufficient spares to cover failures of CTs, VTs and other metering equipment.

7.19.4 Maintenance plan

We regularly inspect the metering sites, carry out appropriate calibration checks and witness the calibration checks on Transpower's metering. Our meter test service providers are required to have registered test house facilities which comply with the Electricity Governance rules. They are required to have documented evidence of up-to-date testing methods and have competent staff to perform the work.

The maintenance plan is shown in Table 7.19.1. The capital expenditure will be used to conduct testing of HV meters every 10 years for certification as well as maintaining our statcoms on an annual basis.

We will continue to monitor the power quality to assess the impact of the increasing number of non-linear loads that are connected each year.

Table 7.19.1 Monitoring maintenance plan

Maintenance activity	Strategy	Frequency
CTs & VTs	The Electricity Marketing rules require that our CTs and VTs must be recalibrated	10 years
Power quality meters	Repaired / replaced when they fail	As required
LV monitoring	Repaired / replaced when they fail	As required

7.19.5 Replacement plan

Monitoring assets are considered non-critical, and typically, a reactive approach is employed to identify necessary replacement work. However, we have implemented implementing a capital expenditure program to proactively replace our power quality meters due to aging issues.

We maintain spares, and a limited budget is allocated for unforeseen replacements.

The replacement expenditure is based on replacing end of life meters and metering equipment over the next 10 years.

Orion has 96 vehicles to enable us to operate and maintain the electricity network, engage with the community and respond to network events.

7.20 Vehicles

7.20.1 Summary

Orion has 96 vehicles to enable us to operate and maintain the electricity network, engage with the community and respond to network events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver.

Orion's vehicle strategy is to electrify our fleet where the required vehicle is fit-for-purpose. Over the past eight years we have progressively migrated our vehicle fleet to electric, with a mix of full Battery-powered EVs and Plug-in Hybrid EVs. Demonstrating our commitment to electrification, in FY23 66% of our passenger fleet was electric-capable. Our target is towards achieving electrification in 100% of the passenger fleet by the end of this AMP period, March 2035. We continue to use diesel-powered heavy-duty vehicles for generator trucks and diesel utilities for our network operator's vehicles as these are the only fit-for-purpose vehicles available at this time for business-as-usual operations and when working under severe weather conditions and undertaking emergency repairs.

Orion owns rather than leases its vehicles and has a variety of brands of mid-range vehicles in our fleet. We are open to purchasing new brands in an increasingly diverse EV market.

Currently, hydrogen-powered vehicles are not an option for us, but we keep a watching brief as the hydrogen vehicle sector evolves, particularly for heavy duty vehicles.

Our target is towards achieving electrification in 100% of the passenger fleet by the end of this AMP period, March 2035.

7.20.2 Asset description

Around 66% of our passenger fleet has electric drive capability. The performance criteria vary for each vehicle class. All are operated within their manufacturer specified parameters. Our vehicles are relatively new and regularly maintained. As a result, they are in good condition.

For a summary of our vehicle quantities and type, see Table 7.20.1.

Table 7.20.1 Vehicle quantities and type

Description	Quantity	Lifecycle
Generator truck	4	20 years
Network operator utility	22	5 years or 200,000 km
Battery Electric Vehicle (BEV)	17	6 years
Plug-in Hybrid EV (PHEV)	29	6 years
Other	24	4 years on average (earlier for high km's)
Total	**96**	

7.20.3 Maintenance plan

All vehicles within their warranty period are serviced according to the manufacturers' recommended service schedule by the manufacturers' agent. For vehicles outside of their warranty the servicing requirements are also maintained in accordance with the manufacturers' specifications by a contracted service agent.

7.20.4 Replacement plan

Our fleet replacement plan aims to replace vehicles on a like-for-like basis, where applicable, when the vehicle reaches its designated age or distance covered. If the fundamental needs of the driver change, the change will be reflected in the type of vehicle purchased for replacement. Where possible we purchase vehicles that better fit our needs and where there is a demonstrable gain in safety, efficiency, reliability and value for money. In keeping with our strategic focus on sustainability and commitment to reducing our carbon footprint, where they are fit-for-purpose and cost-effective we will seek out electric vehicle options.

7.20.5 Vehicle acquisition plan

The aim is to have the right vehicle and driver in the right place at the right time. This is a critical aspect of operating our network in a safe, reliable and efficient manner. The key drivers in our vehicle acquisition plan are:

- fitness for purpose
- safety
- reliability
- sustainability and fuel economy
- value for money/lowest economic cost over the life of the vehicle (including disposal value)
- diversity within the fleet – spreading the risk

7.20.6 Disposal plan

Our vehicles are typically disposed of via auction. In this way we achieve a market value for the vehicle and also incur the minimum disposal cost in terms of time and money.

8

Developing our network

Photo: Chris Linton, Delivery Supervisor, Connetics, and his team replaced switchgear at Heathcote substation.

Contents

8.1 Introduction

In this section we set out how we are developing our network to respond to the growing needs of our region and the opportunities presented by the transition to low carbon energy. We are ensuring Orion is prepared for a future driven by changing demands on our infrastructure.

We describe the major investments we plan to make in our high voltage (HV) and low voltage (LV) networks over the next 10 years. These planned investments are categorised into programmes by the network areas they impact to enable customers to readily identify projects that will most affect them. For the programmes of maintenance and replacement work that ensures the efficient day-to-day operation of our network, see Section 7.

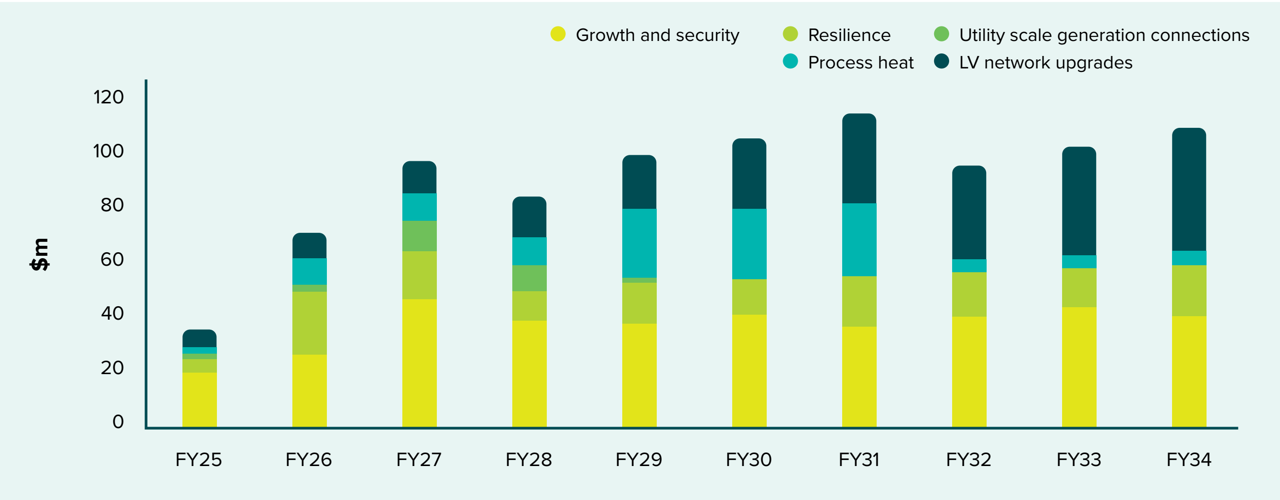
The demand for electricity is expected to increase significantly in the coming decades as the pace of decarbonisation accelerates, and the factors driving this change are set out in Section 2. This demand, combined with low carbon energy sources becoming increasingly distributed throughout our network, will require increased investment in traditional assets and new technology.
To assist our planning in an environment that is uncertain and evolving we have explored various possible scenarios.

We have selected the Central Scenario as the basis for planning our network development programme. See Section 6.4.

For the planned network development capital expenditure across our whole network over this 10-year AMP period, see Figure 8.1.1.

The development of Orion's network to meet future needs has significant implications for expenditure. We make every effort to keep our costs as low as possible in the interest of customer prices, including introducing a range of efficiencies and optimisations, many as a result of our focus on data and digitisation of our operations and unlocking the potential of our current asset base. We will also explore options to release value from customer owned devices to offset traditional network capital expenditure. Where feasible, these options will defer or prevent implementing a traditional network project solution by using cost-effective non-traditional flexibility service solutions our end-use customers or third-party aggregators provide. Where flexibility solutions are implemented, our operating expenditure will increase but greater savings in capital expenditure will be made, providing a net benefit for our customers.

Figure 8.1.1 Network development capital expenditure high-level breakdown (real)



In Section 8.3, we compare the current nominal network loading to our Security of Supply Standard and how we are addressing any gaps. For future network loading changes from organic load growth, decarbonisation and technology change at GXP and zone substation level, see Section 8.2.

Once the constraints have been defined, we investigate options to address them. For an outline of this process, see Section 6.4.3.

Our process heat conversion capital expenditure forecast is linked to our scenario work and is guided by our targeted customer engagement and EECA's Regional Energy Transition Accelerator report for this region. This work revealed that many customer process heat conversion demands have only minor to moderate complexity and will not meet the regulated reopener threshold for capital expenditure. As per our list of network development projects, the precise timing and solution is only firm for the first one to two years with forecast uncertainty increasing the further out in the AMP 10-year period. However, we continually monitor changes that may impact the speed of process heat conversions and maintain our close collaboration with these customers to refine this forecast.

The demand for large utility-scale generation connections on to our network is expected to be sustained throughout the 10-year AMP period, but we have only included expenditure for projects where we have a high-level of confidence in the scope and timing. It is also expected that these connections will be majority funded by the connecting party.

There are no customer load connections over 5MW in the first part of our expenditure forecast (FY25 – FY30).

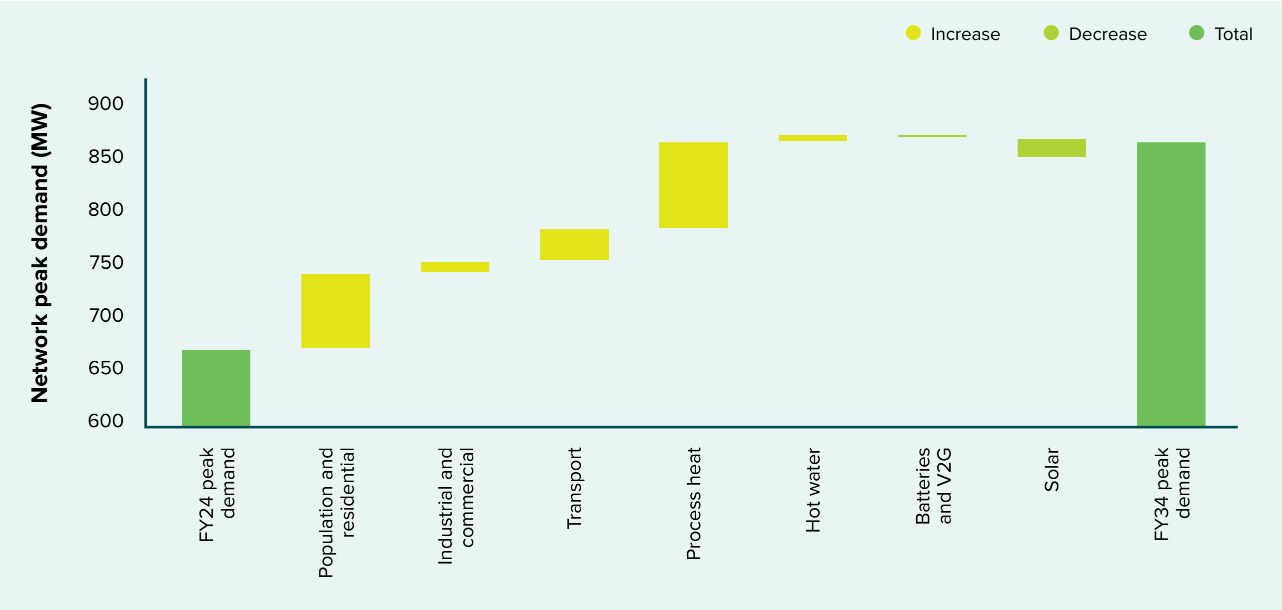
8.2 Network loading and forecast

Community and industry moves to decarbonise and strong population growth in our region are creating increasing demand for electricity across our network. Different parts of our network will be affected more than others based on a range of factors such as the customer make-up, zoning changes and population or business density. We have used plausible variations of these factors across Orion's network area to create our scenario modelling to inform our projections for zone substation peak loading.

In the future, as our scenario modelling matures and we integrate low voltage data, our load forecasting will be down to individual feeder, or street level. In future AMPs we will show more detailed load forecasts, including more nuanced upper and lower ranges. Currently, we are only able to show forecasts down to GXP and zone substation level.

For network development planning purposes, and for clarity within this section, we show the granular year-on-year forecast for the Central Scenario only, and test the range of change in five and 10 year scenario modelling output to indicate longer-term uncertainty. More detail of our approach including the inputs, assumptions and the scenario process can be found in Sections 2 and 6.

Figure 8.2.1 Central Scenario load growth by factor



Under the Central Scenario, we expect around 30% (~190MW) growth in total network peak demand between FY24 and FY34. We expect the peak to occur in winter with growth driven by process heat and residential building linked to population increase. Transport becomes a factor in later years but is likely to be seen sooner in some parts of the network where uptake of electric vehicles is higher. The major growth factors that contribute increases and, in some cases, decreases to the anticipated peak network demand in the next 10 years are shown in Figure 8.2.1.

In FY34 we expect to see more flattening of demand across the day and more distributed solar on the network. We also expect to see more daytime demand from EV charging, batteries, or other technology linked to solar generation. This could create more daytime peaks on peak days – see the FY34 peak day demand profile in Figure 8.2.2.

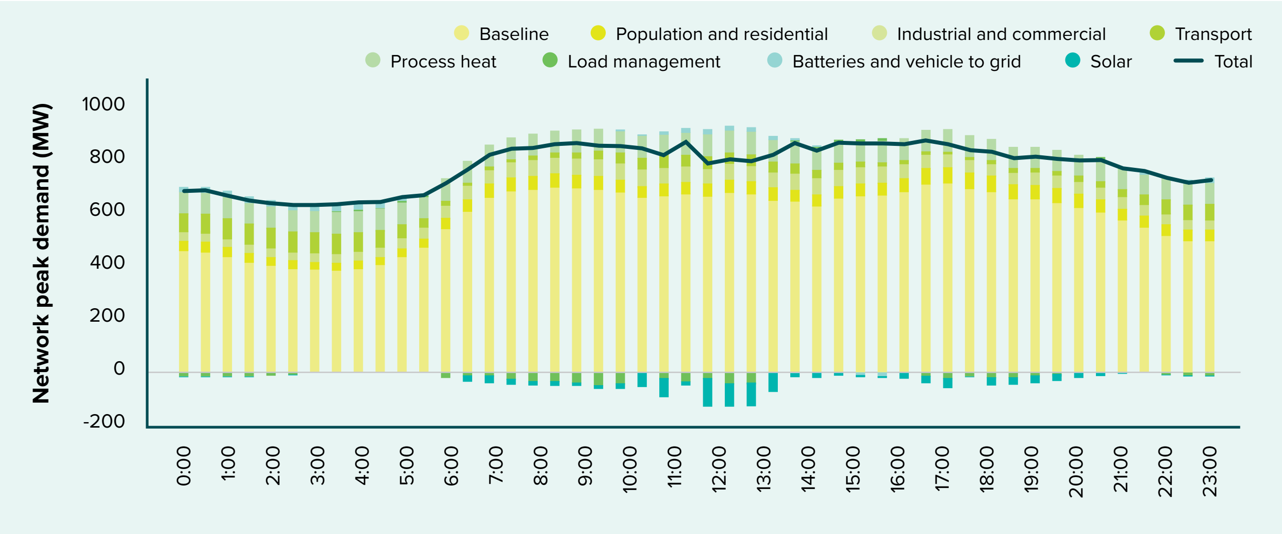
In our Central Scenario we assume evening peak EV charging demand can be shifted to overnight periods. Our approach to time of use pricing will incentivise this shift, but it is likely to need further incentive from retailers and information for EV owners to allow this to happen. More EVs charging during the evening peak period could add significantly to transport's contribution to peak demand.

Historically we managed our customers' controllable hot water cylinder load resource centrally to lessen the impact around peak load times. Our latest scenario modelling has identified that in the 10-year AMP period as the control of this resource transitions across to third parties, the effect of decentralised control during peak network demand periods will be less than 10% of our current hot water load control / flexibility, corresponding to around 6MW in FY34. As this potential loss is relatively minor compared to the broader uncertainties and our overall network development forecast, we have not allocated a capital expenditure line item for the loss of hot water control in this AMP.

For this 2024 AMP our forecast process heat load has been altered from 140MW, used in the 2023 AMP forecast, down to ~80MW. This reduction is based on the EECA/RETA report for our region and through our direct consultation with process heat customers.

8.2 Network loading and forecast continued

Figure 8.2.2 Peak day demand profile by factor – FY34 Central Scenario



To determine where future network security gaps will occur, each substation is assigned a Security Standard Class which outlines our restoration targets under different contingency scenarios. See Section 6 for further details. Firm capacity is determined by calculating the remaining capacity of each site should one item of plant fail (N-1).

These forecasts are our current best estimates and may change as our forecasting improves over time.

Our forecasts are also based on the current network configuration with no traditional or non-traditional solutions applied. Those relying on these forecasts are advised to contact Orion for current information if they are reliant on specific expected loads.

8.2.1 Transpower GXP load forecasts

Table 8.2.1 indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands over the next five years are also shown for our Central Scenario, along with the five and 10-year scenario modelling output range.

The impact of projects in this plan is not reflected in the load forecasts. The tabled loads are those expected if no development work is undertaken so the data here shows the need for the projects. Firm capacity is the capacity of each site should one item of plant fail. See Section 6.2.2 for a map of Transpower's system in Orion's network area.

Table 8.2.1 GXP substations – load forecasts (MVA)

GXP substation	Security Standard Class	Firm capacity	Peak season	Actual FY23	FY25	FY26	FY27	FY28	FY29	5 year range	10 year range
Bromley 66kV	A1	220	Winter	143	153	156	159	160	164	151 - 173	157 - 197
Islington 33kV	B1	107	Winter	76	76	78	79	81	82	82 - 82	90 - 92
Orion Islington 66kV	A1	480 [1]	Winter	441	440	449	459	468	477	435 - 492	446 - 560
Hororata 33kV	C1	23	Summer	20	19	20	21	22	22	21 - 22	23 - 24
Kimberley 66kV, Hororata 66 & 33kV	C1	70/59 [2]	Summer	42 [3]	47	48	49	50	51	51 - 51	54 - 55
Norwood 66kV	B1	220	Summer	N/A	30	30	30	31	45	29 - 45	29 - 73
Arthur's Pass	D1	3	Shoulder	0.3	0.3	0.3	0.3	0.3	0.3	0.3 - 0.3	0.3 - 0.3
Castle Hill	D1	3.75	Winter	0.8	0.7	0.7	0.7	0.7	0.7	0.6 - 0.7	0.6 - 0.7
Coleridge	D1	2.5	Shoulder	0.3	0.3	0.3	0.3	0.3	0.3	0.3 - 0.3	0.3 - 0.3

Notes:

1. 532 MVA total firm capacity. Assumes only 45% MainPower's of load is fed from Islington post Islington T6 contingency.
2. Assumes full generating capacity available from Coleridge. Can be limited to 59MW capacity when Coleridge is not generating or providing reactive support.
3. Recorded total circuit loading at Islington 0132 and 0292 circuit breakers.

Indicates load greater than firm capacity

8.2 Network loading and forecast continued

8.2.2 Zone substation load forecast

Tables 8.2.2 and 8.2.3 compare the firm capacity of each of our zone substations with present and forecast load.

Table 8.2.2 Region A zone substations – load forecasts (MVA)

Zone substation	Security Standard Class	Firm capacity	Peak season	Actual FY23	FY25	FY26	FY27	FY28	FY29	5 year range	10 year range
Addington 11kV #1	B2	30	Winter	19	20	20	21	21	21	20 - 22	21 - 25
Addington 11kV #2	B2	30	Winter	21	23	24	24	24	25	23 - 25	24 - 29
Armagh	A2	40	Winter	20	23	23	24	24	24	22 - 25	24 - 29
Barnett Park	B3	15*	Winter	10	10	10	10	10	10	9 - 10	9 - 12
Belfast	B3	15*	Winter	N/A	8	9	9	9	9	8 - 10	9 - 12
Bromley	B2	47	Winter	38	38	39	40	40	41	37 - 43	38 - 48
Dallington	B2	40	Winter	28	27	28	28	28	28	27 - 29	27 - 32
Fendalton	B2	40	Winter	36	35	36	36	36	37	34 - 41	35 - 45
Halswell	B2	23	Winter	19	21	22	23	24	25	23 - 25	26 - 33
Hawthornden	B2	40	Winter	32	34	34	34	34	35	32 - 36	32 - 38
Heathcote	B2	40	Winter	27	26	26	27	27	29	26 - 31	31 - 43
Hoon Hay	B2	40	Winter	30	31	32	32	33	33	31 - 36	32 - 41
Hornby	B2	20	Winter	14	16	16	17	17	17	16 - 18	16 - 19
Ilam	B3	11	Winter	8	8	8	8	8	8	8 - 9	8 - 9
Lancaster	A2	40	Winter	23	27	28	29	30	30	27 - 31	28 - 33
McFaddens	B2	40	Winter	36	35	35	36	36	37	34 - 38	35 - 41
Middleton	B2	40	Winter	28	30	32	35	37	38	31 - 40	31 - 42
Milton	B2	40	Winter	37	39	40	40	41	41	38 - 42	38 - 45
Moffett	B2	23	Winter	17	16	16	17	18	18	16 - 19	16 - 21
Oxford Tuam	A2	40	Winter	20	18	19	19	19	19	18 - 20	18 - 22
Papanui	B2	48	Winter	44	37	38	38	38	39	35 - 41	36 - 44
Prebbleton*	B3	15*	Winter	8	8	8	9	9	9	8 - 10	9 - 12
Rawhiti	B2	40	Winter	31	30	30	30	30	30	29 - 32	28 - 33
Shands	B2	20	Winter	16	14	14	14	14	15	14 - 15	14 - 16
Sockburn	B2	39	Winter	25	26	27	27	27	27	26 - 29	27 - 32
Waimakariri	B2	40	Winter	21	20	21	21	21	21	20 - 22	20 - 24

* Single transformer – security standard limits load to 15MW, 11kV ties from neighbouring sites provide backup capacity for all load.

Indicates load greater than firm capacity

8.2 Network loading and forecast continued

Table 8.2.3 Region B zone substations – load forecasts (MVA)

Zone substation	Security Standard Class	Firm capacity	Peak season	Actual FY23	FY24	FY25	FY26	FY27	FY28	5 year range	10 year range
Annat*	C4	8	Summer	4	4	4	4	4	4	4 - 5	4 - 5
Bankside*	C3	10	Summer	4	4	4	4	4	4	4 - 5	4 - 5
Brookside 66kV*	C3	10	Summer	8	8	8	8	8	8	8 - 9	8 - 9
Darfield*	B3	9	Summer	6	6	7	7	8	8	6 - 9	7 - 10
Diamond Harbour*	B3	8	Winter	3	3	3	3	3	3	3 - 3	3 - 3
Dunsandel	A2	23	Summer	17	16	17	17	17	31	23 - 45	14 - 59
Duvauchelle	B3	8	Winter	5	4	4	4	4	4	4 - 5	4 - 5
Greendale*	C3	10	Summer	6	6	6	6	7	7	6 - 7	6 - 8
Highfield*	C3	10	Summer	7	8	8	8	8	8	8 - 9	8 - 9
Hills Rd*	B3	10	Summer	7	7	7	7	7	7	7 - 7	7 - 8
Hororata*	C3	10	Summer	8	8	8	8	8	8	8 - 9	8 - 9
Killinchy*	C3	10	Summer	9	9	9	9	9	9	9 - 10	9 - 10
Kimberley	A3	23	Summer	14	14	15	15	15	15	14 - 38	14 - 39
Larcomb	B2	23	Winter	21	20	21	21	22	23	21 - 24	22 - 30
Lincoln	B3	11	Winter	11	11	11	11	12	12	11- 13	12 - 15
Little River*	C4	3	Winter	1	1	1	1	1	1	1 - 1	1 - 1
Motukarara	C4	8	Summer	3	3	3	3	3	3	3 - 5	3 - 5
Rolleston	B3	10	Winter	12	11	12	12	12	13	12 - 15	12 - 18
Springston 33kV	B2	60	Winter	38	36	36	37	38	39	35 - 41	37 - 50
Springston 11kV*	B3	13	Winter	9	8	8	8	8	9	8 - 12	8 - 12
Te Pirita*	C3	10	Summer	8	9	9	9	9	9	8 - 10	9 - 10
Weedons	B2	23	Winter	15	16	17	18	19	20	17 - 20	18 - 23
Lincoln + Springston 11kV	B3	22	Winter	19	17	17	18	18	19	17 - 21	19 - 27

* Denotes single transformer or line

Indicates load greater than firm capacity

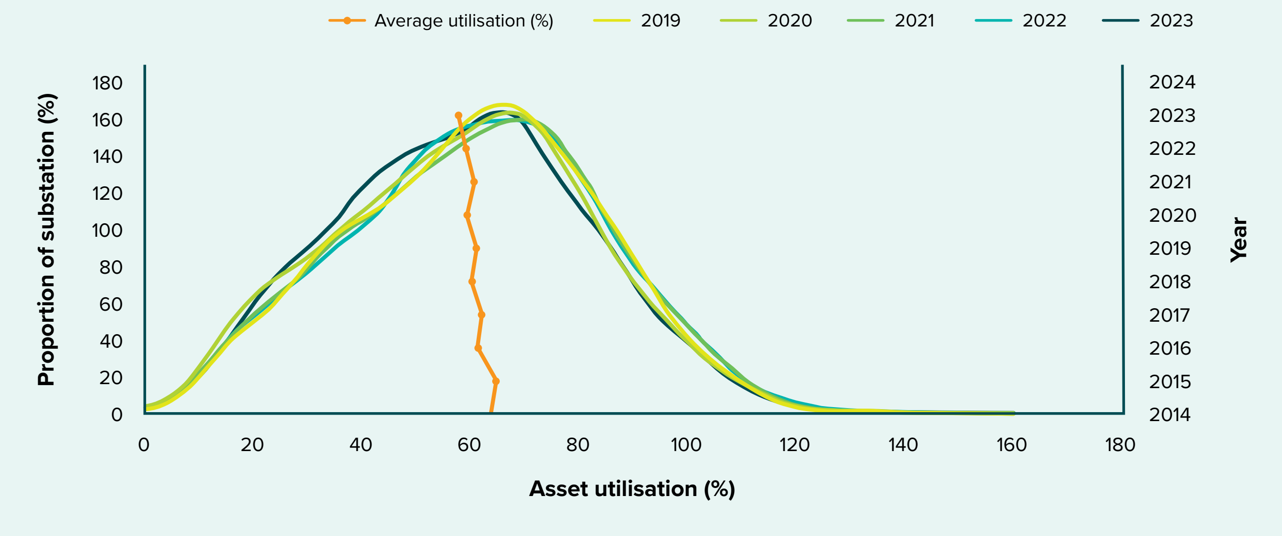
8.2.3 Distribution substation utilisation

As the energy system decarbonises there will be increased pressure on our 400V LV network. While we improve and develop our processes and data analysis capabilities to generate insights from LV smart meter data, we are using the loading of our distribution transformer fleet as a proxy for informing the loading of our LV network.

Figure 8.2.3 shows the distribution of utilisation factors for our 11/0.4kV distribution transformers. The graph has been determined by dividing the recorded maximum distribution transformer demands by the nominal transformer rating. We have discounted any transformer with less than ten customers from this analysis.

As the energy system decarbonises there will be increased pressure on our 400V LV network.

Figure 8.2.3 Distribution transformer utilisation graph



While the graph also shows that a proportion of distribution transformers are above 100% loaded at peak, the load factor for most distribution transformers is usually quite low. This is certainly true for transformers that supply mainly residential consumers. Transformers have a large thermal capacity and can tolerate cyclic loads higher than their continuous rating. For this reason, we allow peak loads on most distribution transformers to rise to 130% of the continuous rating before investigating possible replacement/upgrades.

8.3 Current network security gaps

To ensure our network remains reliable and resilient, we continually monitor the current loading and regularly perform power-flow contingency modelling to check compliance against our Security of Supply Standard, see Table 6.4.3.

Although gaps exist, some are deemed as extremely low-probability events and/or may be not economical to address because often restoration can be achieved remotely via a switchable solution from our Network Control Centre.

The Tables 8.3.1 and 8.3.2 show where gaps exist at our GXPs, subtranmission and zone substations together with possible options to resolve them, the relevent projects or programmes, and the proposed date where the gaps will be addressed.

Additional projects in the 10-year AMP period provide options to address future forecast gaps not stated here.

Table 8.3.1 Transpower GXP security gaps

Substation	Security Standard class gap	Gap detail	Proposed option	Proposed resolution date
Islington	A1 / B1	Full restoration unobtainable for an Islington 220/33kV dual transformer unplanned outage	Converting Shands Rd ZS from 33kV to 66kV introduces greater 11kV tie capability to remaining zone substations supplied by Islington 33kV.	FY30-32
Hororata	C1	Loss of all Hororata GXP load for a single unplanned 66kV bus outage (restorable)	Remove the majority of Orion load off Hororata GXP and supply from Norwood GXP. This requires the establishment an Orion 66kV busbar, construction of a new substation to replace Darfield ZS and the construction of the connecting circuits from Norwood GXP. On completion, all load for a dual Hororata transformer fault will be restorable. See the Hororata GXP capacity and security programme in Section 8.4.2.2 for details.	FY33
	C1	Only partial restoration achievable for a Hororata 66/33kV dual transformer failure		

Table 8.3.2 Subtransmission network security gaps

Substation	Security Standard class gap	Gap detail	Proposed option	Proposed resolution date
Dallington	B2	Loss of all load for a single unplanned 66kV cable outage. Restoration achievable in 5 minutes via remote switching	Complete the 66kV closed loop back to Bromley ZS. See Project 491.	FY28
Rawhiti	B2	Loss of all load for a single unplanned 66kV cable outage. Restoration achievable in 5 minutes via remote switching		
Waimakariri	B2	Loss of all load for a single unplanned 66kV cable fault. Restoration achievable in 5 minutes via remote switching	Complete a 66kV loop from Papanui via Belfast and Waimakariri. Project 1526.	FY36
Lancaster	B2	Loss of all load for a single unplanned 66kV cable fault. Restoration achievable in 5 minutes via remote switching	Create 66kV closed ring supply for Lancaster ZS. Achieved on completion of the Lancaster ZS to Milton ZS 66kV cable. See Project 589.	FY29
Milton	B2	If an N-2 transformer unplanned outage occurs during peak load times, full restoration to nominal supply area may not be achievable without overloading parts of the 11kV network.	Localised 11kV reinforcement and/or the use of flexibility.	TBA
Hororata	C2	Loss of all 33kV GXP load for a single unplanned 33kV bus outage (restorable through manual switching).	Installation of a bus coupler as part of 33kV switchgear lifecycle renewal outdoor to indoor conversion.	FY27
Norwood to Dunsandel 66kV circuit (Dunsandel, Killinchy and Brookside)	C2	Loss of all load for a single 66kV overhead outage on the Norwood ZS to Dunsandel ZS line. Restoration achievable via remote switching to Hororata GXP or Springston ZS.	Build the 66kV line between Norwood ZS and Brookside / Killinchy ZS. This will create, on completion, a closed loop between Norwood – Dunsandel – Killinchy – Brookside ZSs. See Project 941.	FY25

8.4 Optioneering and proposals

When we have exhausted our optimisation options, the optioneering process triggers the need for a project. This section lists our project proposals and opportunities for flexibility to address capacity and security constraints on our network. Our network development projects are driven by a variety of factors such as customer need, load growth, environmental considerations, and increasing overall network resilience.

We account for the time it takes to plan and undertake the proposed projects. This includes:

- the time required to procure and mobilise flexibility solutions
- the time required to procure zone substation land and/or negotiate circuit routes – typically one or two years
- the time required for detailed design – typically one year
- management of service provider resources by providing a consistent work flow
- procurement of major equipment may take up to 18-months, e.g. power transformers, 66kV cable etc

A major 66kV or 33kV network development project takes approximately four years to plan, design and build from a committed date. Smaller 11kV and LV projects take around 18 months. In a rapidly evolving environment, we are adaptable in how we implement our network development proposals, rather than rigidly adhering to a project schedule based on what could be an outdated forecast.

We show the alignment and linking of projects and programmes to our strategic focus areas and asset management objectives for each major programme grouping. See Section 2 for more details on our strategy and asset management objectives.

The key for project alignment with Orion Group Strategy and our asset management objectives is:

Primary objective | Secondary objective(s)

In the following pages we outline our network development projects and programmes of work planned for the next 10 years. Projects in the first two years of the plan are considered firm. Projects scheduled in the first five years of the plan have programme overviews and brief descriptions for each. Projects in the latter five years are outlined by project name and an indicative construction year only.

Our projects and programmes have been grouped into:

- Region A HV programmes of work, Section 8.4.1
- Region B HV programmes of work, Section 8.4.2
- Other HV projects, Section 8.4.3
- LV programmes of work, Section 8.4.4.

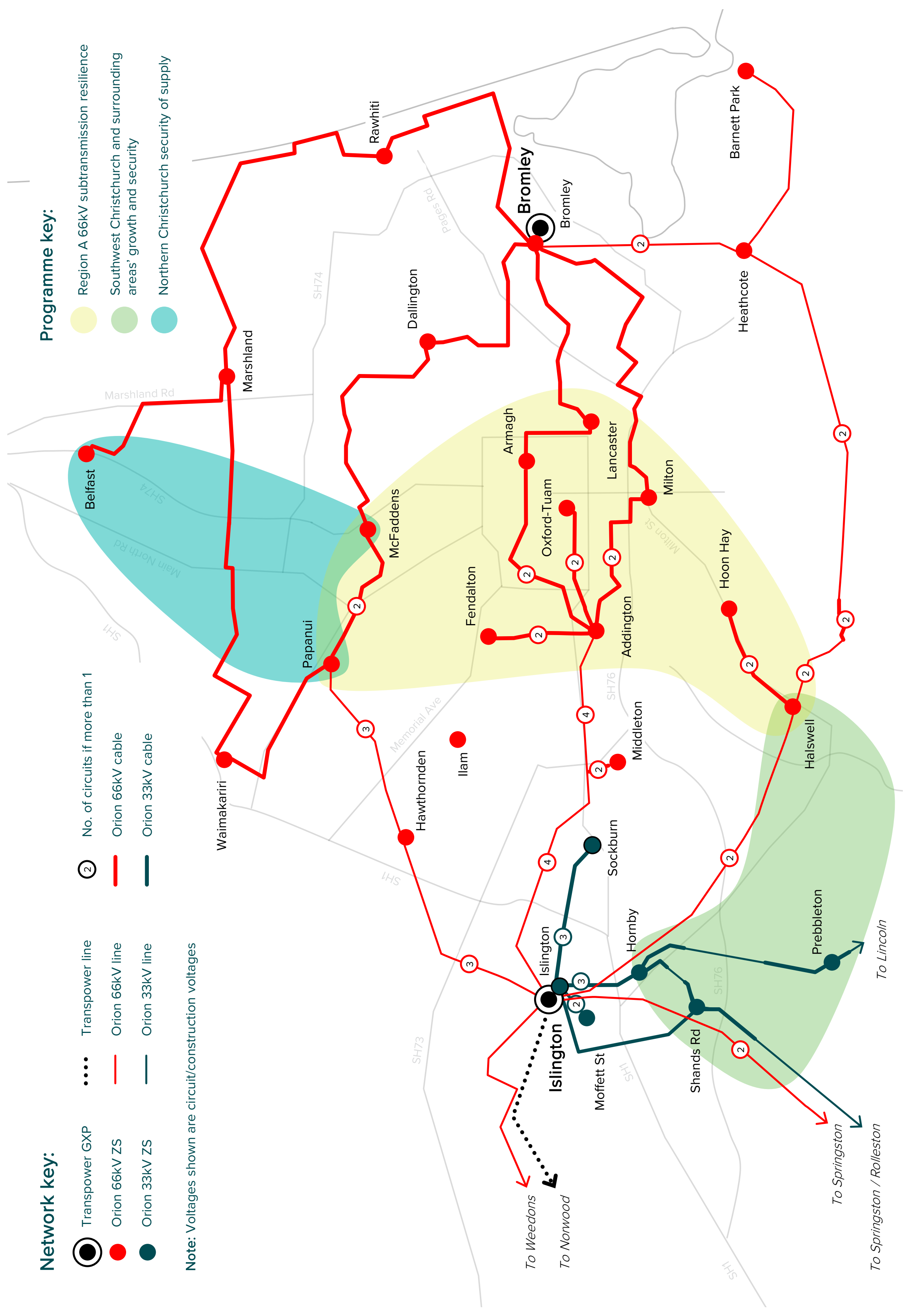
8.4.1 Region A HV programmes of work

Figure 9.4.1 provides an overview of the location of the major programmes of work across our Region A area. Further detail of the individual projects within each programme are in the relevant subsections. The programmes scheduled across the 10-year period are:

- Region A 66kV subtransmission resilience, Section 8.4.1.1
- Southwest Christchurch and surrounding areas' growth and security, Section 8.4.1.2
- Northern Christchurch security of supply, Section 8.4.1.3

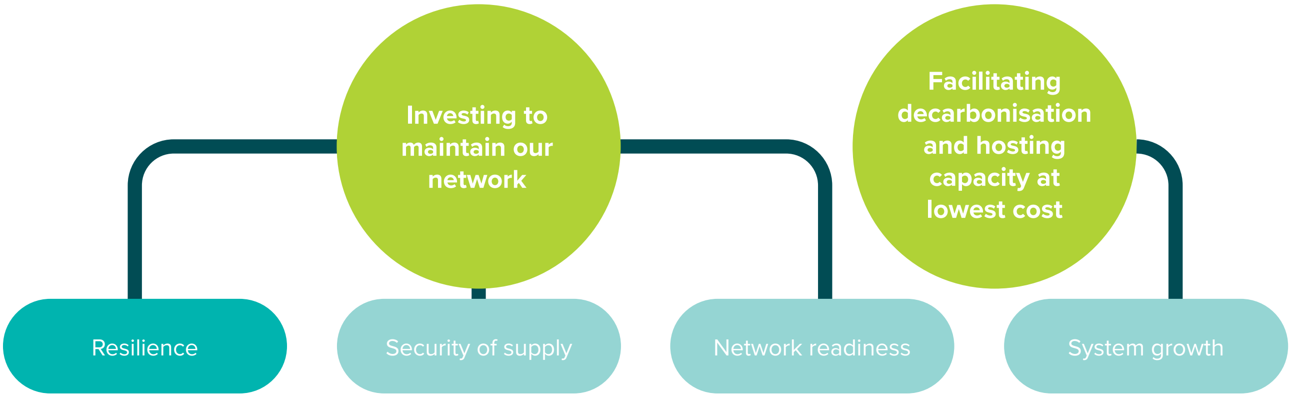
A major 66kV or 33kV network development project takes approximately four years to plan, design and build from a committed date.

Figure 8.4.1 Region A existing subtransmission network and proposed programme location overview



8.4.1.1 Region A 66kV subtransmission resilience programme

Investment drivers



To increase our urban 66kV subtransmission network's resilience against the impact of a major seismic event, in FY23 we began a programme to replace our remaining 40km of 66kV oil filled underground cables. As part of this programme, we are changing the architecture of our 66kV network to create supply diversity and strengthen the connections between the two major urban GXPs. Although resilience and obsolescence are the dominant drivers, this replacement programme also incorporates forecast network growth and other asset lifecycle replacement projects across our Region A 66kV network. See Section 7 for asset lifecycle information.

We considered non-traditional solutions, however due to the capacity required at a subtransmission level, these solutions are not suitable to supply base-level demand. Economically viable non-network solutions are unable to provide the required 66kV security. This is due to the lengthy fault restoration times that exceed the energy storage capability of existing Distributed Energy Resource (DER) systems during our winter peak load times.

An overview of the projects in this programme that fall within this 10-year plan are shown in Figure 8.4.2 with project descriptions in Table 8.4.1.

Figure 8.4.2 Proposed Region A 66kV subtransmission resilience programme projects

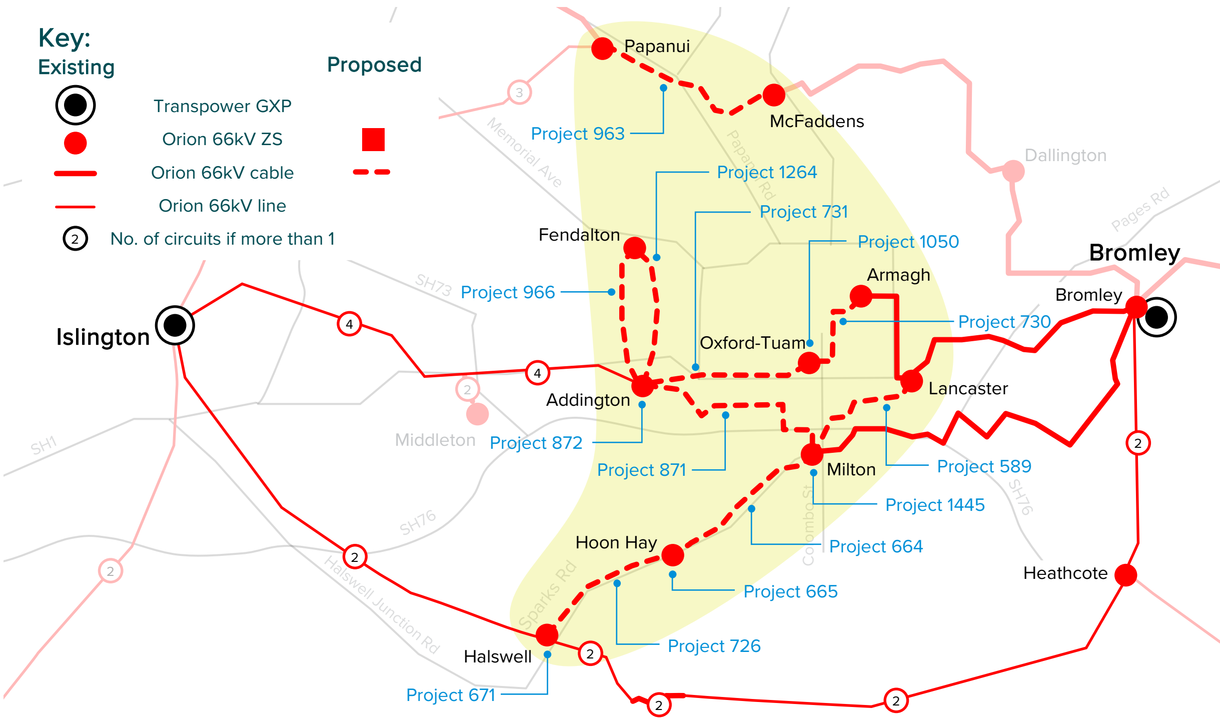


Table 8.4.1 Region A 66kV subtransmission resilience projects

No.	Project title		Year	Flexibility opportunity	Business case existing
664	**Milton ZS to Hoon Hay ZS 66kV cable**		**FY25-27**	**No**	**Yes**
	Issue definition	To facilitate the new Region A 66kV architecture as part of the 66kV oil filled cable renewal programme a cable connection between Milton ZS and Hoon Hay ZS is required.			
	Chosen option	This project is the purchase, installation and commissioning of a new 66kV cable between the newly constructed Milton ZS 66kV switchroom and the new Hoon Hay ZS 66kV switchroom – see Project 665.			
	Remarks	This project addresses the existing lack of route diversity supplying Hoon Hay and mitigates the emerging constraint on the Islington GXP – Halswell ZS tower line.			
665	**Hoon Hay ZS 66kV switchgear and building**		**FY25-27**	**No**	**Yes**
	Issue definition	Hoon Hay ZS is currently supplied via dual circuit transformer 66kV oil filled cable feeders from Halswell ZS. These cables are programmed for renewal with a new diverse route 66kV closed-ring supply from Bromley ZS.			
	Chosen option	This project is to construct, equip and commission a new 66kV switchroom at Hoon Hay ZS to enable connection of the new 66kV cable circuits from Halswell ZS (Project 726) and Milton ZS – see Project 664.			
	Remarks	The new building will fit within the existing Hoon Hay ZS site, but further land acquisition is needed to meet building set-back requirements.			
726	**Halswell ZS to Hoon Hay ZS 66kV cable**		**FY25-27**	**No**	**Yes**
	Issue definition	Hoon Hay ZS is currently supplied via spur dual circuit 66kV oil filled cables from Halswell ZS. These cables are a seismic vulnerability and do not provide a diverse route supply.			
	Chosen option	This project is the purchase, installation and commissioning of a new 66kV cable between the new Halswell ZS 66kV switchroom (Project 671) and the new Hoon Hay ZS 66kV switchroom – see Project 665.			
	Remarks	This project will supply Hoon Hay ZS with a 66kV supply with diverse supply routes while providing full N-1 security of supply.			
671	**Halswell ZS 66kV switchgear and building**		**FY25-27**	**No**	**Yes**
	Issue definition	Halswell ZS is a pivotal supply point for managing GXP loads on the current and future 66kV subtransmission network, but the limitations of the existing 66kV arrangement does not allow loads to be split between Islington and Bromley GXPs.			
	Chosen option	This project is the construction and commissioning of a new 66kV ring-bus and switchroom at Halswell ZS.			
	Remarks	This project has been timed to coincide with the lifecycle renewal of four 66kV CBs at Halswell ZS.			
1445	**Milton ZS transformer alteration**		**FY27-28**	**No**	**Yes**
	Issue definition	The Milton ZS transformers are direct fed from Addington ZS via dual 66kV oil filled cables. These cables are due for retirement and are seismically vulnerable.			
	Chosen option	Upon the completion of the Milton ZS to Hoon Hay ZS to Halswell ZS 66kV cables – Projects 664 and 726 – the Milton transformers are to be transferred over to the new Milton 66kV switching station.			

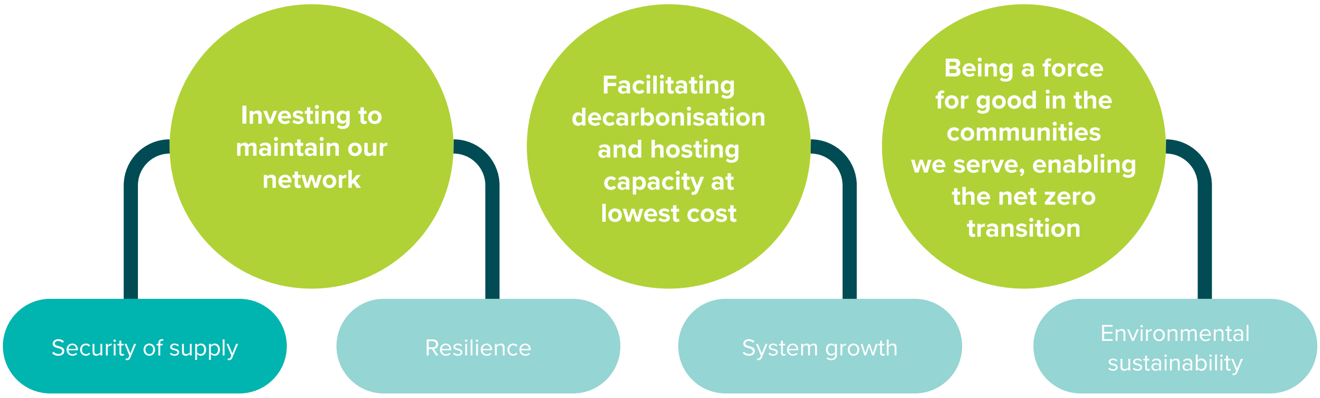
8.4 Optioneering and proposals continued

Table 8.4.1 Region A 66kV subtransmission resilience projects (continued)

No.	Project title		Year	Flexibility opportunity	Business case existing
589	**Lancaster ZS to Milton ZS 66kV cable**		**FY27-29**	**No**	**No**
	Issue definition	The post-earthquake architecture review highlighted that the high value Central City load requires additional subtransmission support. In particular, improved cover for the loss of Addington zone substation is needed. Lancaster ZS does not have full N-1 for single 66kV cable outages.			
	Proposed option	A new 66kV cable between Lancaster and Milton zone substations will provide extra security of supply for the CBD.			
	Remarks	This cable link was envisaged as part of our post-earthquake 2012 subtransmission architecture review.			
1050	**Oxford Tuam ZS 66kV switchgear and building**		**FY28-29**	**No**	**No**
	Issue definition	The proposed replacement Region A 66kV architecture has Oxford Tuam ZS on a closed-ring supply requiring a new 66kV switching station.			
	Proposed option	This project proposes to construct, install and commission a new 66kV indoor switching station adjacent to the existing Oxford Tuam ZS site.			
	Remarks	Projects 730 and 731 are the 66kV cable projects that connect this into the network.			
872	**Addington ZS 66kV bus coupler**		**FY28-29**	**No**	**No**
	Issue definition	Addington ZS 66kV currently operates as two separate 66kV supply points due to the lack of busbar protection or bus coupler.			
	Proposed option	This project proposes constructing and commissioning a new 66kV bay to create a bus coupler as well as fitting bus zone protection to the existing 66kV bus.			
	Remarks	This project will enable the 66kV bus at Addington to be operated closed upon completion of the new CBD 66kV ring and will improve power quality for all downstream Addington ZS customers.			
730	**Armagh ZS to Oxford Tuam ZS 66kV cable**		**FY28-30**	**No**	**No**
	Issue definition	Armagh ZS and Oxford Tuam ZS are each fed via two dual 66kV oil filled cables (four circuits in total) from Addington ZS. These are due for replacement to increase the resilience of the supply to the CBD. The new proposed overarching architecture has Armagh ZS being fed from Oxford-Tuam ZS.			
	Proposed option	Lay a new single 66kV circuit from Armagh ZS 66kV bus to the new Oxford-Tuam ZS 66kV bus – see Project 1050.			
731	**Addington ZS to Oxford-Tuam ZS 66kV cable**		**FY29-31**	**No**	**No**
	Issue definition	Oxford-Tuam ZS is currently supplied via spur dual circuit 66kV oil filled cables from Addington ZS. These cables are a seismic vulnerability and are to be replaced.			
	Proposed option	Lay a new single 66kV cable circuit between Addington ZS and Oxford-Tuam ZS.			
871	**Addington ZS to Milton ZS 66kV cable**		**FY30-32**	**No**	**No**
	Issue definition	Milton ZS is fed by dual 66kV oil filled cables that are vulnerable to common-mode failure. Milton ZS also does not have an alternate supply point.			
	Proposed option	Lay a new single 66kV circuit from Addington ZS to the Milton ZS 66kV bus completing the Addington to Milton to Lancaster to Armagh back to Addington ZS 66kV closed-ring.			
966	**Addington ZS to Fendalton ZS T1 66kV cable**		**FY31-33**	**No**	**No**
1264	**Addington ZS to Fendalton ZS T2 66kV cable**		**FY32-34**	**No**	**No**
963	**Papanui ZS to McFaddens ZS 66kV cable**		**FY33-35**	**No**	**No**

8.4.1.2 Southwest Christchurch and surrounding areas' growth and security programme

Investment drivers



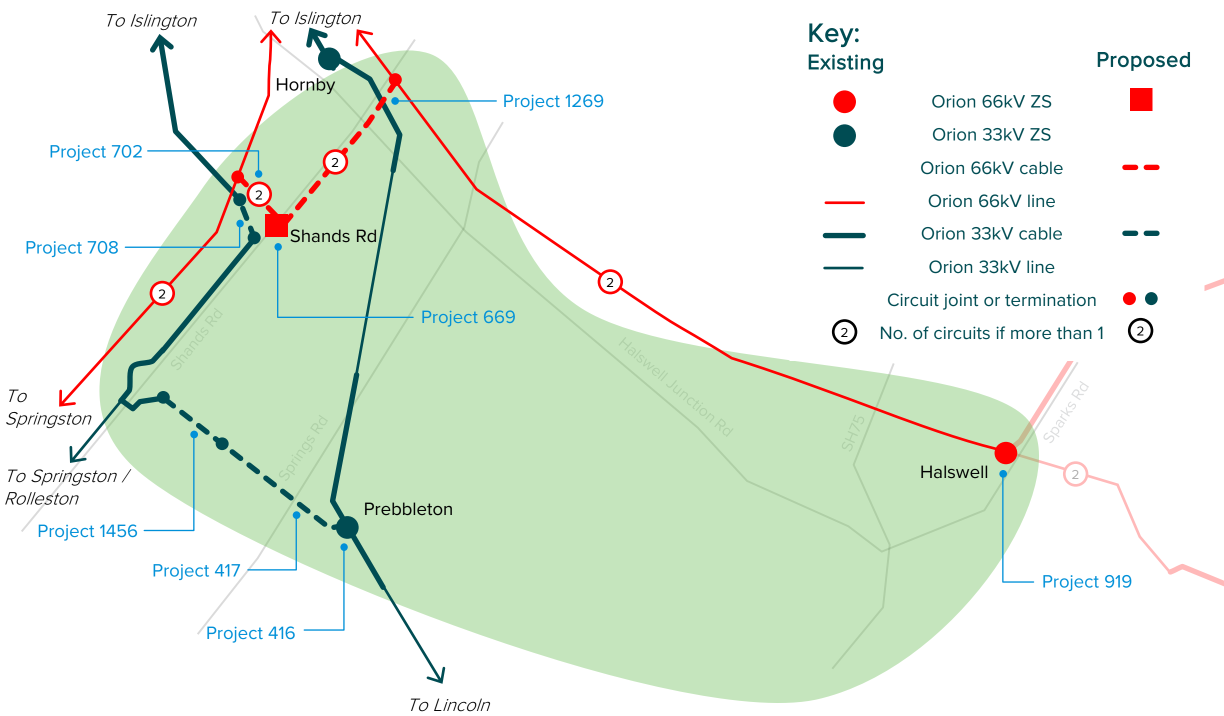
The southwest area of Christchurch and fringe townships are experiencing steady load growth due to the green-fields expansion of residential subdivisions in and around the Halswell suburb and Prebbleton township and the popularity of the Hornby industrial belt, on the fringe of Christchurch city.

The forecast load on the Halswell zone substation will exceed capacity and this programme of works will restore network security and provide headroom for the forecast increase in electric vehicle charging during peak load times. The significant subdivision expansion at Prebbleton and increased arterial route traffic is driving the need for major roading upgrades. Selwyn District Council driven safety improvements on major arterial routes requires parts of our 33kV network to be undergrounded. To ensure efficiency, we have catered for planned future works while roading work is underway.

A secondary driver is to address the resilience of the Islington GXP 33kV supply point. Shands Rd zone substation will be converted to 66kV, removing load from the 33kV system, strengthening the ability to fully restore load after a major double transformer fault 33kV outage.

Flexibility opportunities are possible with the proposed Halswell, Prebbleton and Shands Rd zone substation upgrades. We will he coordinate the timing of the Halswell zone substation network solution upgrade with the Region A 66kV subtransmission resilience programme to ensure the subtransmission architecture will support the additional load. See Section 8.4.1.1.

Figure 8.4.3 Proposed Southwest Christchurch and surrounding areas' growth and security projects – subtransmission



8.4 Optioneering and proposals continued

Table 8.4.2 Southwest Christchurch and surrounding areas' growth and security projects

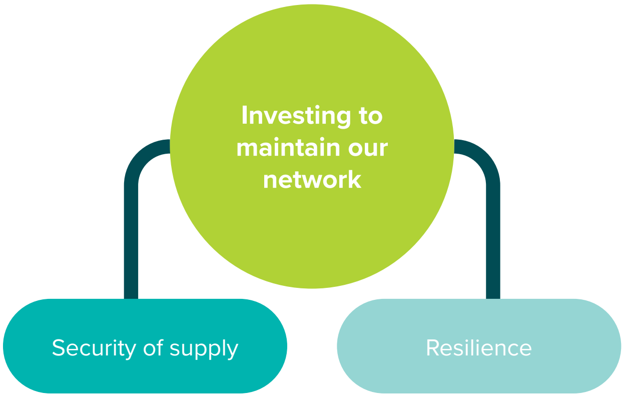
No.	Project title		Year	Flexibility opportunity	Business case existing
919	**Halswell ZS 3rd transformer and 11kV switchgear**		**FY26-27**	**Winter**	**No**
	Issue definition	High residential growth in the southwest of Christchurch has meant that the substation is forecast to exceed the N-1 limit.			
	Proposed option	Purchase, install and commission 3rd transformer and new 11kV switchgear for 3rd bus section. This project includes the creation of a third 11kV switchroom and 23MVA transformer pad construction.			
	Remarks/alternatives	The growth potential of the Halswell area means a network solution will be required to ensure the supply is resilience and secure, but we are investigating the use of flexibility to defer the timing of this project. Other options were assessed, including replacing the existing 23MVA transformers with 40MVA units, but this was much more expensive and would require the existing 11kV switchboards and transformer pads to be upgraded.			
1406	**Halswell south 11kV reinforcement**		**FY27**	**Winter**	**No**
	Issue definition	The 11kV network around Quaifes Rd, Sabys Rd and Glovers is becoming constrained due to subdivision growth.			
	Proposed option	Lay a new large capacity 11kV feeder out of Halswell ZS to reinforce the network to ensure network security can be maintained.			
	Remarks/alternatives	Part of the new feeders will be laid as part of a new subdivision development. There is an opportunity for flexibility to defer the need.			
1524	**Halswell west 11kV reinforcement**		**FY28**	**Winter**	**No**
	Issue definition	The majority of the load growth at Halswell has been to the south and west of the Halswell ZS. The 11kV distribution network is now stretched and now supplying load far beyond the original design capacity.			
	Possible option	Create two new 11kV feeders to split up the existing loaded ones.			
1456	**Hamptons Rd road widening reticulation**		**FY26-27**	**No**	**No**
	Issue definition	Prebbleton zone substation has an N security subtransmission supply so any 33kV circuit faults cause a complete loss of load and requiring restoration via 11kV switching.			
	Proposed option	The medium-term plan is to create a second 33kV feed into the Prebbleton zone substation.			
	Remarks/alternatives	In FY24 a new roundabout was installed at the Shands and Hamptons Rd intersection so the first part of the 33kV tee-off was installed. Selwyn District Council is widening Hamptons Rd from the road from the new roundabout so this proposal is in coordination with the road alterations to extend the cable further towards Prebbleton ZS.			
417	**Shands 33kV tee to Prebbleton ZS 33kV cable**		**FY27**	**No**	**No**
	Issue definition	Project 1456 does not fully complete the 33kV network extension to establish the new subtransmission feeder to Prebbleton ZS.			
	Proposed option	This proposal extends the 33kV cable laid in Project 1456 into Prebbleton ZS.			
416	**Prebbleton ZS 33kV switchgear and transformer**		**FY27-28**	**Winter**	**No**
	Issue definition	Projects 1456 and 417 extend the 33kV to provide a second alternate supply, but there is currently no way to connect it into the Prebbleton ZS 33kV bus.			
	Proposed option	Install additional 33kV switchgear to terminate the second subtransmission circuit.			
	Remarks/alternatives	This project will also explore installing an additional transformer at Prebbleton to increase the areas 11kV capacity as an alternative to transferring Shands Rd ZS over to 66kV – see Projects 708, 702 and 1269. The 33kV switchgear space, transformer pad and 11kV switchgear are already present at Prebbleton ZS.			

Table 8.4.2 Southwest Christchurch and surrounding areas' growth and security projects (continued)

No.	Project title		Year	Flexibility opportunity	Business case existing
669	**Shands Rd ZS site redevelopment**		**FY27-29**	**No**	**No**
	Issue definition	The 33kV and 11kV switchgear is due for replacement at Shands Rd ZS. The existing 33kV outdoor structure has inadequate space for the installation of our standard equipment. Also, the 11kV switchgear housed in pre-cast modular buildings is due for replacement, and is space constrained with no ability to expand the switchboard size.			
	Proposed option	As part of the surrounding industrial subdivision, we have secured an adjacent lot to Shands Rd ZS. This project proposes constructing new switchrooms to coincide with the lifecycle replacement of the 33 and 11kV switchgear. The 33kV switchroom will be constructed using 66kV rated equipment to prepare the site for conversion from 33kV to 66kV – see Project 708.			
	Remarks/alternatives	Equipping the existing modular buildings with new switchgear is not ideal due to the quantity of modifications required and physical constraints.			
708	**Shands Rd ZS 33kV to 66kV conversion**		**FY30-32**	**Summer and Winter**	**No**
	Issue definition	A combination of large industrial power users and process heat electrification could push Shands Rd ZS, and current 33kV subtransmission, beyond the firm capacity. Under an Islington 33kV HILP N-2 event we have identified that there is insufficient distribution capacity to carry the 33kV load, see Table 8.3.1 Transpower GXP security gaps.			
	Proposed option	Convert Shands Rd ZS from 33kV to 66kV by cutting into the Islington GXP to Springston ZS 66kV lines. This opens up more potential capacity and mitigates the HILP situation.			
	Remarks/alternatives	The Islington GXP to Springston ZS 66kV lines are limited in the ability to provide full capacity to Shands Rd ZS so options will be investigated as part of this conversion project. Options include utilising the spare capacity of the Islington GXP to Halswell ZS lines or reconductoring the line from Islington GXP with higher capacity aluminium conductor composite core (ACCC). The need date is highly dependant on step-changes in demand where the exact timing is unknown, therefore flexibility could provide opportunities to defer or eliminate the need to upgrade.			
702	**Shands Rd ZS 66kV termination poles**		**FY31-32**	**Summer and Winter**	**No**
	Issue definition	To establish Shands Rd ZS as a 66kV substation a connection to the 66kV network is required.			
1269	**Shands Rd ZS to Islington / Halswell ZS tower line 66kV cables**		**FY32-34**	**Summer and Winter**	**No**
	Issue definition	The Islington GXP to Shands Rd ZS line is loaded beyind N-1.			

8.4.1.3 Northern Christchurch security of supply programme

Investment drivers



Presently Orion's Belfast, Dallington, Rawhiti and Waimakariri zone substations are normally fed via single spur cable or open-ring 66kV supplies. These sites do not currently meet our Security of Supply criteria as they are vulnerable to complete outages for single 66kV subtransmission cable faults. This programme alters the current Marshland to Waimakariri zone substation 66kV connection to create two closed-ring 66kV supply rings back to the Bromley and Papanui substations.

We considered non-traditional solutions, however due to the capacity required at a subtransmission level these solutions are not suitable to supply base level demand. Economically viable non-network solutions are unable to provide the required 66kV security due to the lengthy fault restoration times that exceed the energy storage capability of existing known Distributed Energy Resource (DER) systems during our winter peak load times.

The additional transformer at Belfast zone substation will be a hot-spare to primarily provide resilience for Orion's growing fleet of 40MVA 66/11kV transformers as well as being available to provide N-1 to the Belfast substation.

Figure 8.4.4 Proposed Northern Christchurch security of supply projects

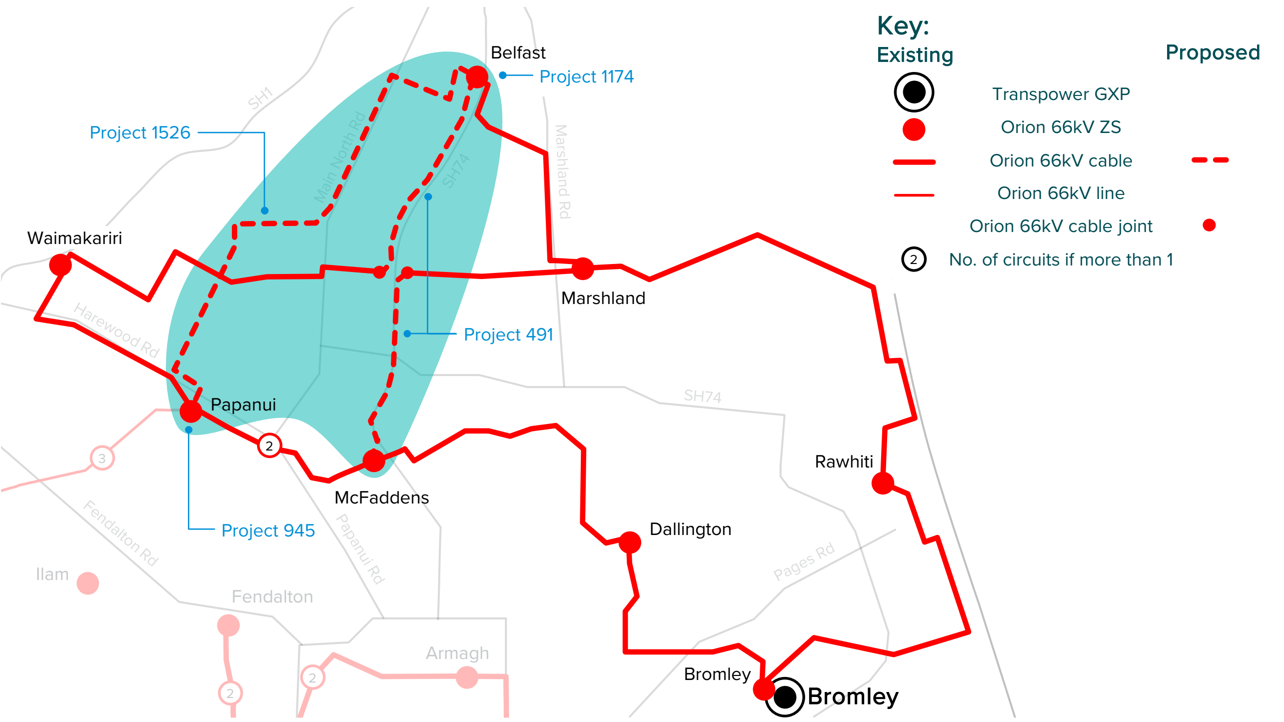


Table 8.4.3 Northern Christchurch security projects

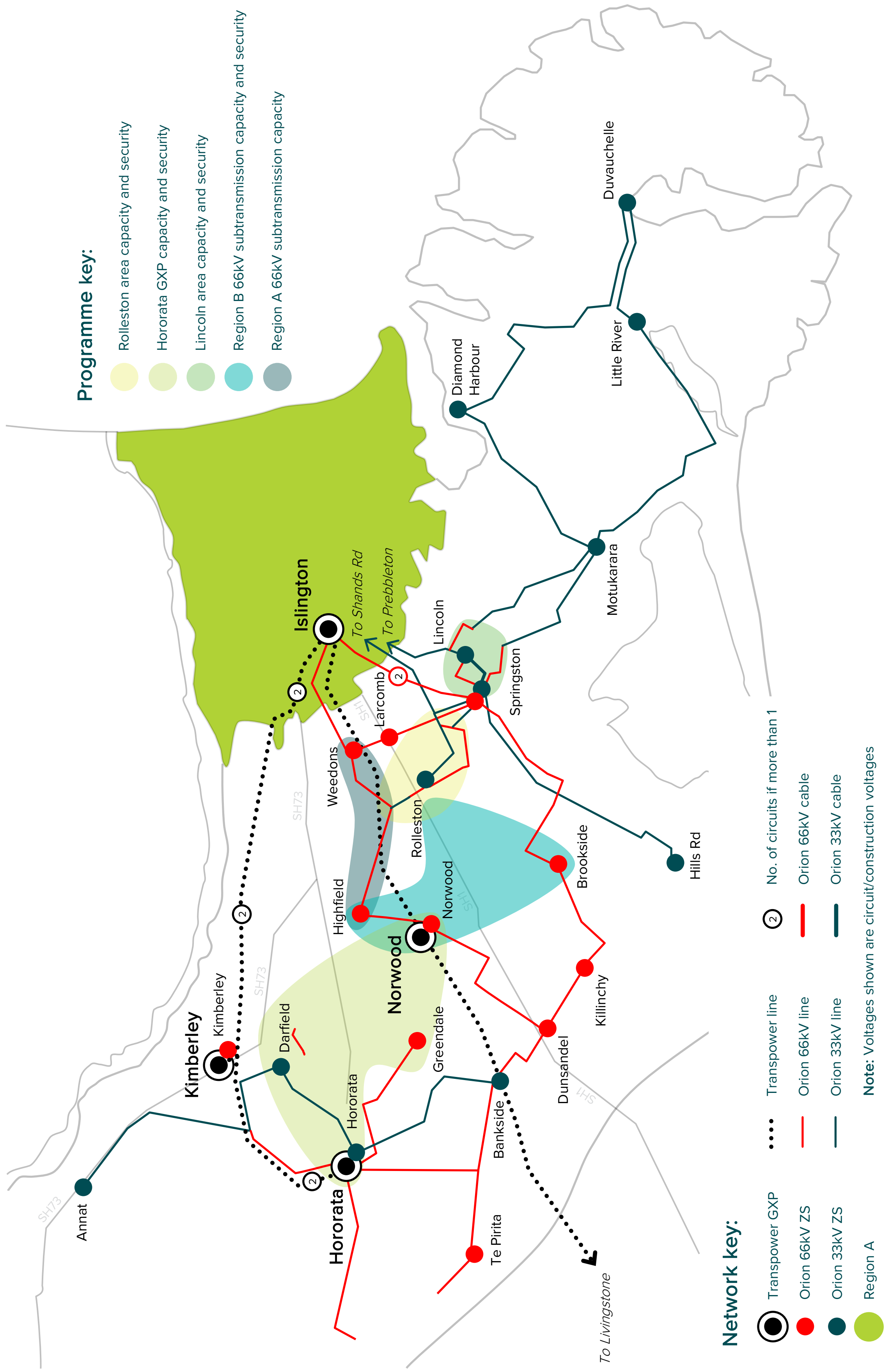
No.	Project title		Year	Flexibility opportunity	Business case existing
491	**Belfast ZS to McFaddens ZS 66kV cable links**		**FY26-28**	**No**	**No**
	Issue definition	Dallington ZS and Rawhiti ZS do not have an uninterrupted N-1 supply at 66kV which is in breach of our Security of Supply Standard. Belfast ZS has no alternate 66kV supply, so relies on 11kV ties for single 66kV cable outages.			
	Proposed option	This project establishes 66kV cable links from Belfast ZS to Waimakariri ZS and from Marshland 66kV switching station to McFaddens ZS.			
	Remarks/alternatives	Dallington ZS, Rawhiti ZS and Waimakariri ZS will have full N-1 security, and Belfast ZS switchable N-1, at 66kV on completion of this cable link project.			
1174	**Belfast ZS 2nd transformer / network spare**		**FY27-28**	**No**	**No**
	Issue definition	There is currently no network spare for the 40MVA 66/11kV power transformers and Belfast ZS does not have N-1 for transformer contingencies.			
	Proposed option	Purchase and install second 40MVA 66/11kV power transformer for Belfast ZS to act as the network hot spare or provide a firm 11kV supply.			
	Remarks/alternatives	This option provides both uninterrupted N-1 security of supply for the transformation at Belfast as well as providing a network spare transformer should one of the 40MVA transformers elsewhere in the network fault. All other options only provide one of these benefits.			
1526	**Belfast ZS to Papanui ZS 66kV cable**		**FY34-36**	**No**	**No**
	Issue definition	Belfast ZS and Waimakariri ZS have only switchable N-1.			
945	**Papanui ZS 66kV bay and additional bus coupler**		**FY34-35**	**No**	**No**
	Issue definition	The Papanui ZS 66kV two bus sections are supplied via three tower circuits from Islington GXP.			

8.4.2 Region B HV programmes of work

Figure 8.4.5 provides an overview of the location of the major programmes of work across our Region B area. Further detail of the individual projects within each programme are in each subsection. The programmes scheduled across the 10-year period are:

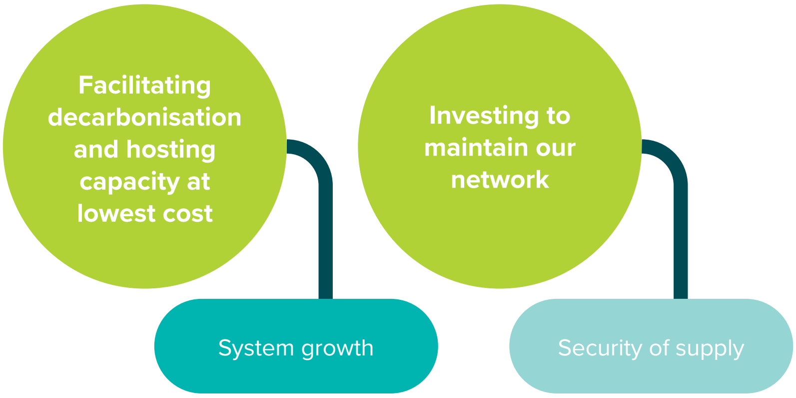
- Rolleston area capacity and security, Section 8.4.2.1
- Hororata GXP capacity and security, Section 8.4.2.2
- Lincoln area capacity and security, Section 8.4.2.3
- Region B 66kV subtransmission capacity and security, Section 8.4.2.4
- Region A 66kV subtransmission capacity, Section 8.4.2.5

Figure 8.4.5 Region B existing subtransmission network and proposed programme location overview



8.4.2.1 Rolleston area capacity and security programme

Investment drivers



The Rolleston area has experienced rapid load growth due to the township residential and industrial subdivision developments. This growth has pushed the Rolleston ZS beyond its firm capacity and all practical 11kV load transfers to the supporting zone substations at Larcomb and Weedons have been exhausted.

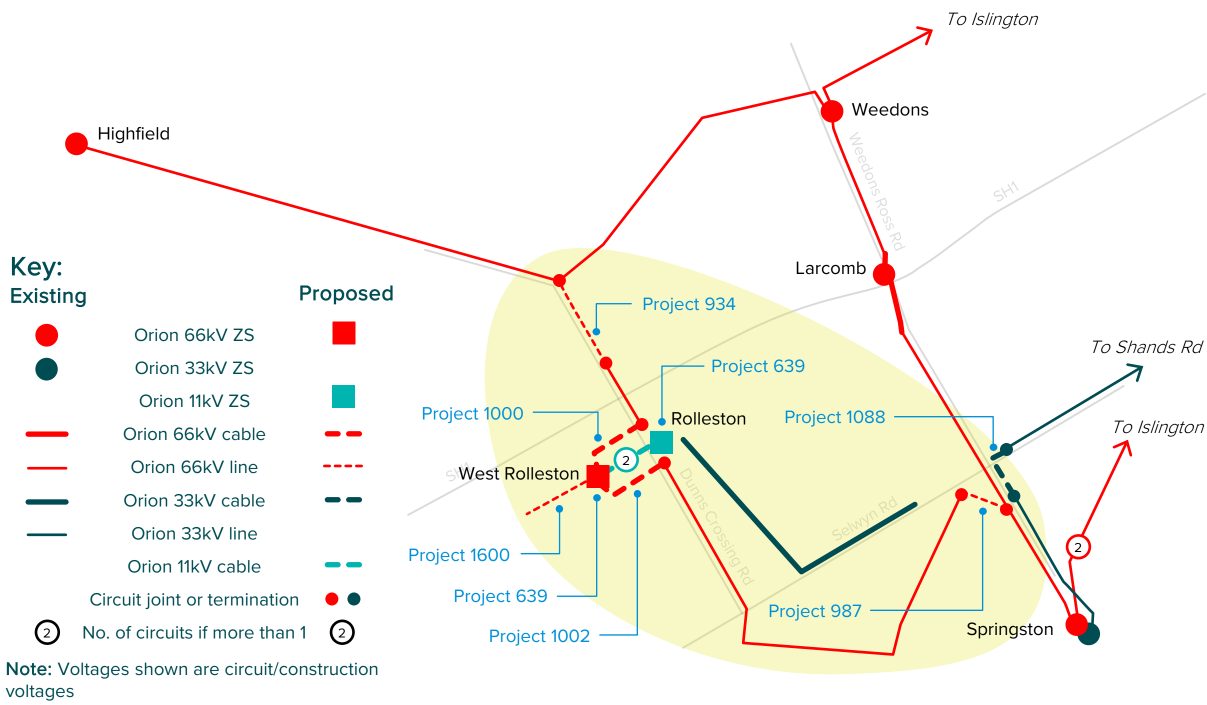
This programme of works addresses the local Rolleston township 11kV distribution capacity with the establishment of a new higher capacity substation to replace Rolleston ZS, named West Rolleston ZS. Works completed in FY24 have already strengthened the southern part of Rolleston back to Springston ZS, but continued growth is forecast in the short to medium term. The 11kV distribution capacity into the Izone industrial area is also being addressed with the creation of an 11kV switching station that will be supplied by the new West Rolleston ZS.

Due to Rolleston's strong growth rate, where 10 years of growth has occurred in three years, we have accelerated the construction of West Rolleston ZS. and will build it in stages over three years to manage the delivery. This speed of growth and the size of the security breach make non-traditional solutions utilising DER impractical.

We do anticipate that future capacity reinforcement could utilise flexibility to form a solution partially or fully. Early signposting of these opportunities is signalled in Table 8.4.6.

The new West Rolleston ZS will be initially supplied from Islington GXP, but will be transferred over to the new Norwood GXP to relieve capacity at Islington, see Section 8.4.2.4.

Figure 8.4.6 Proposed Rolleston area capacity and security projects – subtransmission



8.4 Optioneering and proposals continued

Table 8.4.4 Rolleston area capacity and security projects

No.	Project title		Year	Flexibility opportunity	Business case existing
934	**Walkers Rd 66kV line conversion**		**FY24-25**	**No**	**Yes**
	Issue definition	The overhead 33kV conductor between Highfield ZS and Rolleston ZS has progressively been upgraded to 66kV construction in anticipation of operation at 66kV. However, there is a small section remaining down Walkers Rd that has yet to be upgraded.			
	Chosen option	This project converts the remaining 33kV line construction, down Walkers Rd, between Two Chain Rd and Kerrs/Wards Rd, to 66kV construction.			
	Remarks	This project coordinates with other projects to meet the requirement of creating a 66kV ring to the new West Rolleston ZS.			
1000	**West Rolleston ZS to Dunns Crossing Rd north 66kV cable**		**FY24-25**	**No**	**Yes**
	Issue definition	The area surrounding the proposed West Rolleston ZS is becoming urbanised with residential housing and a school in close proximity. The existing 66kV constructed line down Dunns Crossing Rd needs to be diverted down Burnham School Rd into West Rolleston ZS.			
	Chosen option	This project is a new 66kV cable circuit to connect the new West Rolleston ZS onto the O/H line running down Dunns Crossing Rd to provide one leg of the ring supply back to Islington GXP.			
	Remarks	An overhead line option was considered but is not suitable due to the proximity of the school and houses. To avoid large termination structures in the road corridor we have chosen to utilise space within the Rolleston ZS switchyard.			
639	**West Rolleston ZS – new 66/11kV substation**		**FY24-26**	**No**	**Yes**
	Issue definition	The rapid load growth in the Rolleston/Izone area has caused the 11kV firm capacity of Rolleston ZS and the 11kV ties from supporting substations to be exceeded.			
	Chosen option	A new 66/11kV 23MVA capacity West Rolleston ZS will be built to replace the 33/11kV 10MVA capacity at Rolleston ZS. Part of the 11kV switchboard will be located at Rolleston ZS and supplied via 11kV incomers from West Rolleston ZS. The new design has provisions for an additional transformer if the load grows beyond 23MVA, see Project 1453.			
1002	**West Rolleston ZS to Dunns Crossing Rd south 66kV cable**		**FY25-26**	**No**	**Yes**
	Issue definition	To meet appropriate security of supply requirements, a second 66kV circuit heading east out of West Rolleston ZS is required to connect to the 66kV overhead line heading south down Dunns Crossing Rd.			
	Chosen option	This project is the installation and commissioning of a new 66kV cable down Burnham School Rd from West Rolleston ZS to a termination structure within the Rolleston ZS switchyard to establish a full N-1 supply.			
	Remarks	This project as well as Project 987 will provide the second 66kV connection to West Rolleston ZS by teeing into the Larcomb to Springston ZS 66kV line.			
987	**Springston Rolleston Rd 66kV line**		**FY25-26**	**No**	**Yes**
	Issue definition	The new West Rolleston ZS requires an N-1 supply.			
	Chosen option	The majority of the existing overhead subtransmission from Springston to Rolleston ZS has been rebuilt to 66kV construction as part of a lifecycle replacement programme so this project converts the last required section from 33kV construction to 66kV as well as a larger capacity conductor.			
	Remarks	This is the most cost-effective solution to provide the N-1 connection to West Rolleston ZS. This project uses a tee connection into the Larcomb to Springston ZS 66kV line rather than requiring an additional 66kV bay at Springston ZS.			

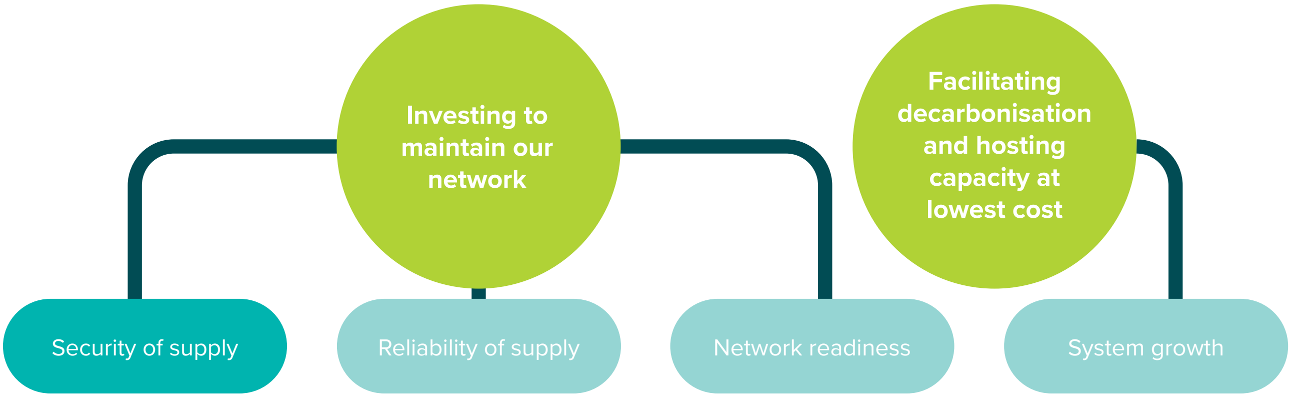
8.4 Optioneering and proposals continued

Table 8.4.4 Rolleston area capacity and security projects (continued)					
No.	**Project title**		**Year**	**Flexibility opportunity**	**Business case existing**
1088	**Weedons Rd 33kV cable**		**FY25-26**	**No**	**Yes**
	Issue definition	To maintain the 33kV support from Springston ZS to Shands ZS once the Selwyn Rd 33kV network is disestablished a new 33kV cable is required.			
	Chosen option	The cable will be laid from the corner of Weedons Rd and Lincoln Rolleston Rd to the corner of Weedons Rd and Selwyn Rd.			
1600	**Burnham School Rd – new 66kV line**		**FY25-26**	**No**	**Yes**
	Issue definition	To ensure the future connection from West Rolleston ZS to Norwood ZS is configured correctly limiting the alteration in the West Rolleston ZS switchyard the first section of line is required.			
	Chosen option	The chosen solution will be to construct the first section of overhead line out of West Rolleston ZS.			
1101	**West Rolleston 11kV reconfiguration**		**FY25-26**	**No**	**Yes**
	Issue definition	Once the subtransmission in Rolleston is all converted to 66kV to supply the new West Rolleston ZS (Project 639) the existing Rolleston ZS will lose its supply.			
	Chosen option	This project lays large capacity 11kV feeders from the West Rolleston ZS to create new 11kV incomers to Rolleston ZS to operate as a remote 11kV switchboard.			
637	**Two Chain Rd 11kV switching station**		**FY26-27**	**Summer and Winter**	**No**
	Issue definition	A large new industrial subdivision, adjacent to Izone, requires a new bulk supply point.			
	Proposed option	We propose that a new 11kV switching station be established at a future zone substation site. This new supply point will be fed from West Rolleston ZS via two 11.5MVA feeders.			
	Remarks	The future loading in this subdivision and Izone business park is unknown. The current headroom capacity is limited so any additional load will likely require reinforcement. Depending on the size of the increase, flexibility could be used to provide demand smoothing to manage the existing capacity. Larger increases will trigger the need to install the remote 11kV switchboard providing a firm 11.5MVA supply. Any increase in load above this will require a new zone substation.			
638	**Two Chain Rd 11kV – stage 2 cabling**		**FY27**	**Summer and Winter**	**No**
	Issue definition	The new switching station (Project 637) requires connection from West Rolleston ZS.			
	Chosen option	This project proposes extending the cables laid as part of the West Rolleston ZS 11kV works to the new switching station site.			
1453	**West Rolleston ZS 3rd transformer**		**FY32-33**	**Winter**	**No**
	Issue definition	It is anticipated that the load from the Rolleston township and new large point loads in the industrial park will push West Rolleston ZS beyond its firm capacity.			

8.4 Optioneering and proposals continued

8.4.2.2 Hororata GXP capacity and security programme

Investment drivers

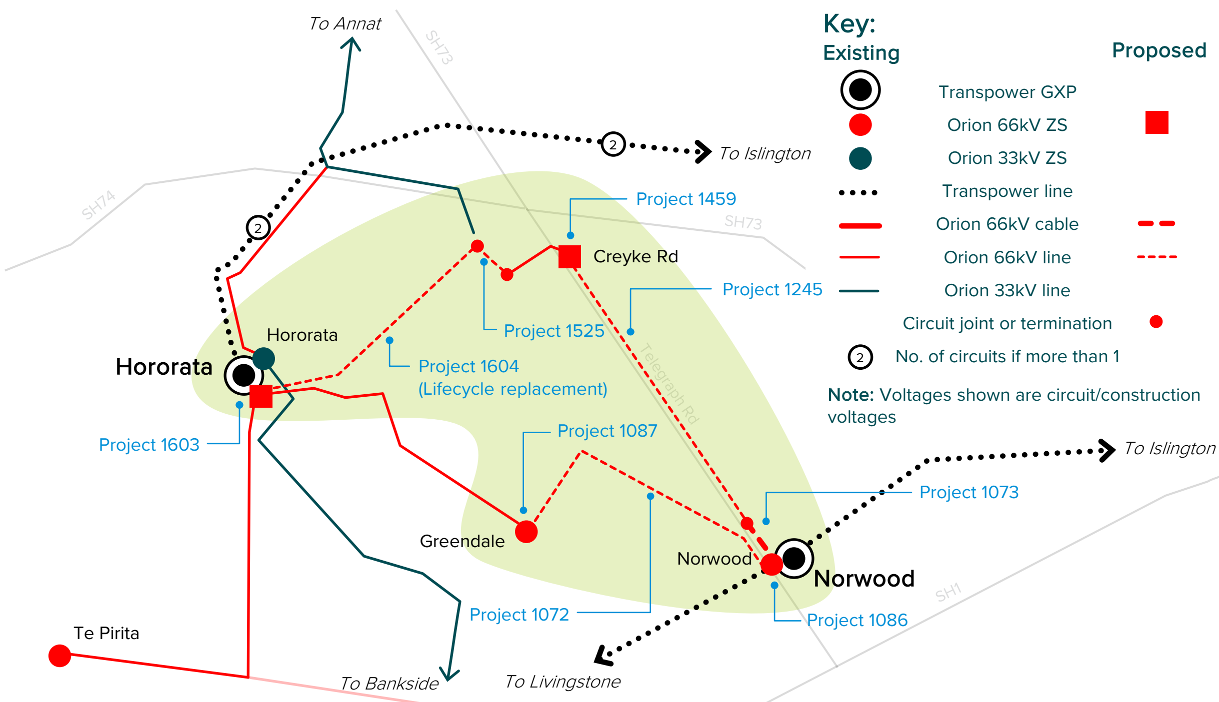


The Hororata 33kV GXP has reached the firm capacity due to increased loading from the Central Plains Water irrigation scheme. The Hororata GXP is also susceptible to large voltage excursions which cause sensitive customer loads to disconnect if a tripping occurs on either of the Islington to Kimberley to Hororata GXP lines. Any reduction of load will benefit the overall post-contingency voltage stability. This GXP also does not have a 66kV bus coupler so is exposed to single bus faults causing complete outages to the 66kV and 33kV Orion load and the connection through to Coleridge GXP.

The projects in Table 8.4.5 reduce the dependency on the Hororata GXP by creating new 66kV connections to Norwood GXP. These connections also unlock the ability to connect large scale renewable distributed energy resources located in this area that are currently constrained by the existing Hororata GXP network to a higher capacity national grid connection at Norwood GXP.

The township of Darfield is also growing and has been identified as a potential key electric vehicle charging location, as part of the national network, as well as the home to some medium sized process heat users. This growing load necessitates the need to expand the capacity and increase the reliability in this area. This programme constructs a new dual transformer 66/11kV substation to replace the existing single transformer 33/11kV one.

Figure 8.4.7 Proposed Hororata GXP capacity and security projects

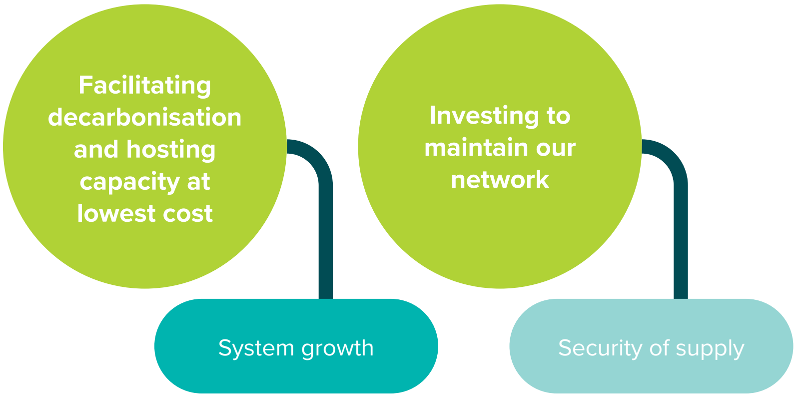


8.4 Optioneering and proposals continued

<table>
<tr><th colspan="6">Table 8.4.5 Hororata GXP capacity and security projects</th></tr>
<tr><th>No.</th><th colspan="2">Project title</th><th>Year</th><th>Flexibility opportunity</th><th>Business case existing</th></tr>
<tr><td>1086</td><td colspan="2">Norwood ZS 66kV bays for Creyke Rd and Greendale ZS</td><td>FY29-30</td><td>No</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">The eastern part of the Central Plains area is currently supplied by Hororata GXP. The ability of this GXP to supply higher loads or large scale distributed generation is limited. The Hororata GXP also breaches our Security of Supply Standard, see Table 6.4.3.</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">This proposal is to create new connections from the new Norwood ZS 66kV bus across to Hororata GXP. This project is to construct two new 66kV bays to facilitate two new circuit connections.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="4">The Norwood ZS 66kV bus has been designed and constructed with additional allowance for future circuit and transformer connections.</td></tr>
<tr><td>1087</td><td colspan="2">Greendale ZS 66kV bays</td><td>FY29-30</td><td>No</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">Greendale ZS has only a single 66kV circuit breaker for the transformer so is not readily equipped to be part of a closed-ring 66kV network.</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">This project proposes installing a new 66kV busbar and two new 66kV line bays to connect the existing line from Hororata and to accept a new line connection from Norwood ZS, see Project 1087.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="4">An alternative considered was to use a circuit breaker and a half layout reducing the additional HV equipment required by one circuit breaker bay, but the site would require complete reconfiguration negating any reduction in equipment purchasing costs.</td></tr>
<tr><td>1072</td><td colspan="2">Norwood ZS to Greendale ZS 66kV line</td><td>FY29-30</td><td>No</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">A new 66kV circuit is required to connected Norwood ZS to Hororata GXP via Greendale ZS.</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">This proposal is for a new 66kV line to be constructed from Norwood ZS to Greendale ZS inconjunction with the terminating switchgear bays at each line terminal. See Projects 1086 and 1087.</td></tr>
<tr><td>1073</td><td colspan="2">Norwood ZS to Creyke Rd ZS 66kV circuit</td><td>FY29-31</td><td>No</td><td>No</td></tr>
<tr><td>1245</td><td>Issue definition</td><td colspan="4">A key site to enable a stronger interconnection to the Hororata GXP supply area and the Norwood GXP is the Darfield township</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">This proposal is to construct a new 66kV circuit from Norwood ZS to the Darfield township.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="4">An underground cable is required for the first section of the new 66kV circuit out of Norwood ZS because the route is shared with the Norwood ZS to Greendale ZS line. This also facilitates an optimal 66kV bay layout at Norwood ZS.</td></tr>
<tr><td>1459</td><td colspan="2">Creyke Rd ZS – new 66/11kV substation</td><td>FY30-32</td><td>Winter</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">There is increasing load from the Darfield township and there are multiple large decarbonisation proposals that will exceed the capability of the Darfield ZS.</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">Multiple drivers indicate that a new site is required to replace the Darfield ZS. This proposal is the establishment of a new zone substation.</td></tr>
<tr><td></td><td>Remarks/alternatives</td><td colspan="4">The Darfield ZS 33 and 11kV switchgear is due for lifecycle replacement and the current site and switchroom is unsuitable for our modern standard equipment. The new proposed substation will be designed for 66/11kV, but may be operationally split between the Hororata 33kV and Norwood 66kV to aid construction and equipment availability.</td></tr>
<tr><td>1525</td><td colspan="2">Wards Rd, Darfield 66kV line</td><td>FY30</td><td>No</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">The new Creyke Rd ZS requires connection to the subtransmission line from Hororata.</td></tr>
<tr><td></td><td>Proposed option</td><td colspan="4">This project proposes extending the subtransmission line from Darfield ZS to meet the existing 66kV constructed line on Creyke Rd to form the Hororata ZS to Creyke Rd ZS.</td></tr>
<tr><td>1603</td><td colspan="2">Hororata ZS – 66kV busbar</td><td>FY31-33</td><td>No</td><td>No</td></tr>
<tr><td></td><td>Issue definition</td><td colspan="4">A new 66kV bus is required to facilitate Orion connection separation at Hororata GXP.</td></tr>
</table>

8.4.2.3 Lincoln area capacity and security programme

Investment drivers



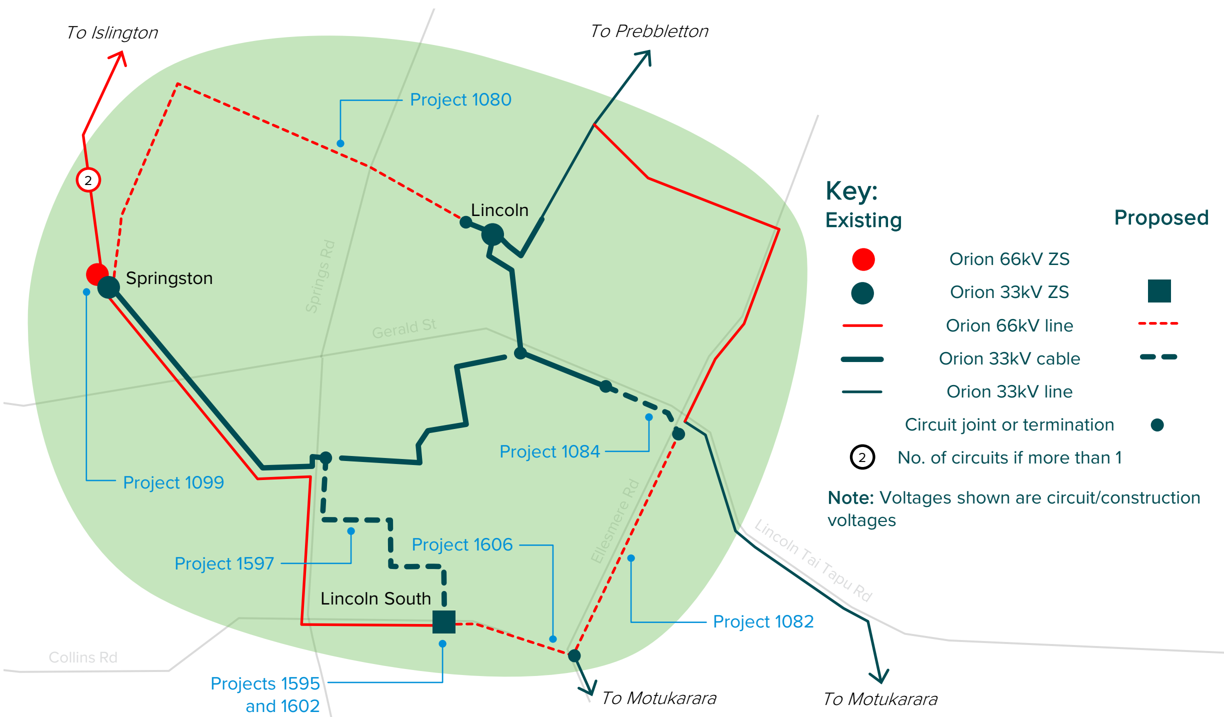
High residential subdivision growth in the Lincoln township has pushed the peak load of Lincoln ZS beyond the firm capacity. We have implemented a variety of traditional and non-traditional projects to mitigate the effects. This includes a major capacity and security upgrade at Springston ZS and the use of third-party flexibility services to reduce the peak demand of Lincoln ZS to within the seasonally adjusted site firm rating.

A new large residential and commercial greenfield development has been consented in the southern part of Lincoln township outside of the current zoned land. This development has plans for more than 1,700 new homes. Due to the location and weak distribution network in this area we have altered our development plan to construct a new zone substation as part of this subdivision to provide a new distribution network injection point.

Our 2023 AMP outlined the construction of a new Greenpark ZS to the east of Lincoln township that would have completely replaced the existing Lincoln ZS site albeit with more distribution supply capability. Due to the geographic location and size of the Lincoln South development a more suitable solution is to augment the existing supply points with the new Lincoln South substation.

For an overview of the projects in our Lincoln area capacity and security programme, see Figure 8.4.8 and Table 8.4.6.

Figure 8.4.8 Proposed Lincoln area capacity and security projects – subtransmission



8.4 Optioneering and proposals continued

Table 8.4.6 Lincoln area capacity and security projects

No.	Project title		Year	Flexibility opportunity	Business case existing
1099	**Springston ZS 66/11kV transformer upgrade**		**FY24-25**	**No**	**Yes**
	Issue definition	In FY24 a second 66/11kV transformer was due to be added to Springston ZS, but this won't provide any usable increase in firm capacity due to the original transformer bank being only 7.5/10MVA in size.			
	Chosen option	Change the existing T3 66/11kV 7.5/10MVA transformer to a new 11.5/23MVA transformer.			
806	**Gerald St cable**		**FY26**	**No**	**No**
	Issue definition	There is currently approximately 400m of 11kV overhead remaining on Gerald Street in Lincoln. This limits the capacity of the feeder, reduces the reliability for the Lincoln township customers fed from this feeder.			
	Proposed option	The remaining 11kV lines in Gerald Street (Lincoln) will be undergrounded as the sequence of reinforcement is completed.			
	Remarks/alternatives	This project is part of our reinforcement of the main road circuits in Lincoln township, including the removal of 11kV overhead lines and will be coordinated with Selwyn District Council works on and around Gerald Street.			
895	**Ellesmere Junction Rd 11kV reconductoring**		**FY26**	**Winter**	**No**
	Issue definition	The existing 11kV overhead circuit on Ellesmere Junction Rd severely limits the transfer capability between Springston ZS and Lincoln ZS.			
	Proposed option	An option is to reconductor the overhead circuit with a larger capacity conductor			
	Remarks/alternatives	The purpose of this project is to reduce the overall load on Lincoln ZS so greater use of flexibility could alter the need date for this project.			
1595	**Lincoln South – new zone substation**		**FY26-28**	**No**	**No**
	Issue definition	A substantial new residential development is consented for the southern area of the Lincoln township. This area has limited distribution network and roading to facilitate reinforcement from existing zone substations.			
	Proposed option	We propose constructing a new 33/11kV substation as part of the subdivision development.			
	Remarks/alternatives	We propose using the surplus ex Rolleston ZS 10MVA 33/11kV transformers as opposed to purchasing new ones. Although 66kV may be required in the future, the timing of this is extremely unknown so the most cost-effective method and lowest visual impact is to construct this substation with all switchgear and control equipment housed in a single low profile building like Motukarara ZS or Prebbleton ZS.			
1597	**Lincoln South ZS – subtransmission extension**		**FY26-28**	**No**	**No**
	Issue definition	Although the proposed new zone substation is adjacent to a 33kV subtransmission overhead line, there is insufficient capacity to meet the security requirements.			
	Proposed option	This option proposes cutting and extending the existing Springston ZS to Lincoln ZS 33kV cable into the new substation creating three connections to the 33kV subtransmission.			
	Remarks/alternatives	There are a variety of options that were considered but would require trenching through newly established subdivisions and/or establishment or easements through SDC drainage reserves. This option will mostly utilise trenches that will be part of the subdivision development.			

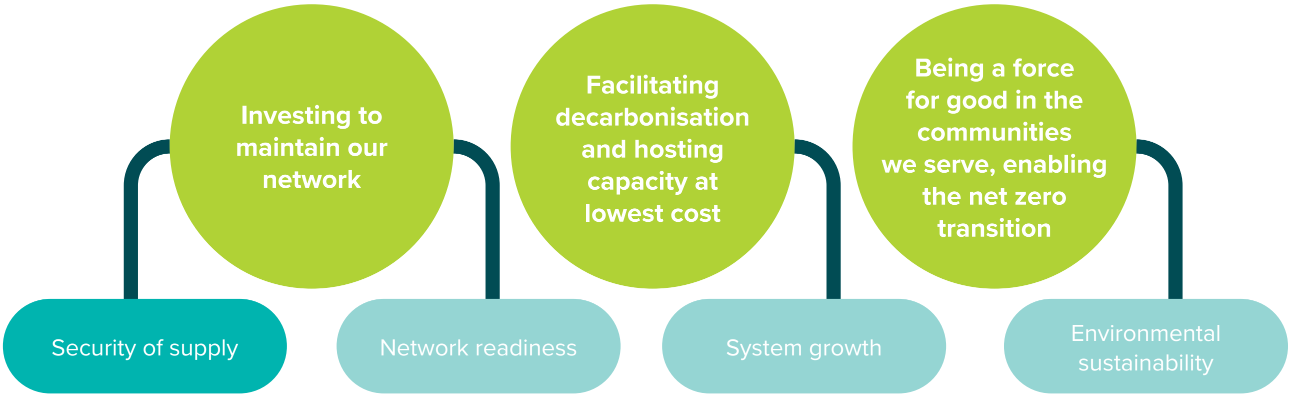
8.4 Optioneering and proposals continued

Table 8.4.6 Lincoln area capacity and security projects (continued)

No.	Project title		Year	Flexibility opportunity	Business case existing
1080	**Springston to Lincoln ZS 66kV line reconductor**		**FY27**	**Winter**	**No**
	Issue definition	With the increased loading on the 33kV network fed out of Springston ZS towards Lincoln and Banks Peninsula a single contingent event on the one of the other two feeders causes the Springston to Lincoln ZS overhead line to overload.			
	Proposed option	Reconductor the line to a higher capacity conductor.			
	Remarks/alternatives	This 33kV operated pole line has been reinsulated to 66kV as part of an asset lifecycle refurbishment project, but the conductor was not replaced. Area wide peak load reduction could be used to alter the need for this project.			
1084	**Edward St 33kV cable extension to Ellesmere Rd**		**FY27-28**	**No**	**No**
	Issue definition	The 33kV network in the Lincoln area requires reconfiguration to enable connection of the new Lincoln South substation and to ensure that the security is not compromised for customers supplied by Motukarara ZS and the Banks Peninsula 33kV network.			
	Proposed option	This project proposes laying a new 33kV cable down Edward St to meet the new overhead circuit on Ellesmere Rd, see Project 1082.			
	Remarks/alternatives	This project extends and utilises the 33kV cable that was laid in anticipation of the Greenpark ZS.			
1082	**Ellesmere Rd 66kV line**		**FY27-28**	**No**	**No**
	Issue definition	To ensure the meshed 33kV network operates effectively under nominal and contingent load flow situations, a new connection is required between Lincoln ZS and the overhead line on Collins Rd.			
	Proposed option	Build a new line down Ellesmere Rd to connect the new 33kV cable, see Project 1084, onto the overhead line on Collins Rd.			
	Remarks/alternatives	This line will be constructed with 66kV insulation levels but operated at 33kV at this stage.			
1602	**Lincoln South ZS 33kV switchboard**		**FY27-28**	**No**	**No**
	Issue definition	The new proposed Lincoln South substation, see Project 1597, requires connection to the subtransmission network.			
	Proposed option	This project will equip the building constructed under Project 1597 with 33kV indoor panels to enable connection of three circuits and two transformers.			
	Remarks/alternatives	This project was separated from the main substation project because the various 33kV options considered required different 33kV switchboard circuit connection numbers and configurations.			
1606	**Collins Rd 66kV line upgrade**		**FY32-33**	**No**	**No**
	Issue definition	The load on the Lincoln, Lincoln South, Motukarara ZS and Banks Peninsula ring has grown so a contingency on the Springston ZS to Lincoln South ZS leg causes a cascade overload failure.			

8.4.2.4 Region B subtransmission capacity and security programme

Investment drivers



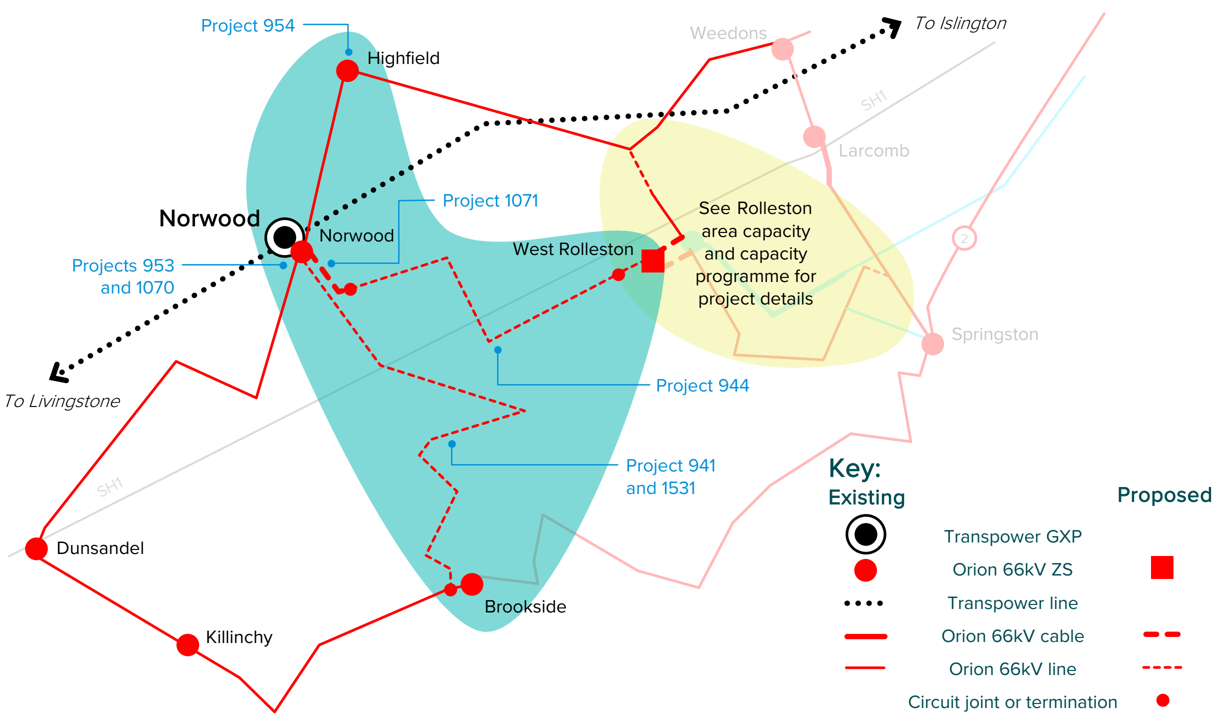
Continued residential and commercial growth in and around the townships of Rolleston and Lincoln, as well as growth from major customers, has been rapidly depleting the remaining capacity of the Region B 66kV subtransmission network, and is putting increasing pressure on the Islington 66kV GXP. A major customer in this area is also supplied from the Springston ZS to Hororata GXP Region B 66kV circuit, which is voltage drop and thermally constrained, so cannot accept any more load.

In FY24 the new 200MVA capacity 220/66kV Norwood GXP was commissioned. This new supply point will future proof the capacity for Region B and relieve the loading at our largest 66kV supply point at Islington GXP. To enable the connection of Norwood GXP into our existing 66kV subtransmission network, this programme of work builds out connections from the new GXP to adjacent substations.

Once established, the Region B network will be able to support further commercial, residential and process heat decarbonisation and electrification growth, as well as providing a strong connection point to the Grid to support utility-scale distributed energy resource projects.

For an overview of the projects in our Region B subtransmission capacity and security programme, see Figure 8.4.9 and Table 8.4.7.

Figure 8.4.9 Proposed Region B subtransmission capacity and security projects



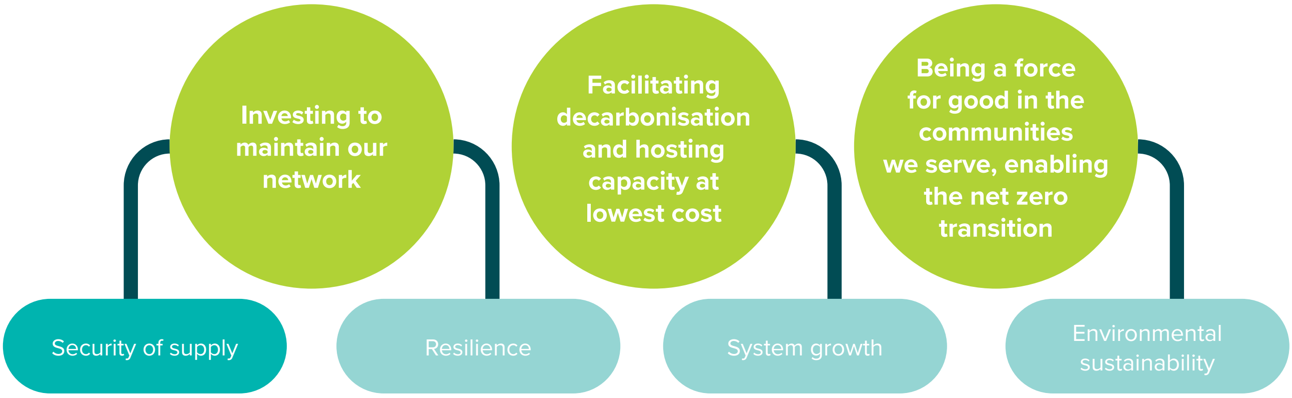
8.4 Optioneering and proposals continued

Table 8.4.7 Region B subtransmission capacity and security projects

No.	Project title		Year	Flexibility opportunity	Business case existing
941	**Brookside ZS to Norwood ZS 66kV line**		**FY23-25**	**No**	**Yes**
1531	**Issue definition**	Brookside, Killinchy and Dunsandel ZSs are now fed from the new Norwood GXP/ZS, but still retain the N-1 switchable 66kV supply to either Springston ZS or Hororata GXP. This configuration breaches our Security of Supply Standard because the load has grown to where an uninterrupted N-1 supply is required.			
	Chosen option	Project 941 completes the 66kV closed-ring uninterrupted N-1 supply back to the new Norwood ZS 66kV. Project 1531 installs and upgrades the protection scheme.			
	Remarks/alternatives	The new Brookside ZS to Norwood ZS 66kV line will initially be connected into the Brookside ZS to Killinchy ZS line to negate the need for a new 66kV bay at Brookside ZS.			
1615	**Norwood ZS transformer pad**		**FY25**	**No**	**Yes**
	Issue definition	The capacity upgrade work at Springston ZS, see Project 1099, has meant a 7.5/10MVA 66/11kV transformer requires a bunded storage area, but there are no spaces available.			
	Chosen option	The next location requiring a 7.5/10MVA 66/11kV transformer is the Norwood ZS 11kV supply, see Project 1070. This project installs a bunded pad at Norwood ZS to avoid the need to construct more transformer storage.			
953	**Norwood ZS 66kV line bays**		**FY26-27**	**No**	**No**
	Issue definition	66kV bays at Norwood 66kV need to be equipped to enable connection and supply of the West Rolleston ZS to Highfield ZS 66kV ring.			
	Proposed option	This project completes the construction of three 66kV line bays at Norwood ZS to allow for the connection of the new 66kV lines to Highfield ZS, West Rolleston ZS, and a bay for a 66/11kV transformer (Project 1070).			
1070	**Norwood 66/11kV zone substation**		**FY26-27**	**Summer**	**No**
	Issue definition	An existing major customer load has fully utilised the existing 11kV distribution capacity and is currently using a direct feed from Highfield ZS that is constructed at 66kV but operating at 11kV. The 66kV line is now required to form the 66kV ring for West Rolleston ZS.			
	Proposed option	The chosen solution is to construct an 11kV point of supply at Norwood ZS by installing a 66/11kV transformer and 11kV switchboard at the Norwood site to feed into the surrounding 11kV network.			
	Remarks/alternatives	This area is generally constrained in the summer time where irrigation and industrial coolstore load peak. A large-scale flexibility or DER scheme could negate the need for this.			
944	**West Rolleston ZS to Norwood ZS 66kV circuit**		**FY26-28**	**No**	**No**
1071	**Issue definition**	To enable the new Norwood GXP capacity to be utilised and to provide a firm supply to West Rolleston ZS a new 66kV circuit is required between the Norwood and West Rolleston ZSs.			
	Proposed option	These projects form a direct link from Norwood ZS to West Rolleston ZS via a 66kV cable out of Norwood ZS (Project 1071) and extended onto West Rolleston ZS with a new 66kV line – see Project 944.			
	Remarks/alternatives	A 66kV cable is required for the first section because this part of the route is shared with the Norwood ZS to Brookside ZS 66kV line.			
954	**Highfield ZS 66kV line bays**		**FY27-28**	**No**	**No**
	Issue definition	Highfield ZS is currently fed on a 66kV spur supply and has only one 66kV CB there for the transformer protection, but the Norwood ZS to Highfield line requires switchgear to terminate into.			
	Proposed option	This project installs two new 66kV line bays at Highfield ZS, and creates a new 66kV busbar, to allow for the connection of the new 66kV line from Norwood ZS.			
	Remarks/alternatives	The Highfield ZS was designed with future expansion to three 66kV CBs but constructed with one.			

8.4.2.5 Region A subtransmission capacity and security programme

Investment drivers

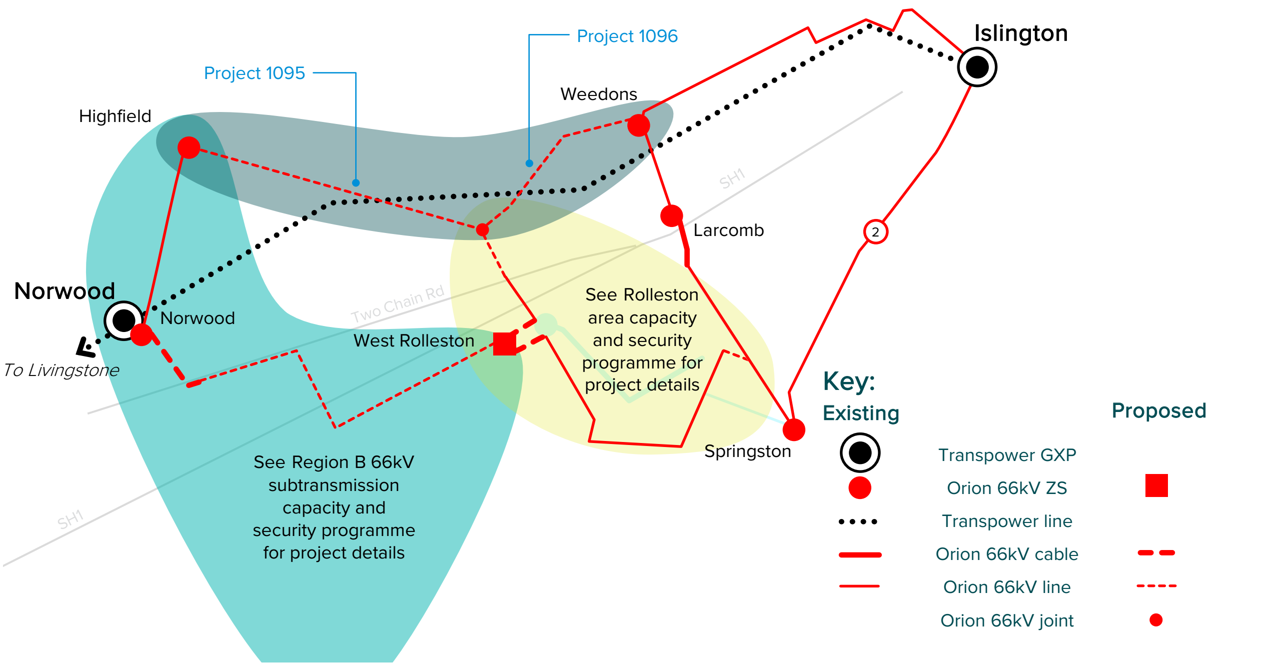


Our largest GXP, Islington 66kV, is forecast to meet or exceed its firm capacity at the end of the 10-year AMP period. We anticipate that as more decarbonisation of transportation and process heating occurs the capacity of Islington 66kV GXP will be reached sooner. Rather than putting more dependency on Islington 66kV GXP by introducing more capacity at this site, we will look at opportunities to increase our 66kV subtransmission resilience by strengthening ties to enable offload capability to adjacent GXPs.

The projects in Table 8.4.8 enable Larcomb and Weedons ZSs to be offloaded and fed from the Norwood GXP by reinforcing or thermally uprating the capacity of existing lines.

For an overview of the projects in our Region A subtransmission capacity and security programme, see Figure 8.4.10 and Table 8.4.8.

Figure 8.4.10 Proposed Region A subtransmission capacity and security projects



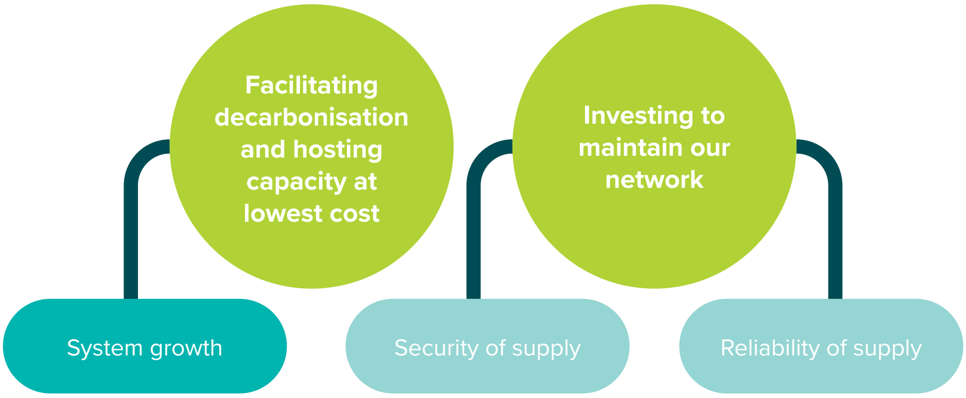
8.4 Optioneering and proposals continued

Table 8.4.8 Region A subtransmission capacity and security projects

No.	Project title		Year	Flexibility opportunity	Business case existing
1095	**Wards Rd 66kV line reconductor**		**FY28**	**No**	**No**
	Issue definition	The Norwood GXP – Highfield ZS – West Rolleston ZS 66kV ring is limited in its capability to carry Weedons and Larcomb ZS due to the existing overhead conductor on Wards Rd.			
	Proposed option	Reconductor the 66kV line on Wards Rd to a larger capacity and re-rate to a higher maximum design temperature.			
	Remarks/alternatives	Expedites using spare Norwood GXP capacity to mitigate emerging Islington GXP constraint.			
1096	**Highfield ZS tee to Weedons ZS 66kV line thermal upgrade**		**FY28**	**No**	**No**
	Issue definition	Islington GXP is approaching the N-1 limit. Weedons and Larcomb ZS cannot be offloaded due to a thermal constraint on an existing line section.			
	Proposed option	To facilitate the offloading of Weedons and Larcomb ZS onto Norwood GXP the existing 66kV line from the Kerrs and Wards Rd intersection to Weedons ZS will be thermally uprated.			
	Remarks/alternatives	Re-rating the line can be achieved by minor clearance increases and is far more cost-effective than reconductoring the line as this would require the entire line to be rebuilt.			

8.4.3 Other HV projects

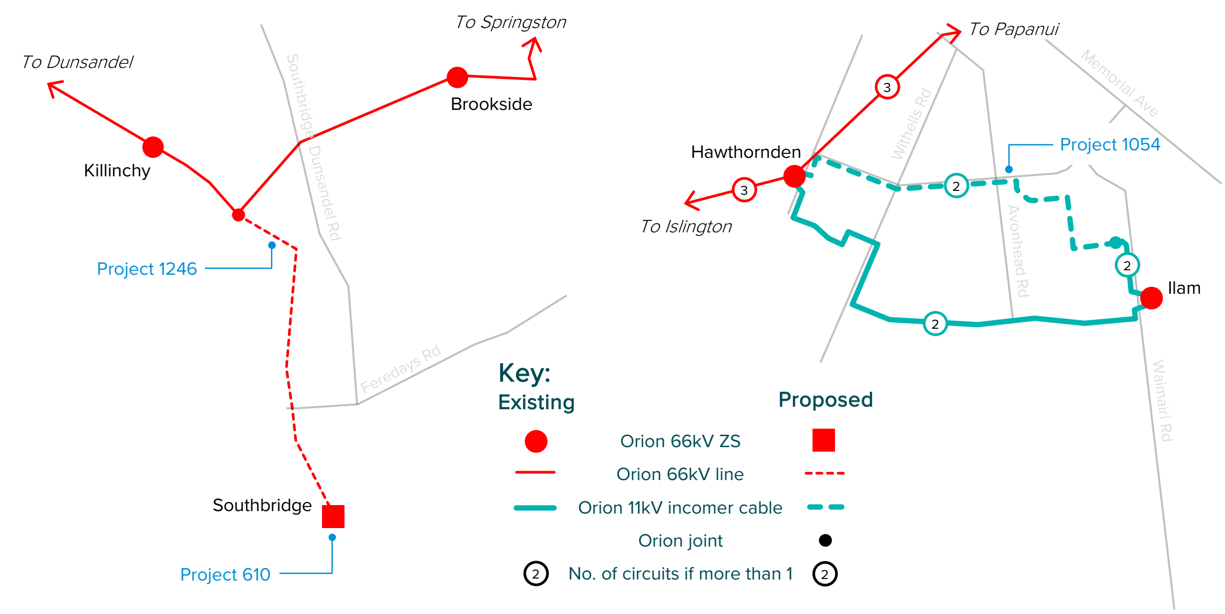
Investment drivers



These projects are reconfigurations or reinforcements of the subtransmission and 11kV distribution system across Orion's network. We have identified them through monitoring of 11kV feeder loadings and regular review of our zone substation contingency plans. These projects are across both the Region A and B of our network and are driven by system growth nominal capacity or security of supply contingency constraints.

Projects that have a developed concept are shown in Table 8.4.9 with the proposed location of the subtransmission specific projects shown in Figure 8.4.11.

Figure 8.4.11 Proposed other HV projects – subtransmission



8.4 Optioneering and proposals continued

Table 8.4.9 Other HV projects

No.	Project title		Year	Flexibility opportunity	Business case existing
1545	**Duvauchelle ZS CB123 reliability improvement**		**FY25**	**No**	**Yes**
	Issue definition	The township of Akaroa is supplied primarily from one overhead circuit from Duvauchelle Zone Substation. This line has a secondary purpose supplying load in multiple bays via spur connections off the main circuit. Faults on these spurs greatly reduce the reliability to the Akaroa township.			
	Chosen option	This project installs additional switchgear to enable self-isolation of faults and the ability to sectionalise and resupply the bulk of the customers after a fault remotely.			
1613	**Hororata distribution voltage improvement**		**FY25**	**No**	**Yes**
	Issue definition	The combination of a dry FY24 summer and step changes in loading is causing power quality issues for customers on Leaches Rd, Rakaia Terrace.			
	Proposed option	Install a Statcom to provide steady-state and fast-acting dynamic voltage support at our undeveloped Windwhistle substation site.			
	Remarks/alternatives	We considered reconductoring and the installation of a voltage regulator. We will utilise an existing Statcom and the proposed configuration will enable switchable support to two different feeders.			
913	**Heathcote Lyttelton 11kV reconfiguration**		**FY26**	**No**	**No**
	Issue definition	In FY20 a new cable was installed through the Lyttelton road tunnel to increase the supply resilience to the township of Lyttelton and the port. Presently the full capacity of the cable cannot be utilised due to the network configuration on the Heathcote side of the supply.			
	Proposed option	Install and commission new switchgear and reconfigure the 11kV network on the Heathcote supply side of the tunnel cable.			
	Remarks/alternatives	This project installs equipment on an existing Orion site and is the most cost-effective solution to make use of the full capacity of the new 11kV through the tunnel.			
1569	**Sparks Rd 11kV undergrounding**		**FY27**	**No**	**No**
	Issue definition	A high capacity direct 11kV connection existing between Hoon Hay ZS and Halswell ZS. Ideally this circuit could be better utilised, but the reliability is much worse than the surrounding network, which is underground, due to exposure to environmental interference.			
	Proposed option	Underground the overhead circuit including reconfiguring the connections on to it.			
	Remarks/alternatives	This project could be used in conjunction with others to defer the need to install a third transformer at Halswell ZS.			
1093	**Innovation Dr 11kV reconfiguration**		**FY28**	**Summer and Winter**	**No**
	Issue definition	Load growth in the Calder Stewart and Ngai Tahu commercial and industrial subdivisions in between Main South Road and Shands Road is stretching the existing distribution capacity between Moffet ZS and Hornby ZS. Part of original distribution design for the area no longer matches the trunk feeder architecture due to changes in customer requirements.			
	Proposed option	This project will reconfigure some cables on Innovation Drive so that the feeders better align with the trunk feeder architecture and allow for the future commercial and industrial growth in the area.			
	Remarks/alternatives	This is the most cost-effective traditional network solution to provide capacity for the future commercial and industrial growth in the area. Non-traditional alternatives will be assessed closer to the need date as the future value of these technologies and services is unknown.			
1054	**Ilam ZS 11kV incomer cables**		**FY32-33**	**Winter**	**No**
	Issue definition	Ilam and Fendalton ZS will reach their firm capacity.			
610 1246	**Southbridge 66kV substation and 66kV line extension**		**FY33-34**	**Summer and Winter**	**No**
	Issue definition	Load in the area will exceed the network capacity at both 11kV distribution and 33kV subtransmission level.			

8.4.4 400V LV programmes of work

The following section outlines our network development LV projects and programmes of work planned for the next 10 years. With ongoing residential housing intensification in Christchurch, and electric vehicles and solar generation become more prevalent, the capability of our 400V LV network is becoming increasingly important.

Our investment strategy for our 400V LV network is to use new information and technology to optimise the throughput of energy across our existing network, reducing the need to reinforce it.

The new information on our 400V LV network will come from two primary sources: capital investment in LV monitoring, and receiving network data from the owners of smart meters.

To optimise our 400V LV network we will use smart systems to assess information on power flows and quality down to LV feeder level and dynamically alter the loadings on these feeders to increase their usable capacity. Our use of smart technology will release currently latent and unused capacity from the network and optimise utilisation of existing LV feeders. The released network capacity can be used to connect more EVs and new housing, without building new, expensive network.

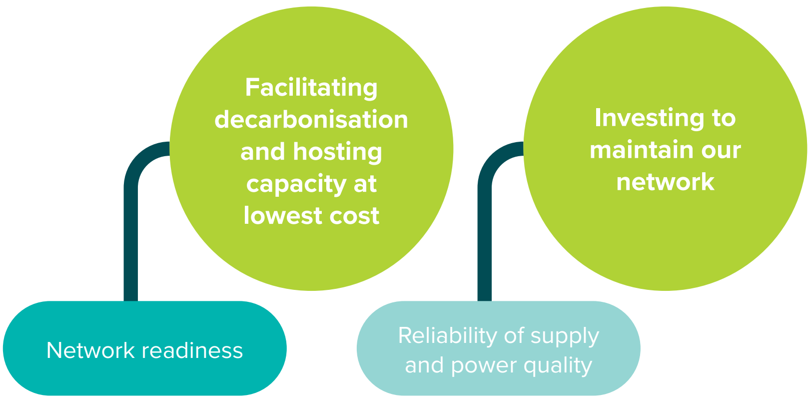
We will also use other methods to ensure we do not build new low voltage network unnecessarily, including:

- increasing the maturity of our future energy scenarios and modelling capability to improve our confidence in future demand, flexibility, and network constraints
- optimising the operation of the current network through variable conductor ratings and flexible customer capacity arrangements
- incentivising our customers and communities to help alleviate network constraints using energy storage and demand side flexibility - where lower cost than network augmentation
- encouraging the best use of vehicle-to-grid and vehicle-to-home technology for electric vehicles with the goal of lowering network peaks or solving other network constraints like voltage issues
- using non-traditional network solutions, like Statcoms for voltage regulation, as a lower cost solution to traditional capacity upgrades

Through a combination of approaches, we will get the most out of our assets and minimise the investment required in our traditional low voltage network. For background on the proactive LV reinforcement investment that will still be required, given the sheer size of demand increase from EVs, population growth, and intensification of housing, see Section 2.

8.4.4.1 400V LV monitoring

Investment drivers



LV monitoring enables us to observe the use of power in near real time, at street level. This low voltage monitoring samples power flows and voltage at 10-minute intervals, generating a wealth of data that will allow us to see and respond to changes of activity on the network. Having visibility of how our network is being used at this granular level will also help us to provide customers with a more flexible, dynamic range of choices for managing their energy needs. See Section 7.7.2 for benefits of improving LV network visibility.

Analysing the data from these monitors is enabling us to develop a better understanding of baseline LV demand and will enable us to see how it changes as adoption of EVs, solar PV, battery storage and energy sharing become more prevalent, and patterns in customer behaviour emerge.

To increase the visibility and understanding of our LV networks, we are in the process of installing approximately 1,600 LV monitors by FY26. These monitors are being targeted towards sites with a higher risk of constraint, as forecast by the research we have completed with the

EPECentre. This number of monitors approximates to 13% of the total number of transformers on our network. It aligns with the ‘expansion scenario’ described by Sapere Consulting in its ‘Low Voltage Monitoring’ guideline produced for the Electricity Networks Association (ENA) in 2020.

The data captured from these monitors, in combination with access to LV smart meter data, will enable us to gain a greater understanding of the utilisation and power quality of the network that connects to more than 98% of our customers.

Table 8.4.10 400V LV monitoring

No.	Project title	Year	Flexibility opportunity	Business case existing
884	**Low voltage monitoring programme**	**FY20-26**	**No**	**Yes**
	Issue definition	New technologies such as solar panel, photovoltaic generation, battery storage and electric vehicles have the potential to significantly change customer behaviour and we currently have very limited real-time visibility of our low voltage network, making it difficult to identify potential constraints.		
	Chosen option	We have initiated a programme of works to install LV monitors at strategic locations on our LV network so that we can better respond to and understand the potential change of customer behaviour.		
	Remarks/alternatives	To maximise efficiency, the equipment will be only installed at higher risk distribution substations that serve more than one customer and have a minimum rating of 100 kVA for pole mounted sites or 200 kVA for ground mounted sites.		

8.4.4.2 Smart meter information gathering

While the 400V LV monitoring programme will provide us with excellent information on our network’s performance at the start of a feeder, information from further downstream is required to fully assess the performance of our LV network.

The quality of electricity supply varies depending on where a home is located along the length of a feeder. For example, the last few houses on a line may be more susceptible to voltage performance issues.

To monitor performance of this aspect of our service, we will require information from one of two sources:

- LV monitors installed further down the feeder on our side of the customer’s point of supply, for example on the last power pole or in the distribution box, or
- existing smart meters installed on the meter board at the customer’s home

Our preference is to use smart meters already installed on homes as this is likely to be the most cost-effective and efficient option for our customers, compared to Orion installing new standalone monitors.

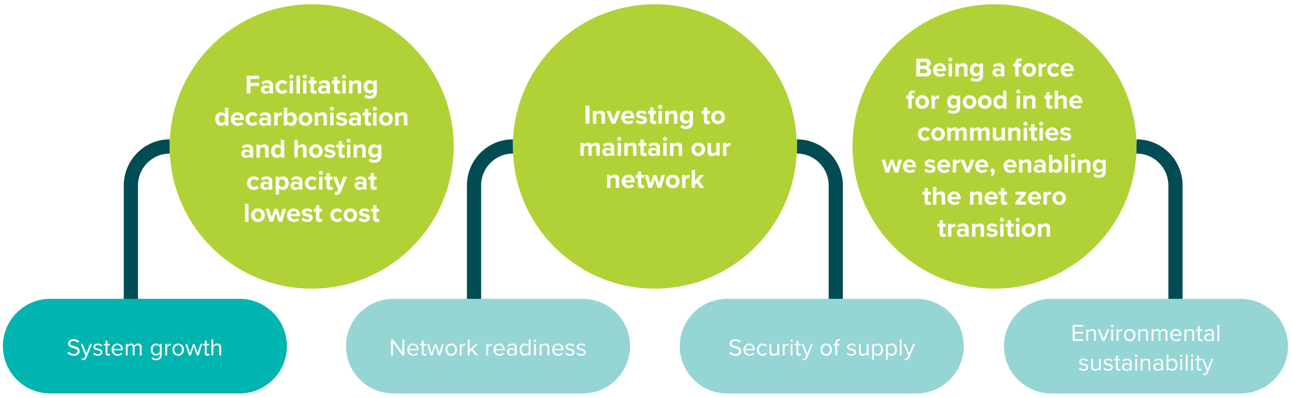
In November 2023, Orion became the first electricity distribution business in the country to access operation smart meter data from Bluecurrent (formerly Vector Metering), the largest smart metering provider in New Zealand. Under this agreement, Orion will gain access to operational data on the performance of its network right up to the boundary of around 90% of its customers. Each day we will receive around 500 million data readings from Bluecurrent.

This smart meter information will help Orion to improve the optimisation of our network as our region’s demand for electricity increases with decarbonisation. This data will also help us prioritise where we should install real- time monitoring. An allowance for procuring this additional smart meter information has been incorporated in our operational expenditure.

This smart meter information will help Orion to improve the optimisation of our network as our region’s demand for electricity increases with decarbonisation.

8.4.4.3 Proactive 400V LV reinforcement

Investment drivers



LV network issues are currently not easy to identify due to high volume, low visibility and data gaps which make it difficult to model on a regular basis. Operating within these current limitations we have formulated a threshold-based system to classify LV constraints into low, medium, and high priority. That system has generated our present LV reinforcement programme. As our LV data strategy comes to life, it is envisaged that LV constraints will be investigated in detail on a targeted area by area basis, to develop project scopes for each reinforcement.

Our initial studies indicate that by 2030 a 30% uptake of light EVs could impact approximately 13% of our LV networks across residential areas. The effects will be wide ranging but will predominantly impact the thermal ratings of our LV underground cable and overhead line networks. It is also anticipated that our overhead lines will be 1.5x more likely to be constrained than underground cables due to their asset age and lower thermal capacity.

Table 8.4.11 Proactive LV reinforcement

No.	Project title	Year	Flexibility opportunity	Business case existing
1277	**Proactive LV reinforcement programme**	**FY25-34**	**Summer and Winter**	**Yes**
	Issue definition	Modelling of the LV network indicates that there are several constraints existing which will be exacerbated by EV load and housing infill.		
	Chosen option	Investigate issues and initiate proactive reinforcements to reinforce areas of the network which have been identified as constrained.		
	Remarks/alternatives	Where possible, optimisation using network switching and phase balancing will be performed before reinforcement. Reinforcement could be traditional or non-traditional such as and voltage support or DER. The feasibility of these solutions will be determined on a case-by-case basis.		

9

How we deliver

Photo: Connetics and Isaac Construction installing new, more resilient underground electric cabling in Orion's network along Ferry Road.

Contents

9.1 Introduction

This section describes our:

- approach to addressing our future workforce resourcing and capability needs, at Orion and sector level
- key philosophies, policies and processes that enable us to deliver our works programme and AMP objectives
- way we go about delivering our programme of work and manage relationships with our service providers to consistently deliver our work safely, cost effectively and efficiently
- approach to managing the factors impacting delivery of our programme of work

To adequately prepare for decarbonisation in our region and to ensure we continue to deliver a safe, reliable and resilient network, we have projected significant levels of network investment over the period of this 10-year AMP. We will need to address the long-term workforce size and capability shortages that are anticipated. To enable Orion to meet the needs of the future, it will be necessary for us to lift our internal and external workforce capability and size, and successfully manage supply chain and climate change challenges to deliver our ambitious and necessary plan.

9.2 Meeting our current and future resourcing needs

With the significantly increased programme of works we and the rest of New Zealand's electricity sector are anticipating in the next few years, there is sector-wide consensus that the industry workforce will need to increase greatly in size. More complexity in the distribution system will also call for greater expertise and new skills. This is likely to coincide with a time of increasing demand for skilled electricity workers internationally as other nations transform their networks to support decarbonising their economies. More extreme weather events, locally and globally, and geopolitical unrest will continue to have an impact on workforce availability, as networks are rebuilt.

We acknowledge it will be a challenge to adequately provide the skilled workforce to deliver our plan as our sector competes nationally and internationally for resources to deliver decarbonisation.

We acknowledge it will be a challenge to adequately provide the skilled workforce to deliver our plan as our sector competes nationally and internationally for resources to deliver decarbonisation.

To address the challenge of whether we can deliver on our commitment to decarbonisation in the decades ahead, our sector recognises the need to develop new ways to grow our workforce's capability and size.

9.2.1 Workforce size and capability gaps

Alongside others in the sector, Orion is in the process of identifying the long-term workforce size and capability gaps to support the growing size and complexity of our network and the infrastructure development projects to deliver a low-carbon, electrified economy. While this is an evolving situation, the types of talent we anticipate needing more of in the latter years of this AMP period are:

- Robotics and AI experts
- Business analysts
- Information systems developers
- Data analysts
- Power system engineers
- Control system engineers
- Project managers
- Field crew

Orion has 311 FTE employees as at the end of FY24, and we have not forecast a significant increase in employee numbers in the next five years. Two factors help to balance out Orion's workforce needs:

- **Improvements in operational efficiency** – streamlined processes and new technologies may reduce some workforce requirements
- **Our Project Management Office (PMO) and Primary Service Delivery Partner (PSDP) contracting model** – provides Orion with a committed partner in addressing future workforce needs. The PMO also creates a consistent flow of work to keep the service provider market optimised with a high level of utilisation.

9.2.2 Building external capability

We share our future works plan with Connetics, our Primary Service Delivery Partner (PSDP) and Project Management Office (PMO), and key service providers so they can prepare for increased workloads and the need for new skills in advance. However, we recognise the need to grow our industry's capability and workforce size is pressing, significant, and is a shared responsibility. Orion is working with others in our sector to explore ways to build external capability, including:

- **The PMO** – is working with service providers to identify workforce gaps and canvassing their provisions for apprenticeships to grow the workforce in numbers and capability in areas of future need.
- **Strategies to increase the attractiveness of the sector** – including enhanced talent acquisition practices to maximise our reach into the labour market; support of GirlBoss to close the gender gap in science, technology, engineering, maths, leadership and entrepreneurship.
- **Cross sector collaboration** – we are in discussion with industry bodies, training organisations and government agencies to develop ways to address this issue.
- **Facilitating skills portability** – continuing to work with Te Pūkenga, Northpower, Genesis Energy, Ministry of Business, Innovation and Employment, the New Zealand Qualifications Authority and Waihangara Rau on industry designed learning pathways for the energy sector to share.
- **Supporting other industry competency initiatives** – Ara Trades Innovation Centre, which has an electricity distribution trades training centre, and University of Canterbury's Power Engineering Excellence Trust.
- **Established an Energy Hub and Energy Futures Lab** – to facilitate sector collaboration, including Energy Exchange events and innovation projects.

We are developing new workforce skills and attributes as we move to a more automated and digitised workplace.

9.2.3 Building our internal workforce capability

The way we work is changing. From digitisation, automation of customer information through our new Customer Relationship Management system to improvements in our spatial data analysis and line surveys using drones, Orion is focussed on implementing ways to simplify and make our processes more efficient. See Section 4.

Our workforce is adapting to meet the needs of new service offerings and as innovation changes how work is performed. We are developing new workforce skills and attributes as we move to a more automated and digitised workplace. We are also proactively implementing changes in work practices that are enabling us to work smarter and utilise our workforce more efficiently.

A range of initiatives are underway to build our team's capability and capacity to deliver our work programme to support Orion's strategic focus on facilitating decarbonisation and creating the preferred workplace, see Section 4.

9.3 How we deliver our works programme

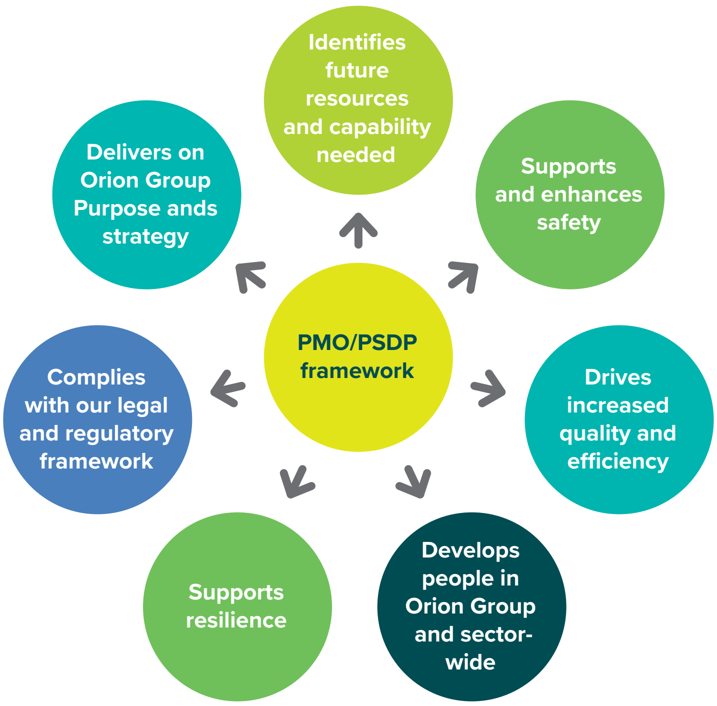
For construction and maintenance services of our overhead, substation and underground assets, we have an arms-length Project Management Office (PMO) and Primary Service Delivery Partner (PSDP) contracting model. Connetics undertakes the role of PMO and plans and contracts work from several service providers, including Connetics which is our PSDP. The PMO/PSDP relationship enables a long-term partnership approach rather than a short-term transactional approach through a contractual framework that incentivises the long-term development and maintenance of the resources and capabilities Orion needs. The framework also enables workforce optimisation – crucial as supply chain issues impact project delivery timeframes.

The PMO uses several procurement methodologies for assessing and awarding works and apply unit rates where work is repeatable.

Our framework for contracting significant network maintenance and construction work enables Orion to meet a range of outcomes more effectively and efficiently, see Figure 9.3.1.

For construction and maintenance services of our overhead, substation and underground assets, we have an arms-length Project Management Office (PMO) and Primary Service Delivery Partner (PSDP) contracting model.

Figure 9.3.1 Outcomes of Orion's contracting framework



9.3 How we deliver our works programme continued

Orion's Procurement team maintains the contract and service level measures for Connetics in its role as our PMO, and in 2023 we established the Oversight Group to monitor KPIs of how the model is performing against the expected outcomes.

Our Network Delivery team is responsible for the works programming and delivery of our annual work plan in conjunction with our PMO, supported as appropriate by our other teams. The team establishes the work package for each project, including design, costing and planning. It sets and monitors the achievement of service levels and agreed costs established in conjunction with Orion's Network Planning team against the AMP budget, and formalised when the project is awarded to a service provider.

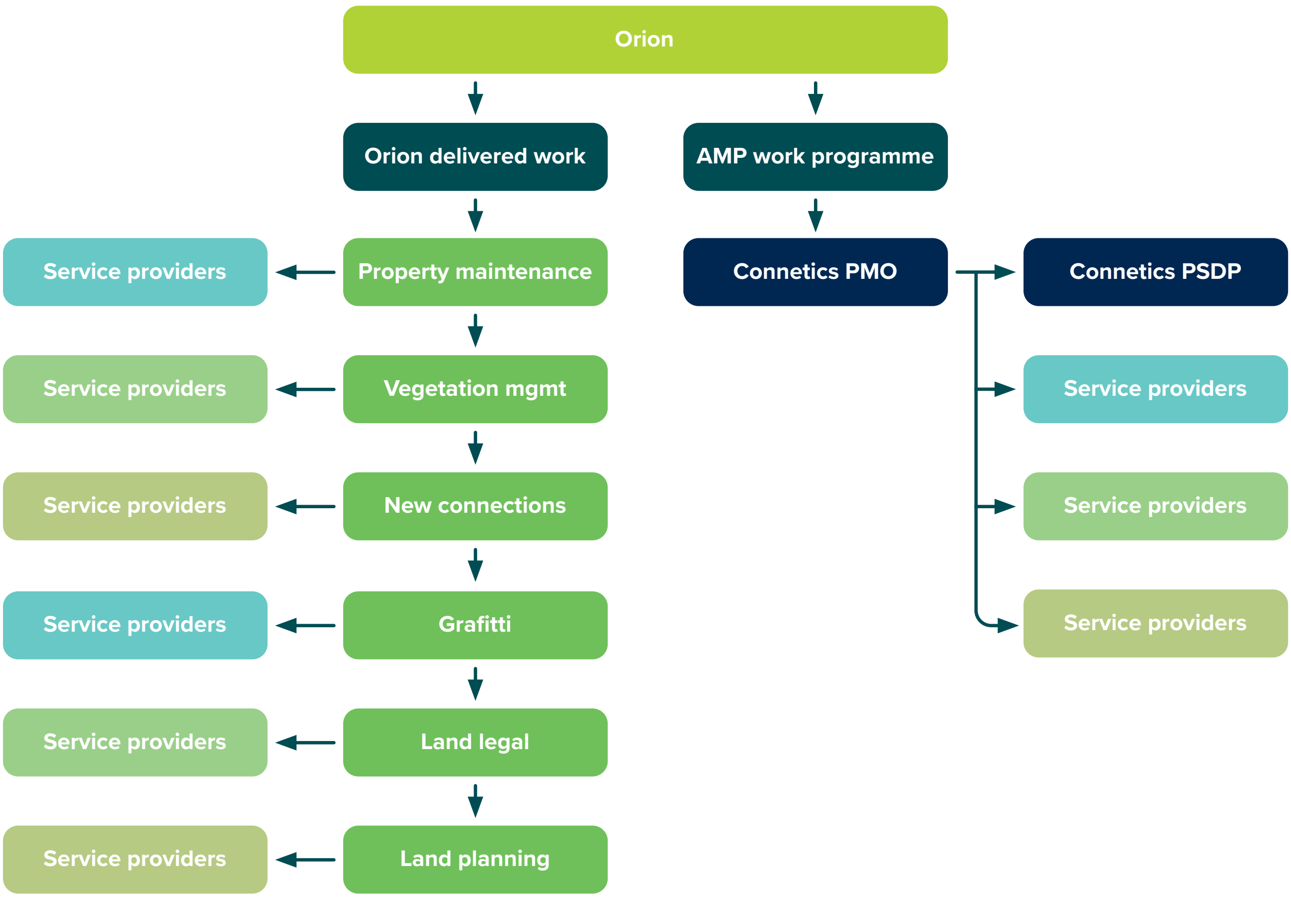
Orion also contracts service providers directly to undertake work supporting our operations, including property related services, management of vegetation threatening our network and customer initiated works such as new connections, both residential and commercial.

Our other in-house teams, set out in Section 4 of this AMP, provide the vital business, customer engagement and information support functions that enable the successful delivery of our works programme and a highly responsive service to our customers and community.

Our Works Management information management system supports administrative processes – including tenders, contracts, audit information and financial tracking. When implemented, our new Integrated Asset Management system will provide a significantly enhanced and more efficient service to support these processes. See Section 4.

For our contract delivery framework see Figure 9.3.2.

Figure 9.3.2 Orion contract delivery framework



9.4 Managing our service providers and field operations team

Orion directly engages contractors and consultants, who we call service providers, to deliver a range of services to support our administration of the network, and access to it. Connetics' PMO contracts with service providers to undertake our AMP programme of work on network development, replacement and maintenance. See Figure 9.3.2.

Our service providers don't have direct network management responsibilities for our assets – we engage them for specified scopes of work or for contracts over specific periods to meet the needs of our asset management objectives.

The key objective of our contractual relationships with service providers is to ensure the safety and quality of work of both the people involved and the work being delivered. Through our Bounds of Service clause, we set the capabilities required to ensure those working on projects do not go beyond the bounds of their competency. Our contracts also ensure services and materials are delivered on time, at an agreed cost and to specified requirements. Orion contracts are mainly founded on AS/NZS standard conditions for capital, maintenance, and emergency works contracts.

When special circumstances arise, for example a project that requires specialist skills, we may invite other suitably experienced and competent service providers to tender for the work.

We welcome expressions of interest from suppliers who wish to become authorised service providers for our network, and we have a process that allows for this. We maintain a service provider register which details the work categories that can be undertaken by each provider – and we audit those providers against their Bounds of Service at appropriate intervals and times to ensure they still comply with our requirements and specifications.

We monitor our service providers by work types on an ongoing basis to ensure our overall service provider competence, capability and health and safety objectives are being met.

9.4.1 Prioritising our works programme

Our Network Delivery and Network Transformation and Investment teams together prioritise our large customer-initiated works and major network development projects and maintenance programmes using our prioritisation process, set out in Section 6. The Orion network development projects we plan to undertake over the next 10-year period are set out in Section 8, and our replacement and maintenance programmes are set out in Section 7.

As a result of supply chain issues, shifting customer lead-times and the unpredictability of weather events, we have, by necessity, become more flexible and agile in our project planning and prioritisation. We regularly review and adjust our plans during the year to ensure a consistent workflow for our service providers.

We regularly review and adjust our plans during the year to ensure a consistent workflow for our service providers.

9.4.2 Resourcing for emergency works

We have contracts in place with our emergency service providers to also support our field operations team for urgent work – for example, due to weather events, network failure or safety reasons.

9.4.3 Our field operations team

Orion has an in-house team of 20 network field operators who are our first responders to power outages and emergencies on our network. This team makes the network safe following an event and undertakes switching to restore power where possible and to ensure crews working on Orion's network can do so safely. Our field operators also undertake minor repairs such as fixing damaged service lines, and LV pole fuses.

Orion's field operators are the eyes and ears of our Network Control Centre, equipped with drones to help locate equipment faults on our overhead lines. They are assigned to specific metro and rural areas of the network which they come to know well, with many living in the regions they serve, recognised as important members of their community.

Field operators also manage our fleet of generators and are responsible for deploying them effectively to maintain services to as many customers as possible during major projects or longer-term outages.

The work of this team is directed via multiple channels. They work closely with the Orion Control Centre and Customer Support teams which identify the need for power restoration or emergency work. For scheduled programme projects, they liaise with the Release Planning and Network Delivery Teams, the PMO and service providers to assess and deploy the switching and generator support needed.

Orion's field operators are the eyes and ears of our Network Control Centre.

9.5 Good procurement practice

We have a variety of ways to procure equipment and services to give Orion and our service providers flexibility in contract options and conditions. The five Government Procurement Principles guide our actions, see Figure 9.5.1. We aim to have fair and transparent procurement processes that are free from fraud and impropriety, and are sustainable from economic, risk, legal, community and environmental perspectives.

We follow good procurement practice by:

- procuring fit-for-purpose goods and services
- considering whole-of-life costs of goods and services when procuring
- being cost conscious and considering value for money
- identifying, assessing and managing our procurement risks – financial and non-financial
- managing and mitigating any potential conflicts of interest in an open and collaborative manner
- complying with our legal and contractual obligations
- continuous improvement
- ensuring consideration of sustainability and social outcomes are included

Figure 9.5.1 Government Procurement Principles

9.5.1 Procurement of equipment

Tenders are our preferred method of engagement for the supply of major equipment. We consider the benefits of all tendering models for each major procurement to ensure the best outcomes for our network and our stakeholders. We assess tenders for equipment supply following a robust assessment using weighted attributes that include value for money, technical support, sustainability, surety of supply, environmental or social benefits, experience and reputation.

We aim to maintain fair and positive working relationships with our equipment suppliers. We are conscious Orion is a smaller player in an increasingly competitive international market for energy sector equipment.

9.5.2 Robust documentation ensures delivery to expectations

Orion thoroughly documents its policy and expectations for contracting and procurement to ensure a consistent, fair and reliable approach. The key policies and guidelines set the expectations and standards for our people and service providers to expediently deliver our AMP and asset management objectives are listed in Table 9.5.1.

We are conscious Orion is a smaller player in an increasingly competitive international market for energy sector equipment.

Table 9.5.1 Documentation of requirements and policies related to contracting and procurement

Document	Describes
Works General Requirements	Sets the overarching expectations on our service providers, that: • work shall be carried out safely, on time and cost efficiently, while ensuring customer satisfaction • only authorised personnel may undertake work on our network • service providers shall have appropriate management systems to deliver contractual obligations • the preferred methods and controls to plan, execute, monitor, control and close out works
Emergency Works	Ensures we have dedicated resources available to restore power to the network in an emergency, or severe weather event. Outlines the up-front resources and contingency measures we require service providers to always have.
Contract Performance **Incident Reporting** **Hazard Management**	Documents which set out the expectations and procedures to be followed for these critical performance and safety matters.
Procurement Policy	Sets out the expectations for employees relating to all Orion procurement activity that ensures compliance with practice outlined in the Orion Procurement
Procurement Manual	Provides guidance to Orion personnel on the expectations and procedures involved with the procurement of all goods and services.
Delegations of Authority Policy	Empowers our people to make business decisions using appropriate expertise and experience, within an efficient, transparent framework, and supports our contracting model and our procurement framework.
Fraud and Theft Policy	Sets out the arrangements in place within Orion for the prevention, deterrence, detection and investigation of fraud and theft.

9.5.3 Audit and performance monitoring

We audit our contract delivery process using an audit management guide based on an AS/NZS standard, and we have a dedicated team, supported by external experts as appropriate, for this.

Our audit process allows for the identification of health and safety hazards, and contractual or technical non-conformances. We review longer term contracts for continual performance improvement and cover new initiatives as they arise. We monitor our contract performance against our conditions of contract.

To continually improve our reliability and resilience in the face of extreme events, in 2023 Orion completed the Resilience Management Maturity Assessment Tool (RMMAT) for the first time.

Our key objective when monitoring contract performance is continuous improvement including:

- enhanced collaborative and positive relationships with our service providers
- consistent reporting and tracking of contract performance indicators
- the provision of information that allows for reporting, benchmarking and trend analysis
- enhancing our customer experience by ensuring our service providers are focussed on customer satisfaction

In 2023 we commissioned Deloitte to complete a business assurance report on our procurement process and expect to implement enhancements as a result of this report.

To continually improve our reliability and resilience in the face of extreme events, in 2023 Orion completed the Resilience Management Maturity Assessment Tool (RMMAT) for the first time. For the results see Section 5.10.5.

The insights gathered from these assessments help us identify any systemic issues with our asset management processes and operational factors impacting customers. Along with other aspects of our extensive engagement with our community and stakeholders, they help define the strategic direction of our Asset Management Plan.

9.5.4 Improving our contracting and procurement processes

We have recently implemented several significant improvements to our contracting and procurement processes. These are streamlining our workflows, enabling greater efficiency, stimulating innovation and allowing our dollar to go further. They include:

- **leveraging All of Government (AOG) contracts** where appropriate
- **introducing the Early Contractor Involvement model (ECI)** to collaboratively develop contractual structures for major projects
- **introducing multi-supplier, multi-year contracts** where they make sense
- **instigating supplier factory visits** to build relationships and check on quality and ethical considerations
- **introducing modern slavery clauses** in our contracts ahead the introduction of legislation
- **reforming the contracts performance framework** to incorporate additional factors such as quality
- **adopting DocuSign®** for electronic signature of contracts
- **introducing Procurement Plans** to evaluate and document our approach to market before we start
- **commencing trials of syndicated procurement** for PPE with Connetics and electronic network security in conjunction with other Christchurch City Council Holdings companies
- **introducing the Government Electronic Tendering System (GETS)** that has simplified the process for open tenders to be more visible and efficient for both Orion and those tendering
- **introducing price value scoring for tenders** which allows us to give due consideration to factors such as safety and technical innovation

We have recently implemented several significant improvements to our contracting and procurement processes.

9.6 Managing factors affecting project delivery

Orion is navigating a range of local and global challenges to deliver our 10-year Asset Management Plan. Many of these factors are sector wide and collaboration with our sector peers, service providers, educators and those innovating in the energy sector is vital to addressing these issues. So too is the need to be agile and flexible in our planning at which we have become adept.

For more detail on the impacts of price inflation on project costs, see Section 2.4.2.10.

For an overview of the key factors impacting our ability to deliver this AMP and how we are managing our response to them, see Figure 9.6.1.

Figure 9.6.1 Factors affecting project delivery

Factor	How we are managing it
Workforce shortages • Shortage of skilled trained workers • Competition from overseas and locally • Salaries surging	• Strategic focus on Orion Group as the preferred workplace • Continuing to invest in the capability of the Orion team • Working with industry and training partners to build the workforce size and capability • Changing work practices to increase efficiency and productivity
Supply chain issues • Uncertainty around equipment delivery timeframes; delays • International competition for equipment supply – we are a small player • Cost escalation	• Building in longer ordering lead-times • Increasing stock of essential items, standardising equipment • Being the “customer of choice” for service providers • Flexible planning and good budgeting • Improving our ability to estimate cost increases
Climate change • Increased growth of vegetation near lines • Higher risk of severe weather events • Increases the pace of decarbonisation	• Increased expenditure on tree trimming and encouraging responsible vegetation management around overhead lines • Replacing end-of-life poles with more resilient designs • For more detail on our climate risks and mitigation strategies, see our FY23 Climate Statement, available on our website
World decarbonisation • Increased demand for equipment supplies • Equipment shortages and increased costs • Rapidly changing technology standards	• Building closer relationships with equipment suppliers • Improving our procurement and contracting processes, see 9.5.2 • Improving our ability to estimate cost increases • Close collaboration with sector innovators • See also our FY23 Climate Statement, available on our website
Regulatory uncertainty • Regulatory rules and mechanisms may place funding constraint on investment • Local Government consenting delays	• Regular submissions and discussions with regulators • Longer lead times for consents

9.6 Managing factors affecting project delivery continued

9.6.1 Current programme completion

With a flexible approach to planning and project management, we have been able to make good progress on completion of our key – more than $100m – projects in FY24.

For a summary of the completion status of our key projects, see Table 9.6.1.

Table 9.6.1 Key projects' completion status as of March 2024

Projects	Category	Status
Heathcote ZS 11kV switchgear replacement	11kV Switchgear replacement	Completed
Hawthornden ZS 11kv Switchgear replacement	11kV switchgear replacement	Work in progress, on schedule
Norwood GXP	220kV/66kV GXP & Zone Substation	Completed
Dunsandel ZS to Norwood 66kV line	66kV Overhead line	Completed
Milton ZS 66kV switchgear and building	66kV Zone Substation	Completed
Bromley ZS to Milton ZS – 66kV cable	66kV Underground cable	Work in progress, on schedule
Burnham ZS	66kV Zone Substation	Work in progress, on schedule
Springston ZS 2nd 66/11kV transformer bank	66kV/11kV Power transformer	Work in progress, on schedule

9.7 Conclusions on our ability to deliver our forecast work programme

We are confident in our ability to deliver our forecast opex and capex programmes as detailed in this AMP, given:

- we have carefully assessed our programme delivery risks and developed a robust range of strategies to address them
- we plan our opex and capex spend over the next five to ten years – this provides certainty for our PSDP and other key service providers to continue to invest in their resource and capability to meet our needs
- being conscious of not wanting to take on more than we can deliver, we have looked critically at our work programme, and pared back expenditure in some key areas to keep costs and resourcing within our capability and to support customer affordability
- we have a partnership approach with our PSDP and other service providers and by engaging with them on our long term proposed works programme, they are able to plan ahead to resource to meet our needs

Development of the sector's workforce availability and skills will take time and a key dependency is ensuring our regulatory regime recognises our need to invest in developing this capability.

We have set ourselves an ambitious plan over the next ten years and recognise there is a range of uncertainties in the environment in which we operate. While these may impact on our capacity to deliver individual projects, the experience we have gained over many years and our skill at adapting to the rapid pace of change more recently has equipped us well to manage our programme of work in a more fluid environment. We will continue to invest in the capability and resourcing required, both internal and external, to deliver on our forward works plan.

Through proactive management of the changes in our environment, our increased skill in performing with greater flexibly and with more agility, Orion is confident we can undertake the projects we have set out in this plan that will enable us to continue to maintain and develop our network to meet our customer's needs.

10 Financial forecasting

$458m

Network operating expenditure

$630m

Non-network operating expenditure

$2.33m

Capital expenditure

Photo: Shot from Plantation Road, Hororata during a nor'wester at sunset; photo taken by Orion Network Operator, Martin Van Beyere.

Contents

10.1 Introduction

This section details our financial forecasts for capital and operational expenditure over the 10-year period of this AMP.

Our forecasts are based on our network's capital and operational expenditure programmes and projects that are set out in Sections 7 and 8. These forecasts are developed with the best available information at the time of publication and are expressed in real dollar terms as explained in Appendix F.

10.2 Network expenditure forecasts

10.2.1 Network capital expenditure

The biggest drivers for Orion's capital investment in our network are:

- **Asset replacement** – over the 10-year period of this AMP, we remain focused on the replacement of legacy assets installed during the 1960s to 1980s, to ensure our network's ongoing safety and reliability. We are also focused on increasing network resilience by targeting replacement of our poles in high wind zones. Poles in these zones are at higher risk of failure due to their design and construction not meeting the challenges posed by more harsh weather conditions because of climate change.
- **Network development** – we are investing to support the growing needs of our region, expanding network capacity and relieving network constraints to accommodate strong population growth and increased electrification.
- **Customer connections** – we are providing for ongoing strong growth in residential connections as people continue to migrate to our region, and we support commercial customers to electrify their process heat needs.

On occasion we are required to relocate some of our assets or convert sections of our overhead lines to underground cables at the request of road corridor authorities, councils or developers. This forecast is captured under 'Asset relocations'.

Table 10.2.1 Network capital expenditure summary – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Customer connections/ network extensions	24,502	25,719	25,690	26,415	26,513	27,935	29,434	31,012	32,676	34,428	**284,324**
Asset relocations	11,242	9,834	8,179	6,199	8,382	8,010	8,194	7,910	8,091	8,400	**84,441**
Network development	35,949	70,955	97,193	84,393	99,241	105,135	114,275	95,146	102,275	109,102	**913,664**
Replacement	41,500	53,281	63,601	73,038	69,022	69,903	71,228	73,069	72,983	72,921	**660,546**
Network transformation	296	3,432	7,381	4,439	3,336	3,413	3,491	3,571	3,653	3,737	**36,749**
Data and digitisation	192	177	157	162	165	169	173	177	181	185	**1,738**
Capitalised internal labour	8,546	12,291	15,214	14,807	15,757	16,399	17,388	16,286	16,971	17,652	**151,311**
Project management resource (PMO)	3,015	3,193	3,351	3,482	3,608	3,725	3,844	3,973	4,105	4,241	**36,537**
Total	**125,242**	**178,882**	**220,766**	**212,935**	**226,024**	**234,689**	**248,027**	**231,144**	**240,935**	**250,666**	**2,169,310**
Total from 1 April 2023 AMP	**130,832**	**192,328**	**251,762**	**262,111**	**307,495**	**341,137**	**383,217**	**418,808**	**448,624**	**n/a**	**n/a**

10.2 Network expenditure forecasts continued

Table 10.2.2 Network capital contributions revenue – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Customer connections / network extensions	(8,283)	(14,577)	(16,252)	(19,129)	(22,863)	(21,564)	(22,059)	(9,407)	(9,623)	(9,844)	**(153,601)**
Asset relocations	(9,984)	(8,052)	(7,159)	(5,473)	(6,397)	(7,678)	(8,194)	(7,910)	(8,031)	(8,215)	**(77,093)**
Total	**(18,267)**	**(22,629)**	**(23,411)**	**(24,602)**	**(29,260)**	**(29,242)**	**(30,253)**	**(17,317)**	**(17,654)**	**(18,059)**	**(230,694)**
Totals from 1 April 2023 AMP	**(23,330)**	**(32,266)**	**(28,882)**	**(25,551)**	**(30,881)**	**(41,683)**	**(55,557)**	**(69,397)**	**(85,885)**	**n/a**	**n/a**

Table 10.2.3 Replacement capital expenditure – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Overhead	17,172	17,950	25,793	29,741	31,452	35,065	37,626	39,508	41,456	40,841	**316,604**
Underground	8,050	9,204	8,782	2,237	2,288	2,341	2,395	2,450	2,506	1,464	**41,717**
Monitoring	92	97	101	26	26	27	28	228	475	523	**1,623**
Protection	1,230	2,572	2,376	2,588	2,442	2,619	2,715	3,897	3,141	3,138	**26,718**
Communication systems	1,547	1,194	612	1,695	2,158	1,971	1,456	1,551	1,336	1,366	**14,886**
Control systems	819	1,337	779	1,219	733	1,389	891	1,639	913	1,694	**11,413**
Load management	840	781	1,378	1,212	1,295	1,077	997	1,037	831	1,550	**10,998**
Switchgear	8,703	16,315	19,371	24,156	18,897	19,271	18,254	15,739	15,145	14,999	**170,850**
Transformers	1,451	1,916	2,417	7,639	6,820	2,600	2,660	2,721	2,784	2,848	**33,856**
Substations	754	908	944	1,986	2,583	3,206	3,857	3,945	4,036	4,129	**26,348**
Generators (fixed)	23	24	25	26	26	27	28	28	29	30	**266**
Buildings and enclosures	774	933	970	458	248	254	260	266	272	278	**4,713**
Grounds	48	50	52	54	55	56	58	59	60	62	**554**
Total	**41,503**	**53,281**	**63,600**	**73,037**	**69,023**	**69,903**	**71,225**	**73,068**	**72,984**	**72,922**	**660,546**
Totals from 1 April 2023 AMP	**45,527**	**59,526**	**79,532**	**85,006**	**91,929**	**88,663**	**93,488**	**98,096**	**95,947**	**n/a**	**n/a**

10.2 Network expenditure forecasts continued

10.2.2 Network operational expenditure

Two of our key network operational investments are focussed on:

- **Vegetation management** – we are implementing a data-driven, risk-based approach by prioritising our vegetation management programmes targeted at high-risk zones. Our aim is to minimise the number of power outages and safety incidents caused by vegetation on overhead lines, particularly during severe weather events.
- **Routine and corrective maintenance and inspection** – while maintaining a consistent level of maintenance and inspection activities, we are adjusting our expenditure over the next decade to gather more comprehensive asset condition data to guide a risk-based replacement programme for our overhead conductors. This approach will ensure we are replacing the correct conductors at the appropriate time, and aims to increase the safety and reliability of this critical asset.

Table 10.2.4 Network operational expenditure summary – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Overhead	15,365	17,731	19,236	20,199	22,922	25,846	28,766	30,649	31,926	32,865	**245,505**
Underground	4,463	4,583	4,603	4,635	4,671	4,803	4,853	4,801	4,837	4,876	**47,125**
Monitoring	35	41	19	27	43	35	43	139	83	114	**579**
Protection	586	683	684	697	707	713	720	726	732	739	**6,987**
Communication systems	683	664	616	623	629	634	639	645	650	657	**6,440**
Control systems	618	621	758	713	739	775	868	866	961	904	**7,823**
Load management	397	391	400	404	412	417	425	428	438	441	**4,153**
Switchgear	1,388	1,687	1,814	1,958	1,956	2,042	2,080	1,958	1,946	1,963	**18,792**
Transformers	1,402	1,379	2,388	2,228	1,773	1,026	1,035	1,045	1,054	1,064	**14,394**
Substations	1,223	1,248	1,218	1,232	1,247	1,258	1,270	1,281	1,292	1,304	**12,573**
Generators (fixed)	43	42	43	43	44	44	44	45	45	46	**439**
Buildings and enclosures	1,081	1,121	1,121	1,153	1,144	1,174	1,165	1,195	1,195	1,155	**11,504**
Grounds	480	542	551	567	572	577	602	607	613	638	**5,749**
Asset management system	5	5	5	5	5	5	5	5	5	5	**50**
Emergency fixed cost	2,594	2,523	2,431	2,458	2,480	2,502	2,524	2,546	2,569	2,591	**25,218**
Project management resource (PMO)	1,506	1,557	1,596	1,629	1,657	1,690	1,717	1,748	1,786	1,812	**16,698**
Data and digitisation	96	98	100	101	102	103	104	105	106	107	**1,022**
Network transformation	614	4,242	5,087	3,419	3,385	3,415	3,217	3,245	3,274	3,303	**33,201**
Total	**32,579**	**39,158**	**42,670**	**42,091**	**44,488**	**47,059**	**50,077**	**52,034**	**53,512**	**54,584**	**458,252**
Totals from 1 April 2023 AMP	**31,812**	**46,087**	**48,929**	**51,861**	**54,225**	**56,993**	**60,729**	**61,148**	**62,653**	**n/a**	**n/a**

10.2 Network expenditure forecasts continued

Table 10.2.5 Network operational contributions revenue – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
USI load management	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	**(1,000)**
Network recoveries	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	**(10,000)**
Total	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(11,000)**
Totals from 1 April 2023 AMP	**(1,099)**	**(1,098)**	**(1,097)**	**(1,096)**	**(1,095)**	**(1,094)**	**(1,093)**	**(1,092)**	**(1,091)**	**n/a**	**n/a**

10.3 Non-network expenditure forecasts

This section describes our non-network forecast to plan, operate and administer our network operations. This does not include expenditure on our network assets, consistent with the Commerce Commission's required expenditure breakdowns and definitions. The expenditure forecast is in real dollar terms as described in Appendix F and does not include pass-through costs, such as local authority rates and industry levies, depreciation and transmission purchases.

10.3.1 Non-network capital expenditure

The most significant driver of non-network capital expenditure is the implementation of the Integrated Asset Management (IAM) platform. This involves upgrading and developing systems to enhance our asset management capabilities and customer tools. Through the digitisation of asset data, we will improve our ability to leverage condition and inspection findings, and enable us to make to make well-informed, risk-based decisions about our asset investments.

The most significant driver of non-network capital expenditure is the implementation of the Integrated Asset Management (IAM) platform.

Table 10.3.1 Non-network capital expenditure – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Plant and vehicles	1,250	927	755	1,590	1,365	947	1,005	1,005	1,005	1,005	**10,854**
Technology and platform services	15,205	11,620	11,517	10,858	11,450	10,195	10,480	10,570	10,170	10,330	**112,395**
Corporate properties	255	255	255	255	255	255	255	255	255	255	**2,550**
Tools and equipment	1,023	630	705	590	590	590	590	740	590	590	**6,638**
Network transformation programmes	4,550	3,616	4,179	2,489	2,489	2,535	2,350	2,350	2,350	2,350	**29,258**
Total	**22,283**	**17,048**	**17,411**	**15,782**	**16,149**	**14,522**	**14,680**	**14,920**	**14,370**	**14,530**	**161,695**
Totals from 1 April 2023 AMP	**14,228**	**13,641**	**11,527**	**11,071**	**11,198**	**7,499**	**8,454**	**8,032**	**7,868**	**n/a**	**n/a**

10.3.2 Non-network operational expenditure

Over the 10-year period of this AMP, we expect to increase the level of system operations and network support required. We are actively engaged in assessing the future requirements for workforce size and expertise to effectively navigate the expanding scale and scope of our network. We anticipate there will be heightened demand for specialised talents in system operations and network support during the latter years of this period, including robotics and AI experts, business analysisits, power system engineers, data analysts, control system engineers, project managers and field crew. We are also committed to delivering our ongoing Network Transformation Programme which will maintain the reliability and efficiency of our network design and operations, and minimise disruptions.

We are actively engaged in assessing the future requirements for workforce size and expertise to effectively navigate the expanding scale and scope of our network.

Table 10.3.2 System operations and network support – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Infrastructure management	1,027	1,163	1,163	1,163	1,411	1,483	1,591	1,597	1,653	1,646	**13,897**
Network strategy and transformation	2,502	4,497	4,428	4,241	4,506	4,709	4,237	4,255	4,437	4,412	**42,224**
Network management	5,593	5,682	5,953	6,158	7,473	7,855	8,423	8,454	8,755	8,714	**73,060**
Network operations	7,811	8,042	8,517	8,517	10,336	10,864	11,650	11,692	12,109	12,052	**101,590**
Customer support	836	1,118	1,118	1,118	1,357	1,426	1,529	1,535	1,589	1,582	**13,208**
Engineering	4,497	4,497	4,804	4,804	5,830	6,128	6,571	6,595	6,830	6,798	**57,354**
Works delivery	1,630	1,630	1,630	1,630	1,977	2,078	2,224	2,236	2,316	2,305	**19,656**
Customer connections	2,734	2,734	2,734	2,734	3,318	3,487	3,740	3,753	3,887	3,869	**32,990**
Procurement and property services	1,275	1,275	1,275	1,275	1,547	1,626	1,744	1,750	1,813	1,804	**15,384**
Quality, health, safety and environment	1,423	1,423	1,423	1,423	1,727	1,815	1,946	1,953	2,023	2,014	**17,170**
Asset storage	1,100	1,100	1,100	1,100	1,335	1,403	1,505	1,510	1,564	1,557	**13,274**
Less capitalised internal labour	(8,894)	(12,186)	(14,509)	(13,734)	(14,287)	(14,536)	(15,067)	(13,795)	(14,053)	(14,289)	**(135,350)**
Total	**21,534**	**20,975**	**19,636**	**20,429**	**26,530**	**28,338**	**30,093**	**31,535**	**32,923**	**32,464**	**264,457**
Totals from 1 April 2023 AMP	**22,258**	**25,464**	**26,557**	**29,160**	**32,900**	**31,780**	**34,139**	**37,527**	**41,037**	**n/a**	**n/a**

Table 10.3.3 Board of directors' fees and expenses – $000

Category	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	Total
Board of directors' fees and expenses	415	437	437	437	437	437	437	437	437	437	**4,348**
Total	**415**	**437**	**437**	**437**	**437**	**437**	**437**	**437**	**437**	**437**	**4,348**
Totals from 1 April 2023 AMP	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**454**	**n/a**	**n/a**

10.3 Non-network expenditure forecasts continued

Table 10.3.4 Business support – $000											
Category	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**Total**
Future network	1,883	1,702	1,702	1,702	1,785	1,837	1,909	1,950	1,990	1,978	**18,438**
People and capability	1,481	1,507	1,607	1,385	1,452	1,494	1,553	1,587	1,619	1,610	**15,295**
Leadership	9,972	9,418	10,251	10,363	10,613	11,097	11,649	12,050	12,450	12,554	**110,417**
Finance	2,169	2,061	2,061	2,061	2,161	2,224	2,312	2,361	2,409	2,395	**22,214**
Technology and platform services	7,250	8,002	8,143	8,074	8,601	8,838	9,035	9,404	9,624	9,549	**86,520**
Commercial	2,040	2,507	2,507	2,507	2,655	2,732	2,815	2,876	2,935	2,918	**26,492**
Customer and stakeholder	2,535	2,715	2,715	2,715	2,847	2,930	3,045	3,110	3,174	3,155	**28,941**
Insurance	3,477	3,764	4,074	4,409	5,002	5,537	6,161	6,731	7,333	7,831	**54,319**
Corporate property	1,221	1,242	1,257	1,068	1,132	1,174	1,229	1,263	1,298	1,300	**12,184**
Vehicles	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	(1,405)	**(14,050)**
Total	**30,623**	**31,513**	**32,912**	**32,879**	**34,843**	**36,458**	**38,303**	**39,927**	**41,427**	**41,885**	**360,770**
Totals from 1 April 2023 AMP	**28,263**	**32,643**	**33,948**	**38,029**	**42,525**	**47,882**	**53,127**	**58,993**	**64,900**	**n/a**	**n/a**

10.4 Total expenditure forecast

Table 10.4.1 Total capital and operational expenditure forecast – $000											
Category	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**Total**
Capital expenditure	147,525	195,930	238,177	228,717	242,173	249,211	262,707	246,064	255,305	265,196	**2,331,005**
Operational expenditure	85,151	92,083	95,655	95,836	106,298	112,292	118,910	123,933	128,298	129,370	**1,087,826**
Total	**232,676**	**288,013**	**333,832**	**324,553**	**348,471**	**361,503**	**381,617**	**369,997**	**383,603**	**394,566**	**3,418,831**
Totals from 1 April 2023 AMP	**275,897**	**335,675**	**329,708**	**352,012**	**372,242**	**389,763**	**384,673**	**404,897**	**425,081**	**n/a**	**n/a**

10.5 Financial progress against forecast

In this section, we review our performance in delivering the plans set out in our 2023 AMP in terms of financial progress. We have reviewed the 2022/23 financial years for both network capital and operational programmes, and evaluated margin inclusive financial performance. Explanations are provided for work programmes with a variance of greater than 10% of budget for capital expenditure and an underspend variance of 7% for operational expenditure.

Overall, there was an over-expenditure of $10.5m. Most of this stems from projects such as the Milton 66kW switching station, which spans multiple years. Some of the budget allocated for FY23 was transferred to FY24 to ensure its completion. Delays in obtaining materials resulted in some underspending, particularly in areas such as switchgear replacement and the installation of the Springston 2nd 66/11kV transformer bank. Underspending in asset relocation was mainly due to external factors, such as changes in the work plans of developers and Waka Kotahi NZ Transport Agency.

Table 10.5.1 Network capital expenditure spend against forecast in 2023 AMP

	2023 AMP forecast ($000)	Actual spend ($000)	Variance (%)
Consumer connection	22,207	45,521	105%
System growth	14,358	5,636	-61%
Asset replacement and renewal	32,234	33,441	4%
Asset relocations	7,560	957	-87%
Reliability, safety and environment	29,703	31,023	4%
Total network capital expenditure	**106,062**	**116,578**	**10%**

Our total network maintenance spend for 2022/2023 of $28m was broadly consistent with our budget forecast of $30m. The breakdown is shown in table below.

Table 10.5.2 Network operational expenditure spend against forecast in 2023 AMP

	2023 AMP forecast ($000)	Actual spend ($000)	Variance (%)
Service interruptions and emergencies	7,493	10,680	43%
Vegetation management	5,024	4,507	-10%
Routine and corrective maintenance and inspections	15,457	12,281	-21%
Asset replacement and renewal	2,401	884	-63%
Total network operational expenditure	**30,375**	**28,352**	**-7%**

Appendices

Photo: Virtual reality creates an immersive environment, made possible by power to both render and display the content.

Contents

Appendix A Glossary of terms

A: Ampere; unit of electrical current flow, or rate of flow of electrons.

ABI: Air Break Isolator; a pole mounted isolation switch. Usually manually operated.

AC: Alternating current; a flow of electricity which reaches maximum in one direction, decreases to zero, then reverses itself and reaches maximum in the opposite direction. The cycle is repeated continuously.

ADMS: Advanced Distribution Management System; a software package to control and optimise the operation of an electrical distribution network.

Alpine Fault: a geological fault, specifically a right-lateral strike-slip fault that runs almost the entire length of New Zealand's South Island. It has an average interval for a major earthquake at every 290 years, plus or minus 23 years. The last major Alpine Fault earthquake occurred in 1717. The longest known major Alpine Fault earthquake return rate is believed to be around 350 years and the shortest around 160 years.

AMP: Asset Management Plan.

Biofuel / Biomass: Biofuels are any fuel produced from biological matter or 'biomass'. This can include agricultural and forestry crops and residues, organic by-products, and waste such as used cooking oil. Biofuels can help reduce emissions and contribute towards meeting Aotearoa New Zealand's climate targets.

Biodiesel: a renewable, biodegradable fuel manufactured from vegetable oils, animal fats, or recycled restaurant grease.

Bushing: an electrical component that insulates a high voltage conductor passing through a metal enclosure.

Capacitance: the ability of a body to store an electrical charge.

Capacity utilisation: a ratio which measures the utilisation of transformers in the network. Calculated as the maximum demand experienced on an electricity network in a year, divided by the transformer capacity on that network.

CB: Circuit breaker; a device which detects excessive power demands in a circuit and cuts off power when they occur. Nearly all of these excessive demands are caused by a fault on the network. In the urban network, where most of these CBs are, they do not attempt a reclose after a fault as line circuit breakers may do on the rural overhead network.

CBRM: Condition Based Risk Model; a modelling programme which combines asset information, observations of condition and engineering knowledge and experience to produce a measure of asset health, the CBRM Health Index. The model also produces forecasts of asset probability of failure, and a measure of asset related risk in future years which can be used for developing optimised asset renewal plans.

CCC: Christchurch City Council; the local government authority for Christchurch in New Zealand.

Continuous rating: the constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely effecting it characteristics.

Conductor: the 'wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.

CPP: Customised Price-Quality Path Determination set by the Commerce Commission for Orion and in effect from FY15 to FY19. This determination applied to Orion to cover the extraordinary period of network rebuilding during recovery from the Canterbury earthquakes.

CRM: a customer relationship management system or software that helps track information and interactions between a company and its customers, with the goal of improving relationships and outcomes.

Current: the movement of electricity through a conductor, measured in amperes (A).

Customer Demand Management: shaping the overall customer load profile to obtain maximum mutual benefit to the customer and the network operator.

DER: Distributed Energy Resources; the capacity for customers to generate and store their own energy from sources including solar and wind will see electricity fed into grids locally, from households and businesses.

DERMS: Distributed Energy Resources Management System; a software platform used to manage a group of distributed energy resources.

DIN: Deutsches Institut für Normung; the German Institute for Standardisation. Equipment manufactured to these standards is often called 'DIN Equipment'.

Distribution substation: is either a building, a kiosk, an outdoor substation or pole substation taking its supply at 11kV and distributing at 400V.

DPP: Default Price-Quality Path 2020-25; applies to electricity lines businesses that are subject to price-quality regulation and is set by the Commerce Commission. It sets the maximum allowable revenue that the businesses can collect. It also sets standards for the quality of services that each business must meet.

DSO: Distribution System Operator; an entity responsible for distributing and managing energy from the transmission grid and other generation sources to the final consumers.

EV: Electric Vehicles; a vehicle that uses electricity for propulsion.

Fault current: the current from the connected power system that flows in a short circuit caused by a fault. Feeder: a physical grouping of conductors that originate from a zone substation circuit breaker.

Flashover: a disruptive discharge around or over the surface of an insulator.

Flexibility services: are a range of existing and developing solutions that electricity system users can provide to help balance demand and supply in the electricity network and support its efficient use. Flexible technologies such as electric vehicles and solar can provide 'flexibility services' to electricity networks. By releasing power back to the grid at times of high demand, and storing it during times of lower demand, local 'flexibility services' unlock additional capacity and avoid network over-build.

Frequency: on alternating current circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)

Fuse: a device that will heat up, melt and electrically open the circuit after a period of prolonged abnormally high current flow. Gradient, voltage: the voltage drop, or electrical difference, between two given points.

GXP: Grid exit point; a point where Orion's network is connected to Transpower's transmission network.

GIDI Fund: Government Investment in Decarbonising Industry Fund. The GIDI Fund was launched in 2020 to accelerate the decarbonisation of industrial process heat – and is a partnership between Government and businesses.

Harmonics (wave form distortion): changes an AC voltage waveform from sinusoidal to complex and can be caused by network equipment and equipment owned by customers including electric motors or computer equipment.

HILP: High-Impact-Low-Probability; an event that is not likely to occur but will have significant consequence to an organisation.

HV: High voltage; voltage exceeding 1,000 volts (1kV), in Orion's case generally 11kV, 33kV or 66kV.

ICP: installation control point; a uniquely numbered point on our network where a customer(s) is connected.

Inductance: is the property of a conductor by which current flowing through it creates a voltage (electromotive force) in both the conductor itself (self-inductance) and in any nearby conductors.

Insulator: supports live conductors and is made from material which does not allow electricity to flow through it.

Interrupted N-1: a network is said to have 'Interrupted N-1' security or capability if following the failure of 'one' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

Interrupted N-2: a network is said to have 'Interrupted N-2' security or capability if following the failure of 'two' overhead line, cable or transformer the network can be switched to restore electricity supply to customers.

ISO 55000: International Standards for Asset Management.

kV: Kilovolts; 1,000 volts.

kW: Kilowatt; a unit of electric power, equal to 1000 watts.

kWh: Kilowatt hour; a unit of energy equal to one kilowatt of power sustained for one hour.

kVA: Kilovolt-ampere; an output rating which designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.

LCB: Line circuit breaker; a circuit breaker mounted on an overhead line pole which quickly cuts off power after a fault so no permanent damage is caused to any equipment. It switches power back on after a few seconds and, if the cause of the fault has gone, (e.g. a branch has blown off a line) then the power will stay on. If the offending item still exists then power will be cut again. This can happen up to three times before power will stay off until the fault is repaired. Sometimes an LCB is known as a 'recloser'.

Legacy assets: assets installed to meet appropriate standards of the time, but are not compliant with current day safety standards.

Lifelines groups: local collaborations between lifeline utilities. They aim to reduce infrastructure outages, especially if HILP events occur. It was this collaboration that lead us to invest to strengthen our key substations before the Canterbury earthquakes.

LV: Low voltage; a voltage not exceeding 1,000 volts, generally 230 or 400 volts.

Maximum demand: the maximum demand for electricity, at any one time, during the course of a year.

MW: Megawatt; a unit of electric power, equal to 1000 kilowatts.

MWh: Megawatt hour; a unit of energy equal to one Megawatt of power sustained for one hour.

N: a network is said to have 'N' security or capability if the network cannot deliver electricity after the failure of 'one' overhead line, cable or transformer.

N-1: a network is said to have 'N-1' security or capability if the network continues to deliver electricity.

N-2: a network is said to have 'N-2' security or capability if the network continues to deliver electricity after the failure of 'two' overhead lines, cables or transformers.

Network deliveries: total energy supplied to our network through Transpower's grid exit points, usually measured as energy supplied over the course of a year.

Network substations: are part of Orion's primary 11kV network all within the Christchurch urban area.

Ohm: a measure of the opposition to electrical flow, measured in ohms.

Open network framework: in an open network framework anyone can connect and use any equipment they want to buy or sell electricity services – including solar, batteries. An open network framework also enables the trading of electrical energy and capacity between consumers and market participants using the electricity distribution network.

ORDC: optimised depreciated replacement cost, prepared in accordance with New Zealand International Financial Reporting Standards (NZ IFRS) under International Accounting Standard NZ IAS 16 – Property, Plant and Equipment as at 31 March 2007.

Outage: an interruption to electricity supply. Power cut.

PCB: Polychlorinated biphenyls (PCBs) were used as dielectric fluids in transformers and capacitors, coolants, lubricants, stabilising additives in flexible PVC coatings of electrical wiring and electronic components. PCB production was banned in the 1970s due to the high toxicity of most PCB congeners and mixtures. PCBs are classified as persistent organic pollutants which bio-accumulate in animals.

PMO: Project Management Office.

Proven voltage complaint: a complaint from a customer concerning a disturbance to the voltage of their supply which has proven to be caused by the network company.

PSDP: Primary Service Delivery Partner.

PV: Photovoltaics; panels which convert light into electricity, commonly known as solar panels.

Ripple control system: a system used to control the electrical load on the network by, for example, switching domestic water heaters, or by signaling large users of a high price period. Also used to control streetlights.

RTU: Remote Terminal Unit; part of the SCADA system usually installed at the remote substation.

SAIDI: System Average Interruption Duration Index; an international index which measures the average duration of interruptions to supply that a customer experiences in a given period.

SAIFI: System Average Interruption Frequency Index; an international index which measures the average number of interruptions that a customer experiences in a given period.

SCADA: System Control and Data Acquisition.

SDC: Selwyn District Council; the territorial authority for the Selwyn District of New Zealand.

STATCOM: Static Synchronous Compensator; a power electronic device which regulates voltage by providing or absorbing reactive power.

Transformer: a device that changes voltage up to a higher voltage or down to a lower voltage.

Transpower: the state owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to grid exit points (GXPs) on distribution networks throughout the country.

Voltage: electric pressure; the force which causes current to flow through an electrical conductor. Voltage drop: is the reduction in voltage in an electrical circuit between the source and load.

Voltage regulator: an electrical device that keeps the voltage at which electricity is supplied to customers at a constant level, regardless of load fluctuations.

ZS: Zone substation; a major substation where either; voltage is transformed from 66 or 33kV to 11kV, two or more incoming 11kV.

Appendix B Cross reference table

As our AMP has been structured as a practical planning tool, it does not strictly follow the order laid out in the Electricity Distribution Information Disclosure Determination 2012. We have prepared the cross reference table below to help the reader find specific sections.

Sections as per the Electricity Distribution Information Determination 2012	Orion AMP section number	Orion AMP section name
Summary (3.1)	1	Executive summary
Background and objectives (3.2)	2	Our strategy
Purpose statement (3.3-3.5)	2.4	Orion Group purpose and strategy
	2.7	Asset Management System
	2.8	Asset Management Objectives
	Appendix G	Certificate for Year-beginning Disclosure
Stakeholder interests (3.6)	3.2	Stakeholder interests
	3.3	Customer engagement
	3.4	Community engagement
Accountabilities and responsibilities (3.7)	2.10	Asset management roles and accountabilities
	4.3	System operations and network support teams
	4.4	Business support teams
Assumptions (3.8, 3.9)	2.4.3	External drivers of network investment under the Central scenario
	2.5	Significant business assumptions
	8	Developing our network; assumptions are mentioned throughout this section
Asset management strategy and delivery (3.10-3.12)	2.7.2	Our strategic approach
	4.6	Systems overview
	4.8	Modernising asset information management
	4.9	Asset data integrity
	8	Developing our network
Asset management process (3.13-3.15)	2.9	AMP development process
	3.7	Performance against targets
	4.8	Modernising asset information management
	6.3	Asset lifecycle investment process
	7	Managing our assets
	8	Developing our network
Financial values (3.16)		Figures are in NZD (real)
Network context (4.1)	6.2	Current network overview
	7	Managing our assets

Sections as per the Electricity Distribution Information Determination 2012	Orion AMP section number	Orion AMP section name
Network configuration (4.2, 4.3)	6.2	Current network overview
	7	Managing our assets
	8.2	Network loading and forecast
Network assets by category (4.4, 4.5)	7	Managing our assets; subsections where applicable
Service levels (5-10)	3.7	Performance against targets
Network development planning (11.1-11.8)	2.4.3	External drivers of network investment under the Central scenario
	6.2.4	Embedded distributed generators
	6.4	Network development investment process
	6.5	Project prioritisation tool
	8.2	Network loading and forecast
	8.3	Current network security gaps
Network development options (11.9)	4.8	Mentions modernising asset information can extend asset data
	6.4	Network development investment process Alternative options are part of the business case
	8.4	Optioneering and proposals
Network development programme (11.10, 11.11)	8.4	Optioneering and proposals
Non-network solutions (11.12)	8.4	Optioneering and proposals
Lifecycle asset management planning (12,1-12.4)	7	Managing our assets
Non-network development (13.1-13.4)	4.6	Systems overview
	7.20	Vehicles
Risk management (14.1-14.4)	5.5	Our risk management responsibilities
	5.6	Our risk assessments and risk evaluations
	5.8	Our key risks
	5.9	Summary of our risks and mitigation strategies
Evaluation of performance (15.1-15.4)	3.7	Performance against targets
	10.4	Financial progress against forecast
	Appendix E	AMMAT
	5.10.5	RMMAT
Capability to deliver (16.1, 16.2)	2.10	Asset management roles and accountabilities
	3.7	Performance against targets
	4.3	System operations and network support
	4.4	Business support
	9	How we deliver

ID Tranche 1	Orion AMP section number	Orion AMP section name
Outage notification plan	3.3.8	Outage notification
Monitoring voltage quality	3.7.3.3	Power quality
Customer connection practices	3.3.9	Customer engagement over new connections
	3.3.6	Resolving customer complaint
New loads to have a significant impact on network	6.4	Network development investment process
	8.4	Optioneering and proposals
Innovation practices		Innovation Strategy – standalone document on Orion website
Lifecycle asset management planning provisions	6.3	Asset lifecycle investment process
	7.7	Vegetation management
Modelling approach and rationale used to inform capital expenditure for assets	6.3	Asset lifecycle investment process
Consideration of non-network solutions to inform its expenditure projections	6.4	Network development investment process
	8.4	Optioneering and proposals

Appendix C Specifications and standards (assets)

Design standards	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Network Asset Identification	NW70.00.12	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Network connection standard	NW70.00.15	✓	✓	✓	✓	✓	✓		✓		✓		✓			
Network – Extensions and Connections	NW70.10.03	✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓		
Draughting and Records	NW70.50.02	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Network design overview	NW70.50.05	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Safety in design	NW70.50.07	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Overhead line design standard	NW70.51.01	✓	✓	✓					✓							
Overhead line design manual	NW70.51.02		✓	✓												
Overhead line design – worked examples	NW70.51.03		✓													
Cable distribution design	NW70.52.01					✓	✓	✓	✓							
Distribution substation – design	NW70.53.01								✓	✓	✓		✓	✓		✓
Substation design – customer premises	NW70.53.02															✓
Remote Terminal Units (RTUs)	NW70.56.03								✓	✓			✓	✓	✓	
Protection – design	NW70.57.01								✓	✓			✓			
Subtransmission protection design	NW70.57.02												✓			
Distribution feeder and transformer protection	NW70.57.03												✓			
Design Application Guide – Network DC Systems	NW70.57.07								✓				✓		✓	
Earthing system design	NW70.59.01								✓	✓						
Guide to Land Access and Easements	NW72.15.06	✓	✓	✓	✓	✓	✓									✓
Street lighting and small connections network	NW72.22.20		✓	✓		✓	✓							✓		
Network service providers	NW73.10.15	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Technical Specifications	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Contract hazard management	NW72.20.10	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Orion stock management	NW72.20.11	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Land and Building Hazard management	NW72.20.13															■
Zone substation contingency spares	NW72.20.14								■	■						■
Overhead line work	NW72.21.01		■	■												
Overhead line re-tighten components	NW72.21.03	■	■	■												
Air break isolator maintenance – 11kV	NW72.21.04								■							
Tower painting	NW72.21.05	■														
Tower maintenance painting	NW72.21.06	■														
Thermographic survey of high voltage lines	NW72.21.10	■	■													
LV underground network inspection	NW72.21.12						■									
Vibration dampers – Installation	NW72.21.13	■														
Standard construction drawing set – Overhead	NW72.21.18	■	■	■												
Standard construction drawing set – Underground	NW72.21.20				■	■	■									
Standard Construction Drawing Set – High voltage Plant	NW72.21.21								■	■	■		■			
Detailed inspection of overhead line structures	NW72.21.28	■	■	■												
Excavation near overhead Electric line support	NW72.21.29	■	■	■												
IML-RESI Powerdrill	NW72.21.30	■	■	■												
Cable installation and maintenance	NW72.22.01				■	■	■	■								
Excavation, backfilling and restoration of surfaces	NW72.22.02				■	■	■	■								
Distribution cabinet installation	NW72.22.03						■									
Distribution box installation	NW72.22.10						■									

Technical Specifications	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Graffiti removal	NW72.22.11															✓
Installation and commissioning of IoT devices	NW72.22.22													✓	✓	
Mineral insulating oil maintenance	NW72.23.01									✓						
Transformer maintenance (distribution)	NW72.23.02										✓					
Distribution substation inspection	NW72.23.03							✓			✓					
Network substation inspection	NW72.23.04							✓			✓					
Distribution substation maintenance	NW72.23.05							✓			✓					
Network substation maintenance	NW72.23.06							✓			✓					
Zone substation maintenance	NW72.23.07								✓	✓						
Zone substation HVAC maintenance	NW72.23.11															✓
Zone substation inspection	NW72.23.13								✓	✓						
Kiosk installation	NW72.23.14															✓
Transformer installations (distribution)	NW72.23.16										✓					
Building sub – Installation of equipment	NW72.23.18					✓	✓	✓	✓		✓		✓		✓	✓
Cable testing	NW72.23.24				✓	✓	✓	✓								
Power transformer servicing	NW72.23.25									✓						
Vegetation work adjacent to overhead lines	NW72.24.01	✓	✓	✓												
Ripple equipment maintenance	NW72.26.02													✓		
Reg D – Application guide	NW72.26.06									✓			✓			
Unit protection maintenance	NW72.27.01							✓					✓			
Protection – Secondary system testing	NW72.27.02												✓			
Partial discharge tests	NW72.27.03								✓							

		Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
Technical Specifications	**Document ID**															
Testing and commissioning of secondary equipment	NW72.27.04												✓	✓	✓	
Summed 11kV feeder protection application guide	NW72.27.06								✓				✓			
Earthing – Installation	NW72.28.01		✓	✓		✓	✓									
Earthing – Testing	NW72.28.02		✓	✓		✓	✓									
Equipment Specifications	**Document ID**															
Personal protective equipment	NW21.07.03	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓		✓
Network Equipment application process	NW72.20.17	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Ring main units 11kV	NW74.22.01					✓			✓				✓	✓		
Distribution cable 11kV	NW74.23.04					✓										
Poles – softwood	NW74.23.06		✓	✓												
Poles – hardwood	NW74.23.08	✓	✓	✓												
Distribution cable LV	NW74.23.11						✓									
Conductor – overhead lines	NW74.23.17	✓	✓	✓												
Cross-arms	NW74.23.19	✓	✓	✓												
Earthing equipment and application	NW74.23.20		✓			✓	✓	✓								
Switchgear – 400V indoor	NW74.23.23								✓							
Circuit breaker – 66kV	NW74.23.25								✓							
Communication cable	NW74.23.40							✓								
Asset management reports	**Document ID**															
AMR – Protection Systems	NW70.00.22												✓			
AMR – Power transformers and regulators	NW70.00.23									✓						
AMR – Overhead lines – LV	NW70.00.25			✓												
AMR – Overhead lines – Subtransmission	NW70.00.26	✓														
AMR – Overhead lines – 11kV	NW70.00.27		✓													
AMR – Cables – Communication	NW70.00.28							✓								

Asset management reports	Document ID	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Communication cables	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Generators	Protection systems	Load management systems	Distribution management system	Network property
AMR – Cables – LV and Hardware	NW70.00.29						■									
AMR – Cables – 11kV	NW70.00.30					■										
AMR – Cables – 66kV	NW70.00.32				■											
AMR – Circuit Breakers	NW70.00.33							■								
AMR – Communication Systems	NW70.00.34												■	■	■	
AMR – Distribution Management	NW70.00.36														■	
AMR – Load Management	NW70.00.37													■		
AMR – Monitoring	NW70.00.38													■	■	
AMR – Generators	NW70.00.39											■				
AMR – Transformers – Distribution	NW70.00.40										■					
AMR – Property – Corporate	NW70.00.42															■
AMR – Property – Network	NW70.00.43															■
AMR – Steel Lattice Towers	NW70.00.51	■														
AMR – Switchgear HV and LV	NW70.00.24								■							
AMR – Cables – 33kV	NW70.00.31				■											
AMR – Substations	NW70.00.44															■
AMR – Vehicles	NW70.00.47															■

Appendix D Specification and standards (network planning)

Design standards	Document ID
Network architecture review: subtransmission	NW70.60.16
Urban 11kV network architecture review	NW70.60.06
Network design overview	NW70.50.05
Project prioritisation and deliverability process	NW70.60.14
Long term load forecasting methodology for subtransmission and zone substation	NW70.60.12

Appendix E Disclosure schedules 11-13

This section contains the Information disclosure asset management plan schedules.

Schedule	Schedule name
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 forecast interruptions and duration
13	Report on asset management maturity

Schedule 11a. Report on forecast capital expenditure

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2024 – 31 March 2034

7		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	33,012	30,228	40,450	41,612	43,697	63,108	66,874	70,872	46,311	49,580	53,086
11	System growth	25,710	31,756	37,966	78,624	70,933	77,865	88,602	94,124	101,892	117,094	119,951
12	Asset replacement and renewal	36,528	38,889	51,934	66,535	88,129	85,147	87,968	91,413	95,972	97,762	99,634
13	Asset relocations	12,772	12,581	11,250	9,542	7,385	10,187	9,934	10,369	10,216	10,661	11,292
14	Reliability, safety and environment:											
15	Quality of supply	16,711	5,680	35,274	32,629	24,396	18,566	16,610	24,322	22,330	19,172	28,387
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	10,257	11,206	13,440	10,597	1,163	360	376	392	410	428	433
18	**Total reliability, safety and environment**	26,968	16,886	48,714	43,226	25,559	18,926	16,986	24,714	22,740	19,600	28,820
19	**Expenditure on network assets**	134,990	130,340	190,314	239,539	235,703	255,233	270,364	291,492	277,131	294,697	312,783
20	**Expenditure on non-network assets**	18,086	22,283	17,969	18,682	17,250	17,974	16,468	16,955	17,546	17,201	17,581
21	**Expenditure on assets**	153,076	152,623	208,283	258,221	252,953	273,207	286,832	308,447	294,677	311,898	330,364
23	*plus* Cost of financing	-	700	700	700	700	700	700	700	700	700	700
24	*less* Value of capital contributions	17,569	19,010	24,075	25,401	27,232	33,041	33,688	35,555	20,762	21,593	22,534
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	135,507	134,313	184,908	233,520	226,421	240,866	253,844	273,592	274,615	291,005	308,530
29	Assets commissioned	121,200	149,313	184,908	233,520	226,421	240,866	253,844	273,592	274,615	291,005	308,530
32		**$000 (in constant prices)**										
33	Consumer connection	33,012	27,806	34,675	33,645	33,683	46,612	47,331	48,066	30,097	30,876	31,679
34	System growth	25,710	29,212	32,547	63,570	54,674	57,512	62,710	63,836	66,219	72,921	71,580
35	Asset replacement and renewal	36,528	35,773	44,521	53,796	67,930	62,890	62,261	61,998	62,372	60,882	59,457
36	Asset relocations	12,772	11,574	9,645	7,716	5,692	7,525	7,031	7,032	6,640	6,639	6,738
37	Reliability, safety and environment:											
38	Quality of supply	16,711	5,225	30,239	26,382	18,804	13,713	11,756	16,496	14,512	11,940	16,940
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	10,257	10,307	11,522	8,569	896	266	266	266	267	267	259
41	**Total reliability, safety and environment**	26,968	15,532	41,761	34,951	19,700	13,979	12,022	16,762	14,779	12,207	17,199
42	**Expenditure on network assets**	134,990	119,897	163,149	193,678	181,679	188,518	191,355	197,694	180,107	183,525	186,653
43	Expenditure on non-network assets	18,086	21,615	16,536	16,888	15,307	15,664	14,086	14,240	14,472	13,939	14,094
44	**Expenditure on assets**	153,076	141,512	179,685	210,566	196,986	204,182	205,441	211,934	194,579	197,464	200,747
46	**Subcomponents of expenditure on assets (where known)**											
48	Energy efficiency and demand side management, reduction of energy losses	2,206	988	1,638	2,179	1,990	2,040	1,819	1,658	1,675	1,482	2,056
49	Overhead to underground conversion	12,773	11,573	9,644	7,715	5,692	7,525	7,031	7,032	6,640	6,639	6,738
50	Research and development	161	-	816	816	-	-	-	-	-	-	-

Note: Forecast capex totals are consistent with the totals in prior sections of this AMP. However, Schedule 11a has total capex broken into the Commerce Commission disclosure categories and includes the apportionment of capitalised internal labour. The financial section (Section 9) has the amount of internal capitalised labour shown as a single line item.

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2024 – 31 March 2034

53		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
54	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	2,422	5,775	7,967	10,014	16,496	19,543	22,806	16,214	18,704	21,407
57	System growth	-	2,544	5,419	15,054	16,259	20,353	25,892	30,288	35,673	44,173	48,371
58	Asset replacement and renewal	-	3,116	7,413	12,739	20,199	22,257	25,707	29,415	33,600	36,880	40,177
59	Asset relocations	-	1,007	1,605	1,826	1,693	2,662	2,903	3,337	3,576	4,022	4,554
60	Reliability, safety and environment:											
61	Quality of supply	-	455	5,035	6,247	5,592	4,853	4,854	7,826	7,818	7,232	11,447
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	899	1,918	2,028	267	94	110	126	143	161	174
64	**Total reliability, safety and environment**	-	1,354	6,953	8,275	5,859	4,947	4,964	7,952	7,961	7,393	11,621
65	**Expenditure on network assets**	-	10,443	27,165	45,861	54,024	66,715	79,009	93,798	97,024	111,172	126,130
66	Expenditure on non-network assets	-	668	1,433	1,794	1,943	2,310	2,382	2,715	3,074	3,262	3,487
67	**Expenditure on assets**	-	11,111	28,598	47,655	55,967	69,025	81,391	96,513	100,098	114,434	129,617
74	**11a(ii): Consumer Connection**											
75	*Consumer types defined by EDB (see note)*	**$000 (in constant prices)**										
76	General Connections	9,676	12,675	15,020	14,512	14,527	16,554					
77	Large Customers	10,434	4,745	9,269	9,241	9,256	19,168					
78	Subdivisions	4,838	4,451	4,451	3,957	3,960	3,960					
79	Switchgear	2,688	1,978	1,978	1,978	1,980	2,475					
80	Transformers	5,376	3,957	3,957	3,957	3,960	4,455					
82	**Consumer connection expenditure**	33,012	27,806	34,675	33,645	33,683	46,612					
83	*less* Capital contributions funding consumer connections	6,985	7,929	13,295	14,258	16,321	19,069					
84	**Consumer connection less capital contributions**	26,027	19,877	21,380	19,387	17,362	27,543					
85	**11a(iii): System Growth**											
86	Subtransmission	5,279	6,274	3,730	11,217	9,477	10,480					
87	Zone substations	9,735	12,652	11,000	26,660	21,161	9,951					
88	Distribution and LV lines	1,107	1,804	2,854	4,356	2,815	7,790					
89	Distribution and LV cables	9,374	6,063	11,596	14,737	15,074	22,567					
90	Distribution substations and transformers	-	2,116	1,143	1,829	2,734	3,964					
91	Distribution switchgear	-	211	772	48	-	-					
92	Other network assets	215	92	1,452	4,723	3,413	2,760					
93	**System growth expenditure**	25,710	29,212	32,547	63,570	54,674	57,512					
94	*less* Capital contributions funding system growth	-	-	-	-	-	-					
95	**System growth less capital contributions**	25,710	29,212	32,547	63,570	54,674	57,512					

Note: Our capex budgets for new connections are broken down into asset types rather than consumer types and therefore the consumer type definitions in this schedule differ from Schedule 12c(i).

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2024 – 31 March 2034

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
98	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
99	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
100	Subtransmission	1,281	1,940	1,698	2,161	4,009	3,896
101	Zone substations	6,333	5,224	10,336	10,968	17,877	10,994
102	Distribution and LV lines	13,300	15,773	15,285	21,908	23,347	24,388
103	Distribution and LV cables	838	879	1,413	2,012	2,016	2,014
104	Distribution substations and transformers	2,608	2,227	2,749	3,145	4,911	5,413
105	Distribution switchgear	7,684	6,699	10,382	11,939	12,775	12,782
106	Other network assets	4,484	3,031	2,658	1,663	2,995	3,403
107	**Asset replacement and renewal expenditure**	36,528	35,773	44,521	53,796	67,930	62,890
108	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
109	**Asset replacement and renewal less capital contributions**	36,528	35,773	44,521	53,796	67,930	62,890
113	**11a(v): Asset Relocations**						
114	*Project or programme*	**$000 (in constant prices)**					
115	NZTA	3,849	4,847	4,946	1,978	1,980	1,980
116	Christchurch City Council	5,741	4,402	2,720	2,028	2,029	3,614
117	Selwyn Disrtict Council	1,032	1,830	1,484	3,215	1,188	1,436
118	Developer / 3rd party	2,150	495	495	495	495	495
119		-	-	-	-	-	-
121	All other projects or programmes – asset relocations						
122	**Asset relocations expenditure**	12,772	11,574	9,645	7,716	5,692	7,525
123	*less* Capital contributions funding asset relocations	10,584	9,558	7,343	6,280	4,669	5,335
124	**Asset relocations less capital contributions**	2,188	2,016	2,302	1,436	1,023	2,190
128	**11a(vi): Quality of Supply**						
129	*Project or programme*	**$000 (in constant prices)**					
130	Comms associated with line switches	66	133	305	87	87	87
131	Region A 66kV subtransmission resilience	16,645	5,092	22,555	16,854	9,334	13,299
132	Northern Christchurch security of supply	-	-	6,618	8,353	9,056	-
133	Battery Trials	-	-	435	544	-	-
134	Create / improve LV Network Model (Ops)	-	-	326	544	327	327
136	All other projects or programmes – quality of supply						
137	**Quality of supply expenditure**	16,711	5,225	30,239	26,382	18,804	13,713
138	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
139	**Quality of supply less capital contributions**	16,711	5,225	30,239	26,382	18,804	13,713
140							

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2024 – 31 March 2034

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
141							
142	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
143	**11a(vii): Legislative and Regulatory**						
144	*Project or programme*	**$000 (in constant prices)**					
145	N/A						
146							
147							
148							
150							
151	All other projects or programmes – legislative and regulatory						
152	**Legislative and regulatory expenditure**	-	-	-	-	-	-
153	*less* Capital contributions funding legislative and regulatory						
154	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
157	**11a(viii): Other Reliability, Safety and Environment**						
158	*Project or programme*	**$000 (in constant prices)**					
159	Substation security upgrade (cardax)	354	512	709	706	202	-
160	LV ties replacement with Krone	244	223	221	220	220	220
161	Supply Fuse Relocation Programme	8,226	7,625	7,748	6,353	-	-
	LV monitoring	1,433	1,550	1,531	-	-	-
	OT Review	-	305	428	428	428	-
162	Trialling of resilience options	-	-	816	816	-	-
163	Remote Sensing Assets (Drones etc)	-	92	69	46	46	46
165	All other projects or programmes – reliability, safety and environment						
166	**Other reliability, safety and environment expenditure**	10,257	10,307	11,522	8,569	896	266
167	*less* Capital contributions funding reliability, safety and environment						
168	**Other reliability, safety and environment less capital contributions**	10,257	10,307	11,522	8,569	896	266
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme*	**$000 (in constant prices)**					
175	Plant and vehicles	1,129	1,213	899	732	1,542	1,324
176	Information technology	14,926	14,749	11,271	11,171	10,532	11,107
177	Corporate properties	640	247	247	247	247	247
178	Tools and equipment	1,391	992	611	684	572	572
180		-	-	-	-	-	-
181	All other projects or programmes – routine expenditure	-	4,414	3,508	4,054	2,414	2,414
182	**Routine expenditure**	18,086	21,615	16,536	16,888	15,307	15,664
183	**Atypical expenditure**						
184	*Project or programme*						
185	N/A						
186							
187							
188							
190							
191	All other projects – atypical expenditure						
192	**Atypical expenditure**	-	-	-	-	-	-
194	**Expenditure on non-network assets**	18,086	21,615	16,536	16,888	15,307	15,664

Schedule 11b. Report on forecast operational expenditure

Company name: Orion New Zealand Ltd – AMP planning period: 1 April 2024 – 31 March 2034

7		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	9,634	9,856	9,793	9,602	10,174	10,457	10,743	11,034	11,932	12,276	12,633
11	Vegetation management	4,455	4,933	5,661	6,386	7,477	10,599	12,660	14,191	15,806	16,204	16,618
12	Routine and corrective maintenance and inspection	14,316	16,032	22,353	25,191	24,801	25,489	27,621	30,353	31,281	33,506	35,294
13	Asset replacement and renewal	381	3,085	3,853	5,119	4,139	3,693	3,189	3,276	3,368	3,465	3,566
14	**Network Opex**	28,786	33,906	41,660	46,298	46,591	50,238	54,213	58,854	62,387	65,451	68,111
15	System operations and network support	20,683	21,534	21,424	20,465	21,727	28,742	31,358	33,893	36,187	38,495	38,734
16	Business support	28,716	31,038	32,608	34,739	35,408	37,332	39,926	42,756	45,466	48,105	49,648
18	**Non-network opex**	49,399	52,572	54,032	55,204	57,135	66,074	71,284	76,649	81,653	86,600	88,382
19	**Operational expenditure**	78,185	86,478	95,692	101,502	103,726	116,312	125,497	135,503	144,040	152,051	156,493
22		**$000 (in constant prices)**										
23	Service interruptions and emergencies	9,634	9,310	8,840	8,357	8,584	8,573	8,558	8,540	8,973	8,969	8,969
24	Vegetation management	4,455	4,691	5,177	5,662	6,455	8,920	10,389	11,354	12,331	12,326	12,324
25	Routine and corrective maintenance and inspection	14,316	15,145	20,177	21,925	20,926	20,897	22,002	23,492	23,523	24,482	25,057
26	Asset replacement and renewal	381	2,914	3,478	4,455	3,493	3,027	2,540	2,535	2,533	2,532	2,532
27	**Network opex**	28,786	32,060	37,672	40,399	39,458	41,417	43,489	45,921	47,360	48,309	48,882
28	System operations and network support	20,683	20,887	20,345	19,046	19,816	25,949	27,767	29,561	30,966	32,362	31,910
29	Business support	28,716	30,119	31,005	32,361	32,330	34,235	35,801	37,590	39,165	40,620	41,065
31	**Non-network opex**	49,399	51,006	51,350	51,407	52,146	60,184	63,568	67,151	70,131	72,982	72,975
32	**Operational expenditure**	78,185	83,066	89,022	91,806	91,604	101,601	107,057	113,072	117,491	121,291	121,857
33	**Subcomponents of operational expenditure (where known)**											
36	Energy efficiency and demand side management, reduction of energy losses	705	504	799	801	800	804	804	807	807	812	812
37	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
38	Research and development	1,070	1,427	2,306	2,556	1,652	1,327	1,327	1,327	1,327	1,327	1,327
39	Insurance	3,133	3,373	3,651	3,952	4,277	4,627	5,005	5,414	5,855	6,331	6,845
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
45	**Difference between nominal and real forecasts**	**$000**										
46	Service interruptions and emergencies	-	546	953	1,245	1,590	1,884	2,185	2,494	2,959	3,307	3,664
47	Vegetation management	-	242	484	724	1,022	1,679	2,271	2,837	3,475	3,878	4,294
48	Routine and corrective maintenance and inspection	-	887	2,176	3,266	3,875	4,592	5,619	6,861	7,758	9,024	10,237
49	Asset replacement and renewal	-	171	375	664	646	666	649	741	835	933	1,034
50	**Network Opex**	-	1,846	3,988	5,899	7,133	8,821	10,724	12,933	15,027	17,142	19,229
51	System operations and network support	-	647	1,079	1,419	1,911	2,793	3,591	4,332	5,221	6,133	6,824
52	Business support	-	919	1,603	2,378	3,078	3,097	4,125	5,166	6,301	7,485	8,583
54	**Non-network opex**	-	1,566	2,682	3,797	4,989	5,890	7,716	9,498	11,522	13,618	15,407
55	**Operational expenditure**	-	3,412	6,670	9,696	12,122	14,711	18,440	22,431	26,549	30,760	34,636

Schedule 12a Report on asset condition

					Asset condition at start of planning period (percentage of units by grade)							
7												
8					H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
9	Voltage	Asset category	Asset class	Units								
10	All	Overhead Line	Concrete poles / steel structure	No.	0.01%	-	0.12%	12.60%	87.27%	-	3	1.25%
11	All	Overhead Line	Wood poles	No.	0.26%	-	1.92%	12.04%	85.78%	-	3	9.77%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	13.78%	48.87%	37.35%	-	3	1.64%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	41.46%	57.98%	0.56%	-	2	13.14%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-	-	2	-
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.	-	7.32%	36.59%	35.37%	20.73%	-	3	6.10%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	14.81%	70.37%	11.11%	3.70%	-	3	77.80%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	57.41%	11.11%	31.48%	-	3	79.63%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	7.69%	1.71%	90.60%	-	3	6.84%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	27.05%	3.60%	69.35%	-	3	18.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	

Schedule 12a Report on asset condition continued

Line	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	11.76%	48.24%	40.00%	-	3	3.50%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	8.58%	38.34%	53.08%	-	2	7.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	-	14.43%	25.63%	59.94%	-	2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0.28%	1.69%	98.03%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	28.67%	46.79%	23.83%	0.72%	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sec	No.	-	-	-	26.19%	73.81%	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	53.22%	7.87%	38.91%	-	3	25.61%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	2.31%	8.78%	60.28%	28.63%	-	3	6.60%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) – except RMU	No.	-	-	-	-	-	-	N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	14.40%	21.71%	62.99%	0.90%	3	7.78%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.05%	0.84%	13.42%	23.10%	62.60%	-	3	3.95%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	20.00%	22.00%	58.00%	-	3	4.69%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	73.33%	26.67%	-	-	3	13.33%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.20%	0.66%	18.16%	41.95%	39.03%	-	3	3.54%
55	LV	LV Line	LV OH Conductor	km	-	0.30%	15.30%	56.39%	27.77%	0.23%	2	-
56	LV	LV Cable	LV UG Cable	km	-	-	0.39%	17.86%	81.75%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	1	-
58	LV	Connections	OH/UG consumer service connections	No.			5.00%	85.00%	10.00%		1	2.50%
59	All	Protection	Protection relays (electromechanical, solid state)	No.	-	-	23.55%	22.74%	53.64%	0.07%	3	16.94%
60	All	SCADA and communications	SCADA and comms equipment operating as a single system	Lot	7.19%	2.77%	13.85%	43.45%	32.74%	-	2	55.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	-	2	-
62	All	Load Control	Centralised plant	Lot	-	9.52%	66.67%	16.67%	7.14%	-	3	60.00%
63	All	Load Control	Relays	No.						100.00%	1	-
64	All	Civils	Cable Tunnels	km								

Schedule 12b Report on forecast capacity

7	**12b(i): System Growth – Zone Substations**									
8	*Existing Zone Substations*	**Current Peak Load (MVA)**	**Installed Firm Capacity (MVA)**	**Security of Supply Classification (type)**	**Transfer Capacity (MVA)**	**Utilisation of Installed Firm Capacity %**	**Installed Firm Capacity +5 years (MVA)**	**Utilisation of Installed Firm Capacity + 5yrs %**	**Installed Firm Capacity Constraint +5 years (cause)**	**Explanation**
9	Addington #1	19	30	N-1	19	63%	30	70%	No constraint within +5 years	
10	Addington #2	21	30	N-1	21	70%	40	63%	No constraint within +5 years	Transformer replacement in FY29
11	Annat	4	-	N	3	-	-	-	No constraint within +5 years	
12	Armagh	20	40	N-1	20	50%	40	60%	No constraint within +5 years	
13	Bankside	4	-	N	3	-	10	40%	No constraint within +5 years	
14	Barnett Park	10	15	N	10	64%	15	67%	No constraint within +5 years	
15	Belfast	8	15	N	8	54%	40	23%	No constraint within +5 years	N-1 provided to Belfast zone substation in FY28
16	Bromley	38	47	N-1	38	81%	47	87%	No constraint within +5 years	
17	Brookside	8	10	N	6	80%	10	80%	No constraint within +5 years	
18	Dallington	28	40	N-1	28	70%	40	70%	No constraint within +5 years	
19	Darfield	6	9	N	6	68%	9	91%	No constraint within +5 years	
20	Diamond Harbour	3	8	N	3	40%	8	40%	No constraint within +5 years	
21	Dunsandel	17	23	N-1	17	74%	23	135%	Transformer	Install 3rd transformer when needed
22	Duvauchelle	5	8	N-1	5	67%	8	53%	No constraint within +5 years	
23	Fendalton	36	40	N-1	36	90%	40	93%	No constraint within +5 years	
24	Greendale	6	10	N	6	60%	10	70%	No constraint within +5 years	
25	Halswell	19	23	N-1	19	83%	46	54%	No constraint within +5 years	Install 3rd transformer in FY27
26	Hawthornden	32	40	N-1	32	80%	40	88%	No constraint within +5 years	
27	Heathcote	27	40	N-1	27	68%	40	73%	No constraint within +5 years	
	Highfield	7	10	N	7	70%	10	80%	No constraint within +5 years	
	Hills Rd	7	10	N	7	70%	10	70%	No constraint within +5 years	
	Hoon Hay	30	40	N-1	30	75%	40	83%	No constraint within +5 years	
	Hornby	14	20	N-1	14	70%	20	85%	No constraint within +5 years	
	Hororata	8	10	N	8	80%	10	80%	No constraint within +5 years	
	Ilam	8	11	N-1	8	73%	11	73%	No constraint within +5 years	
	Killinchy	9	10	N	9	90%	10	90%	No constraint within +5 years	
	Kimberley	14	23	N-1	14	61%	23	65%	No constraint within +5 years	
	Lancaster	23	40	N-1	23	58%	40	75%	No constraint within +5 years	
	Larcomb	21	23	N-1	21	91%	23	100%	Transformer	Shift load to new Burnham zone substation as required
	Lincoln	11	11	N-1	11	100%	11	109%	Transformer	Constraint to be resolved by transfers to Springston zone substation and/or non-network alterative
	Little River	1	3	N	1	40%	3	40%	No constraint within +5 years	
	Mcfaddens	36	40	N-1	36	90%	40	93%	No constraint within +5 years	
	Middleton	28	40	N-1	28	70%	40	95%	No constraint within +5 years	

Schedule 12b Report on forecast capacity continued

12b(i): System Growth – Zone Substations

	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
	Milton	37	40	N-1	37	93%	40	103%	Transformer	Load transfer to Addington when needed
	Moffett St	17	23	N-1	17	74%	23	78%	No constraint within +5 years	
	Motukarara	3	8	N-1	3	40%	8	40%	No constraint within +5 years	
	Oxford-Tuam	20	40	N-1	20	50%	40	48%	No constraint within +5 years	
	Papanui	44	48	N-1	44	92%	48	81%	No constraint within +5 years	
	Prebbleton	8	15	N	8	53%	23	39%	No constraint within +5 years	Install 2nd transformer in FY28
	Rawhiti	31	40	N-1	31	78%	40	75%	No constraint within +5 years	
	Rolleston	12	10	N	12	120%	10	130%	Transformer	To be replaced by new Burnham zone substation
	Shands Rd	16	20	N	16	80%	20	75%	No constraint within +5 years	
	Sockburn	25	39	N	25	64%	39	69%	No constraint within +5 years	
	Springston	9	13	N	9	69%	23	39%	No constraint within +5 years	Upgrade transformer in FY25
	Te Pirita	8	10	N	8	80%	10	90%	No constraint within +5 years	
	Waimakariri	21	40	N	21	53%	40	53%	No constraint within +5 years	
28	Weedons	15	23	N	15	65%	23	87%	No constraint within +5 years	

Schedule 12c Report on forecast network demand

7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*	**Number of connections**					
9		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
11	*Consumer types defined by EDB**						
12	Streetlighting	-	15	15	15	15	15
13	General	6,271	6,367	6,500	6,640	6,780	6,920
14	Irrigation	3	5	5	5	5	5
15	Major Customer	6	20	20	20	20	20
16	Large Capacity	-	3	-	-	-	-
17	**Connections total**	6,280	6,410	6,540	6,680	6,820	6,960
18							
22	**Distributed generation**						
23	Number of connections made in year	1,533	1,307	2,000	2,000	2,000	2,000
24	Capacity of distributed generation installed in year (MVA)	11	162	64	14	14	34
25	**12c(ii) System Demand**						
26							
27	**Maximum coincident system demand (MW)**						
28	GXP demand	701	689	699	718	732	758
29	*plus* Distributed generation output at HV and above	2	2	2	2	2	2
30	**Maximum coincident system demand**	703	691	701	720	734	760
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	703	691	701	720	734	760
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	3,543	3,586	3,629	3,672	3,716	3,761
35	*less* Electricity exports to GXPs	-	-	-	-	-	-
36	*plus* Electricity supplied from distributed generation	20	20	21	21	22	23
37	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38	**Electricity entering system for supply to ICPs**	3,563	3,606	3,650	3,693	3,738	3,784
39	*less* Total energy delivered to ICPs	3,418	3,459	3,500	3,542	3,585	3,628
40	**Losses**	145	147	150	151	154	156
41							
42	**Load factor**	58%	60%	59%	59%	58%	57%
43	**Loss ratio**	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%

Schedule 12d Report forecast interruptions and duration

8		*Current year*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	For year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
10	**SAIDI**						
11	Class B (planned interruptions on the network)	13.2	13.2	17.1	17.1	17.1	17.1
12	Class C (unplanned interruptions on the network)	66.5	66.5	63.1	63.1	63.1	63.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.06	0.06	0.06	0.06
15	Class C (unplanned interruptions on the network)	0.84	0.84	0.80	0.80	0.80	0.80

Schedule 13 Report on asset management maturity

Schedule 13 is laid out with the questions and Orion's maturity level (Score) results on left hand page with the questions repeated on the facing page along with the detailed maturity level assessment criteria.
See Section 2.9 for information regarding the assessment process.

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3.5	2022 – The AM Policy document clearly reflects the drivers of Orion NZ's two main stakeholders (both local councils), in that they are their to serve the needs of their communities. The Asset Management Policy is embedded into the AMP 2022 in section 2.7. It is clear, concise and brief. It sets the asset management direction for Orion and is easy for people to understand the key aims. 2023 – Major changes to the AM policy section. Now in section 2.13 and contains AM Objectives chart. Objectives well presented – clearer than in 2022 AMP. Some objectives have been combined, merged, removed.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3.5	2022 – The Orion NZ Asset Management Strategy is imbedded within the AMP 2022 document in section 2.8.. Orion's Asset Management Strategy has five stated focus areas: 1. Re-imaging the Future Network 2. Customer Inspired 3. Powering the Low Carbon Economy 4. Accelerating Capacity 5. Lead and Grow 2023 – Now in section 2.5. Major changes. Strategies aligned with the investment drivers and Orion group strategy focus areas.	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.	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 a
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3.38	2022 – For each of these focus areas, a detailed explanation is provided within section 2.8 of AMP 2019. Each focus area topic has the following specific details documented: • Purpose; • Focus area objectives, and; • Initiatives; 2023 – They are in the AMP – section 2.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.

Schedule 13 Report on asset management maturity continued

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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3.63	2022 – The 2022 AMP sets out Orion's asset management policy, strategy, practices and expenditure forecasts for the next 10 years from 1 April 2022. This current 337 page 2022 AMP document is of a continued very high quality. Orion are planning a rewrite of the 2023 AMP document, with intentions to reduce the number of pages in the next document, if possible. 2023 – AMP has been rewritten with improved layout/readability but appears to have increased in page count.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3.5	2022 – The current 2022 AMP which covers the Orion NZ updated strategy, practices, programme of work and expenditure forecasts for the next 10 years from 1 April 2021 to 31 March 2031. The last AMP is available throughout the organisation and via their online intranet site. 2023 – Available through same avenues as before. Updated in 2023 to improve relevance in the current climate.	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?	3.5	2022 – Responsibility for AMP actions and focus is now included in in staff Job Descriptions and Contractors scopes of work. Ongoing training and awareness of the drivers within the latest AMP's continues. 2023 – No material change from 2022. 'Accountabilities and responsibilities' section portrays asset mgmt structure.	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)	3.5	2022 – The 2022 AMP is focused on upcoming and future asset improvement areas. The Orion business organisational structure has changes and the next AMP needs to align more closely with this changed focus and asset delivery outcomes. WSP saw good evidence of the planned changes and the resources now aligned to deliver these changes. 2023 – Along with rewriting the AMP, a lot of thought has gone into alignment with the altered focus. Implementation can still be affected by resource constraints and cost inflation which are both key risks and challenges. Relative to other EDB's, Orion are doing well to address these.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.75	2022 – Orion are continuing to develop and improve their contingency planning and resilience capabilities. During the recent periods of the COVID-19 restrictions, Orion have managed their response to this ongoing situation effectively. No significant loss of delivery performance has been seen. Many of the operational teams are split in two and backup control room infrastructure continues to be utilised to ensure operational resilience. 2023 – Orion's emergency response plans/procedures remain industry leading. Climate change emergency has now been identified under risk mgmt.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3.75	2022 – Orion has recently undertaken a significant organisational structure change, which has a focus on improving their asset information utilisation and a future networks focus. The new Orion Group structure consists of the following key roles, all have some degree of asset related focus: * Chief Executive * GM Future Networks * GM Electricity Networks * GM Purpose and Performance * GM Value Optimisation * GM Energy Networks * GM Growth and Development * GM Data and Digital. 2023 – The revised mgmt structure appears to be effective in addressing the future ready/digitisation shift in the industry.	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?	3.75	2022 – The current new structure has increase the amount of asset focused resource and significantly improved the resources available for asset information improvement initiatives. 2023 – Orion strives to do more work with less people by improving the efficiencies of systems and processes by utilising technology and digitisation. Expect to see evidence of progress in 2024. "We are accelerating our human capability by implementing a new performance management programme, EmPowered, to drive performance, engagement, and capability development. We have also established new roles and brought on board people with different skills and expertise to assist us to develop new ways to support our customers and community."	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?	3.75	2022 – Over the past few years it is noted that more members of the Orion Senior Leadership Team (SLT) have increased their awareness and activity in asset management improvement and awareness activities. New members of the SLT appear to be very asset focused and are providing a fresh new approach, in many cases. This combined leadership approach to asset management across the organisation is proving a very effective tool to ensuring an “Asset Management Culture” is imbedded across the organisation, not just within the infrastructure group. 2023 – The positive effects of the altered SLT structure are beginning to show throughout the business. Orion's SLT continue to be asset focussed and striving towards a high standard of asset mgmt practices.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	4	2022 – Orion are continuing the improvement process with outsourcing and procurement of asset management processes. We believe that the contractors utilised are a good fit for the goals that Orion is striving to achieve. The implementation of a new initiative to establish a Project Management Office (PMO), consisting of a combination of Orion (Network Infrastructure) and Connectics Network Service Delivery), is well underway. This is a "work in progress" and will be review next year when it should have been completed and it's performance can be assessed. The PMO is expected to streamline many asset related activities and provide an improved focused on network asset services delivery and performance outcomes. 2023 – The PMO has been established and has largely had positive effects on network delivery. Advance workload/resource forecasting still requires further refining to enable SP's to prepare for future workload.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3.75	2022 – Orion is assisting core contractor organisations to develop entry level staff in roles aligned with Orion's asset management improvement initiatives. During our discussion with Orion, WSP were given a presentation on new training initiatives which Orion and Connectics are developing together. Another Training Academy presentation was delivered to WSP. It is hoped that this new training initiative will continue to lead to other EDB's and generators joining in and developing this industry specific training programmes. Internal Orion core asset competency training is continuing to be successfully implemented and appears to be well resourced and delivered. 2023 – The Energy Academy initiative is becoming ingrained in wider industry training and competence development programmes. Through wider industry outreach, Orion are helping the wider electricity sector fulfil the skills gaps.	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?	4	2022 – Staff training programs were again discussed. Key competencies are documented in job profiles and assessed during annual performance reviews, where any training requirements are identified, and training plans developed. Competency recording is well managed, with information housed in Orion's PowerOn application, while competency management processes are carefully documented. Staff and contractors are unable to receive work management permits if their required competencies are not up to date within PowerOn. 2023 – Above still applies. Orion also supports wider industry competency initiatives .e.g. Energy Academy, Ara trades, PEET. Addressing the risk of key skills and competencies being lost with increasing retirements remaining a challenge.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/ or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities – including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	4	2022 – Staff training programs were again discussed. Key competencies are documented in job profiles and assessed during annual performance reviews, where any training requirements are identified, and training plans developed. Competency recording is well managed, with information housed in Orion's PowerOn application, while competency management processes are carefully documented. 2023 – A review of the Orion's Network Competency Training program as well as engagement with various external training providers was carried out. The results demonstrate Orion are actively monitoring and improving their training programs. Focus has moved across the training programs with some receiving greater emphasis to fill gaps (such as long term staff retention and new staff intakes) which is understandable. Further staff competancy review under NZS 7901 review.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3.38	2022 – Internal and external communications initiatives have been seen to be effective and well delivered. The high praise received from community feedback mechanisms is showing this performance very well. 2023 – Residential Consumer Survey results are very similar to last year. NPS dropped one point. Website does not display AM policy statement nor asset performance data (except in Network quality report 2018). In response to last years audit, the community engagement team has directed their focus on: • Building awareness of Orion with our customers and community. • Demonstrating that Orion is preparing for a very different future for electricity.	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?	3.5	2022 – Orion have made significant improvements and updates to many of their asset related document e.g. Asset Management Reports, on various asset topic were updated in the past two years. 2023 – AMP has been revamped for 2023. Other updated corporate publications include SOI, Annual report, climate statement.	2022 – Orion have made significant improvements and updates to many of their asset related document e.g. Asset Management Reports, on various asset topic were updated in the past two years. 2023 – AMP has been revamped for 2023. Other updated corporate publications include SOI, Annual report, climate statement.	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities – internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3.38	2022 – The AMP details the broad range of information and applications in place to support Orion's asset management system. Most basic asset management information, data and systems appear to be appropriate for the asset management requirements of the business. Orion have in the past, chosen "best of breed" (as opposed to an integrated system). They are now moving to a more integrated approach to the asset information portfolio, with dedicated new resources now tasked with this improvement delivery. Considerable improvement in this area is underway and will be reviewed next year. 2023 – Orion has produced a replacement plan for their network information systems which includes implementation of an Integrated Asset Management platform. Going to market in about 4 weeks. The migration process is a considerable time and financial investment and it is important that it is managed appropriately. Asset data integrity has been given greater focus as it is a key consideration when migrating to a new asset information system. Progress on this journey will be reviewed next year.	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?	3.63	2022 – Orion's aim is to seamlessly gather, store and package specifically requested field asset information in their Asset Register from various asset and maintenance inspections. Existing applications have been upgraded and new functionality introduced. New asset related applications are now being assessed and trailed. Next year should see many improvements in this area. 2023 – Asset Data Readiness project is underway: It is producing three deliverables: 1) Hierarchy data for model, 2) complete data model for migration and 3) an audit, gap analysis and treatment options for an asset information data cleanse workstream. Other improvements in this area include; creation of a Network Connectivity model for network analysis with a QA routine. Leveraging drones for asset information and location capture.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3.63	2022 – The AMP records the types of asset data held for each asset class. Updated data generally comes from routine compliance inspections listed in the asset maintenance plans as well as specific inspections carried out as required for a particular asset class. More remote access asset data recording is being put in place for staff and contractors. 2023 – Orion are planning migration to an Integrated asset management platform to automate asset lifecycle management. Internal auditing, gap analysis, data cleansing and QA routines all help in continual improvement of asset data capture, quality and accuracy.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
69	Risk management process(es)	How has the organisation documented process(es) and/ or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	2022 – Orion use Condition Based Reliability Management (CBRM) models for the majority of their network assets. These models utilise asset information, engineering knowledge and experience to define, justify and target asset renewal. They provide a proven and industry accepted means of prioritising risk and health to determine optimal level of capex renewals. This CBRM model is now well imbedded and continues to gain improvements. The CBRM model is one of the tools used to inform the Orion decision making for asset replacement. 2023 – No significant changes from last year. It will be interesting to see how the proposed new Integrated AM framework improves asset risk assessment.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/ or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/ or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3.13	2022 – Orion is now developing processes and applications to improve workflow processes to ensure consistency across the business. Asset focused information systems are now improved and more dedicated resources assigned to the technical/asset related information systems. separate from the business IT system and resources. 2023 – A new project prioritisation tool will help develop a portfolio of projects most aligned with Orion's Strategy and AM objectives. It will capture high level risks and resource requirements.	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?	3.63	2022 – Orion NZ continues to set high standards in this area and has a Compliance Manual which outlines the company's legal compliance obligations. 2023 – Evidence of recent updates to the statutory compliance manual was provided. Staff engagement in this space has been a focus this year.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3.75	2022 – Orion has continued to update their comprehensive suite of standards and specifications for all critical assets, covering all aspects of the asset lifecycle, from engineering through to procurement to ensure consistency in sourcing both equipment and field servicing. The process of contracting out the works programme is well documented. New processes for the PMO are in development. There are design processes and standards for the majority of the work required at the power distribution level. The activities around the creation, acquisition or enhancement of major asset classes are detailed in 22 Asset Management Reports (AMR) 2023 – Many improvements have been implemented in the PMO. Including a more collaborative contract model, early engagement, enhanced reporting. A raft of further improvements are underway, such as the Works Management replacement. We expect to see positive influence on metrics next year.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.75	2022 – Orion are continuing to update their technical specification in line with modern developments and industry best practice experiences. They have a focus to standardise equipment where possible and to phase out equipment with know issues or risks. Key applications have recently been upgraded and new functionality implemented as required. 2023 – Orion continue to keep their standards and procedures up-to-date. This year has seen a lot of updates to Procurement strategies. 34 Standards have been amended in the last 12 months.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.75	2022 – Project works and maintenance activities continue to be closely managed by Orion staff to ensure agreed standards are maintained. This work flow is changing with the implementation of the PMO process. Orion have created a new dashboard tool to show asset related information, e.g., condition, performance, expenditure etc. There has also been a significant improvement in the reporting and presenting of public safety related KPI's. The 2022 AMP now contains a lot more asset performance and asset failure trends. This clearly shows where any problem asset areas are and also indicates the improved performance trends resulting from process improvements. 2023 – Orion are looking at utilising AI to simplify the condition assessment process. Access to customer revenue metering data will provide greater granularity of the LV network performance.	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	2022 – Major failures and incidents are investigated on a case by case basis and escalated to senior management for review. There has been changes to the amount of Orion resources currently available to undertake these investigations, both from a asset failure situation and from a health and safety situation. Unplanned outages are reviewed with respect to the root cause and action taken in the field. An Asset Health Index for major asset groups is updated annually. More effort is currently going into the quality and accuracy of this data. All latest updated AMR's include information on a bowtie diagram to assist with a visual representation of the most likely causes of asset failure for a specific asset type, and the associated consequences of the failure. This type of awareness reinforcement is an excellent way to build this area of asset management within the workforce. 2023 – AM standards covered in maninatenance management policies and procedures and support the AMP.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3.13	2022 – Over the past year there has been a continued focus on undertaking more audits of processes, by both internal and external parties. Experienced internal staff have been used to target business and asset areas where potential risks have been identified. From these audits, actions have been raised, approved and improvements implemented, in many cases. 2023 – Orion continues to improve their internal auditing programme to align with changes in the business and wider industry. No significant changes to Auditing have been reported.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3.5	2022 – Improvements in the monitoring and reporting of planned asset maintenance work activities is underway to look to provide improved asset data for future asset reliability analysis. The current process for monitoring maintenance work activities is being mapped out and gaps identified. Promapp may be used to assist this process. 2023 – Enterprise Risk Leads an risk assessment investigation and if the rating is above 'very high' it is escalated to ILT/Board.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3.5	2022 – All documents are reviewed and updated at least annually. Improvement opportunities are investigated and future funded as appropriate. This planned approach helps to keep costs under control. 2023 – Orion's asset management framework has a performance evaluation & continual improvement feedback loop from the delivery phase back into the Asset management objectives and strategies.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3.38	2022 – Orion encourages its staff to attend industry events and seek out new innovations with suppliers and peer organisations. They are looking at areas such as software applications, SF_6 free switchgear, Control Centre system upgrades and alarm rationalisation project, just to name a few. The new org structure will encourage this learning and improving even more, especially for the Future Networks team. 2023 – Orion partners with industry counterparts to commission industry analysis such as the Boston Consulting group. They collaborate with others to explore challenges and opportunities in the sector.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Appendix F Mandatory explanatory notes on forecast information

Company name: Orion NZ Ltd

For year ended: 31 March 2025

Schedule 14a Mandatory explanatory notes on forecast information

Box 1: Comment on the difference between nominal and constant price capital expenditure forecasts

In this AMP:

- In the main body of the AMP, unless otherwise stated, we have expressed all dollars in real terms, as at mid-year FY24,
- In the Report on Forecast Capital Expenditure (Schedule 11b of Appendix E) we have shown expenditure forecasts in nominal dollar terms and in constant dollar terms, as at mid-year FY24.

Our constant dollar forecast figures are the costs we would face, in each of the ten years of the AMP, if there was absolutely no inflation (general or sector specific) witnessed from mid-year FY24 for the next ten years.

Our nominal dollar forecast figures are the costs we would face, in each of the ten years of the AMP, if we include all types of inflation (be it general or industry specific) witnessed from mid-year FY24 for the next ten years.

Our real dollar forecast figures are the costs we would face, in each of the ten years of the AMP, if we include only sector specific inflation that is above or below general inflation witnessed from mid-year FY24 for the next ten years.

In inflating our constant dollar forecast figures, as at mid-year FY24, to nominal dollar forecast figures we have:

- Split our forecast capital expenditure into network capital expenditure and non-network capital expenditure,
- Forecast an inflation index for network capital expenditure aligning with our expectation of the annual cost escalation we will have in our sector over the next decade for network capital expenditure – this will be persistently above general economy wide inflation as increased electrification occurs due to decarbonisation. For more information on this, see Section 2.4.2.10.
- Forecast an inflation index for non-network capital expenditure that is based on appropriate general inflation forecasts received from PwC over the ten-year AMP period.
- Applied the forecast inflation indices for the ten-year forecast period.

In de-escalating our nominal dollar forecast figures to real dollar forecast figures, as at mid-year FY24, we have removed our estimate, based on forecasts received from PwC, of general inflation escalation over the ten-year period.

The inflators we have used are set out in Table Appendix F1.

Table Appendix F1 Inflators used in our capital expenditure forecasts

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Network capital expenditure										
Constant FY24 $ to Real FY24 $	1.045	1.096	1.140	1.172	1.199	1.226	1.255	1.283	1.313	1.343
Real FY24 $ to Nominal $	1.041	1.064	1.085	1.107	1.129	1.152	1.175	1.199	1.223	1.248
Non-network capital expenditure										
Constant FY24 $ to Real FY24 $	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Real FY24 $ to Nominal $	1.000	1.054	1.073	1.093	1.113	1.134	1.155	1.176	1.197	1.210

Box 2: Comment on the difference between nominal and constant price operational expenditure forecasts

In this AMP:

- In the main body of the AMP, unless otherwise stated, we have expressed all dollars in FY24 real terms, as at mid-year FY24.
- In the Report on Forecast Operating Expenditure, Schedule 11b of Appendix E, we have shown expenditure forecasts in nominal dollar terms and in constant dollar terms, as at mid-year FY24.

In inflating our constant dollar forecast figures, as at mid-year FY24, to nominal dollar forecast figures we have:

- Split our forecast operating expenditure into network operating expenditure and non-network operating expenditure.
- Forecast an inflation index for network operating expenditure aligning with our expectation of annual cost escalation being persistently above general economy wide inflation in the decades ahead as increased electrification occurs due to decarbonisation. Further information on this is contained in Section 2.4.2.10. For our vegetation management budget that is contained within network operating expenditure, we have applied a lower inflation index reflecting a significantly higher labour component, and lower materials component, to this activity.
- Forecast an inflation index for non-network operating expenditure that is based on appropriate general inflation forecasts received from PwC over the ten-year AMP period.
- Applied the forecast inflation indices for the ten-year forecast period.

In de-escalating our nominal dollar forecast figures to real dollar forecast figures, as at mid-year FY24, we have removed our estimate, based on forecasts received from PwC, of general inflation escalation over the ten-year period.

The inflators we have used are set out in Table Appendix F2.

Table Appendix F2 Inflators used in our operational expenditure forecasts

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Network operating expenditure, excluding vegetation management										
Constant FY24 $ to Real FY24 $	1.017	1.041	1.059	1.071	1.080	1.090	1.099	1.109	1.119	1.129
Real FY24 $ to Nominal $	1.041	1.064	1.085	1.107	1.129	1.152	1.175	1.199	1.223	1.248
Vegetation management										
Constant FY24 $ to Real FY24 $	1.010	1.028	1.039	1.047	1.052	1.058	1.063	1.069	1.075	1.081
Real FY24 $ to Nominal $	1.041	1.064	1.085	1.107	1.129	1.152	1.175	1.199	1.223	1.248
Non-network operating expenditure										
Constant FY24 $ to Real FY24 $	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Real FY24 $ to Nominal $	1.031	1.052	1.074	1.096	1.113	1.136	1.156	1.179	1.201	1.227

Appendix G Certificate for year-beginning disclosures

Schedule 17. Certificate for year-beginning disclosures

Clause 2.9.1

We, Paul Munro and Mike Sang, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Orion New Zealand Limited prepared for the purposes of clauses 2.4.1, 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 Orion New Zealand Limited's corporate vision and strategy and are documented in retained records.

Director	15 March 2024 Date
Director	15 March 2024 Date

Orion

Orion New Zealand Limited
565 Wairakei Road

PO Box 13896
Christchurch 8140

+64 3 363 9898
oriongroup.co.nz