Orion

Orion New Zealand Limited
Asset Management Plan

Asset Management Plan 2022

Cover: A view of the Canterbury Plains from the Port Hills, with New Zealand's fastest growing town, Rolleston, in the mid ground.

Tēnā koe

These are challenging times to be planning the future of an electricity network. As we navigate this era of change in our industry and our world, one thing is certain: our customers need us to be ready for them to make the most of what the future holds.

This Asset Management Plan charts Orion's plans to develop and manage our network to meet the changing needs of our community. At its core, it delivers on our commitment to 215,000 customers in central Canterbury to provide one of the most safe, reliable and resilient electricity networks in New Zealand.

We are also building a network that is ready for the future. Our 2022 Asset Management Plan ensures we provide the infrastructure to support continued strong growth in our region. It also outlines the beginning of the Orion Group's journey to explore new ways to serve our community in changing times - to deliver on our Purpose:

To power a cleaner and brighter future for our community

Here at Orion we look forward to playing an important role in delivering an exciting energy 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: participants in our Powerful Conversations workshops provide their views on various decisions facing Orion.

Introducing our 2022 Asset Management Plan

This Asset Management Plan sets out Orion's asset management policy, strategy, practices and expenditure forecasts for the next 10 years from 1 April 2022.

We share who we are and where we are headed, the changes in our operating environment, the risks we face in managing our assets, what our customers are telling us, the condition of our assets and distribution system, how we plan to care for and enhance them, and how we support the delivery of this plan.

At the heart of this plan is our desire to balance the three often conflicting dimensions of the World Energy Council's definition of energy sustainability, the Energy Trilemma: energy security, energy equity, and the environmental sustainability of energy systems.

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. We've also been preparing for a different future – one that focuses on expanding our value to the community.

While placing our feet firmly on the ground, we're excited to be exploring new opportunities that will set a new, dynamic direction for our future contribution to powering a cleaner and brighter future for our community.

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Our business is adapting to change

We are adapting to rapidly evolving customer needs fueled by technology that is opening a world of new options for powering their lives and businesses. Also compelling change is the climate emergency which drives the need for New Zealand to transition to a low carbon economy.

We have challenged ourselves to think about what that changed future holds, and how the Orion Group needs to evolve and adapt to remain relevant and proactively harness opportunities in a fast-changing energy landscape.

Our Purpose and Group Strategy have set a new, dynamic direction for the Orion Group that will lead us into new areas beyond our traditional electricity distribution role.

While we look to new horizons, we remain strongly focused on our core electricity network which is the foundation of the service we provide to our community. This too will evolve as the energy sector's new era unfolds.

Throughout this AMP, two factors are strongly reflected in our network's programme of work.

Firstly, there are increasing demands on our infrastructure due to sustained strong growth in our customer numbers. We continue to experience higher than average growth in our residential customer numbers as more multi-dwelling units are built, suburban intensification grows in Ōtautahi Christchurch and new housing developments continue to expand in the Selwyn District and Halswell areas.

Secondly, also strongly reflected in this AMP are our plans to evolve our network to serve our customers' changing needs in a very different energy future.

What's new, what's changed?

As we prepared this year's Asset Management Plan we were conscious of the rapid rate of change in our business context, our customers' needs, and in the world around us. It was important for us to review and adapt our planning to suit changing circumstances - to remain relevant. From our AMP 2021, we have made the following significant changes:

- **Heightened our focus on the climate emergency** and our commitment to reducing our carbon emissions
- **Implemented organisational change** to deliver our **Group Strategy and better serve our community** in the future
- **Established our Project Management Office** and Connetics as our **Primary Service Delivery Partner**
- **Increased our engagement** with our iwi partners
- **Adopted an Enterprise Risk Management approach** and re-elevated the Alpine Fault risk
- **Adjusted our programme of work because of COVID-19** impacts on our supply chain and equipment costs
- **Commenced development of an integrated Customer Relationship Management (CRM) system** to improve operational efficiency and customer service
- **Provided more commentary and expenditure on the LV network** that is both connections driven and proactive reinforcement

Managing new risks

We have broadened our approach to managing our risks.

Orion has adopted the Enterprise Risk Management (ERM) approach which ensures we have a complete, integrated, group-wide focus on managing our strategic and operational risks. ERM also enables Orion to make clear decisions around opportunities.

We regularly evaluate our risks and mitigation strategies.

Based on new research, we have reviewed our crisis management processes, business continuity and expenditure plans to ensure we are prepared for the increased likelihood of an Alpine Fault earthquake.

As an essential service provider Orion has been acutely conscious of our responsibility to maintain vital power services to our community throughout the COVID-19 pandemic. Orion is now very accustomed to working to ensure we can continue to maintain essential power services to our community and help in limiting the spread of COVID-19.

We have also factored the pandemic's impact on our programme costs and supply chain into our financial and project planning.

COVID-19 remains an important factor in our operating environment. We monitor this situation closely as it continues to evolve and proactively manage our risk through a range of measures.

Ensuring customer experience and performance meet targets

In a changing world, seeking out our customers' views and giving them a voice in our decision making is common sense. Being customer-centric means we champion what is important to our customers when making our asset investment decisions and consider their needs in our asset management practices. We ask customers for their perspective on a wide range of topics including investment priorities, how we might improve our communications, our approach to preparing for the future, who is responsible for keeping trees away from power lines and their opinions on different pricing scenarios.

We measure our customers' satisfaction with our performance through a robust annual research programme. We are proud to report our customers continue to rate us highly and provide us with insights that help identify opportunities to improve our performance. See Figure 4.3.1.

We measure our performance in asset management practice through an independent assessment by WSP Opus using an industry recognised tool, AMMAT. In our latest assessment WSP Opus determined that Orion's strong asset management leadership and our focus on continuous improvement were reflected in our achievement of an outstanding score of Competent or Excellent in all categories. See Figure 2.9.2.

COVID-19 remains an important factor in our operating environment.

For our performance against rigorous targets set by the Commerce Commission and those we set ourselves, see Table 4.5.1.

Data and digital drive improvements

We are increasingly using deeper levels of data analysis to inform our asset lifecycle management approach and improve customer service.

Drawing data together from a range of sources into a risk assessment matrix, we have implemented a new inspection and replacement programme for our subtransmission pole fleet. Our new approach is identifying at risk poles more accurately, improving the efficiency of our replacement programme and most importantly, ensuring public safety.

We have established the basis of a Customer Relationship Management system (CRM). An integrated CRM is the foundation for building a single view of a customer and their various touch points with us. It will provide enhanced digital channels for our interactions with customers to provide a high level of service in a more complex future. For an overview of the other systems and process we use to manage our network, see Section 8.7.

In a changing world, seeking out our customers' views and giving them a voice in our decision making is common sense.

Planning our network for growth and new technology

Our capital expenditure keeps pace with the growing demand on our network. This growth is both in the number of customers we serve, and energy demand.

To support growth, eight of our ten significant programmes of work expand our network capacity and increase resilience.

We are also investing in readying our network to enable our customers to take advantage of technologies that give them new ways to self-manage their energy consumption.

An increasing number of customers are considering installing solar PV, putting excess solar generation or power stored within a charged battery back into the grid, and considering a move to electric vehicles. This means our customers' usage patterns are becoming more complicated as energy sources become embedded across our distribution network. Our two programmes for LV monitoring and reinforcement are an important step towards ensuring our network is ready to help power the future needs of the community. See Table 1.1.

When planning our programme of work for the coming year, we have considered the impact of COVID-19 on our supply chain and equipment costs. COVID-19 has caused extended manufacturing and delivery times for some equipment which has delayed the commencement of some projects. We have also factored in the impact of increased equipment costs and have deferred lower priority works.

Our project timings and budgets are set in an ideal world which we know is not usually how things pann out. Customer's plans change, government implements new policy and new opportunities present themselves. For these reasons, fine-tuning naturally occurs closer to the time of programme implementation.

For a list of our key capital and maintenance projects and programmes, see Tables 1.1, 1.2 and 1.3.

Managing our assets

Orion takes a proactive approach to managing our assets through extensive maintenance and replacement programmes. We believe a planned approach is in the long-term interests of our customers as it minimises outages, addresses assets on a risk basis and is more cost effective. A secondary advantage is that a consistent flow of work maintains the competencies of our people and service providers.

Our network capital expenditure is divided equally between replacement programmes for end of life assets; and major projects and new customer connections.

We reduce the impact of weather and plant failure events by conducting regular proactive programmes and approximately 65% of our network operational expenditure is spent on inspections, testing and vegetation management. The remaining 35% is spent on responding to service interruptions and emergencies, the majority of which occur on our overhead network and are largely weather related.

Restructuring to deliver on our strategy for the future

To help us deliver on our Group Strategy, in October 2021 we reshaped our organisational structure, business model and leadership team to provide the focus and capability we need now and into the future.

The Orion Group is now positioned to embrace a future that calls for a broader approach to the challenges and opportunities presented by the new era in the energy sector. Our new structure has created the framework for us to build a more sustainable business, explore new opportunities to contribute to our community, and be more agile and responsive to our customers' changing needs.

These organisational changes and other initiatives to support our community's evolving needs, delivery of the projects in this AMP and our increased focus on preparing for the future will result in an increase in full time employees (FTEs) over the period of this AMP.

The Orion Group is now positioned to embrace a future that calls for a broader approach to the challenges and opportunities presented by the new era in the energy sector.

Financial forecast

Over the next ten years we are forecasting total capital expenditure of $1.1b and operational expenditure of $822m. We will undertake expenditure wisely and provide our customers with genuine value for that money.

Network capital expenditure

Over the 10 year period covered by this AMP, we project a steady level of network capital expenditure to meet demand from major industrial customers and ongoing strong growth in residential customers. Our capex projections also support maintenance of safety levels, and asset condition for asset fleets and resilience.

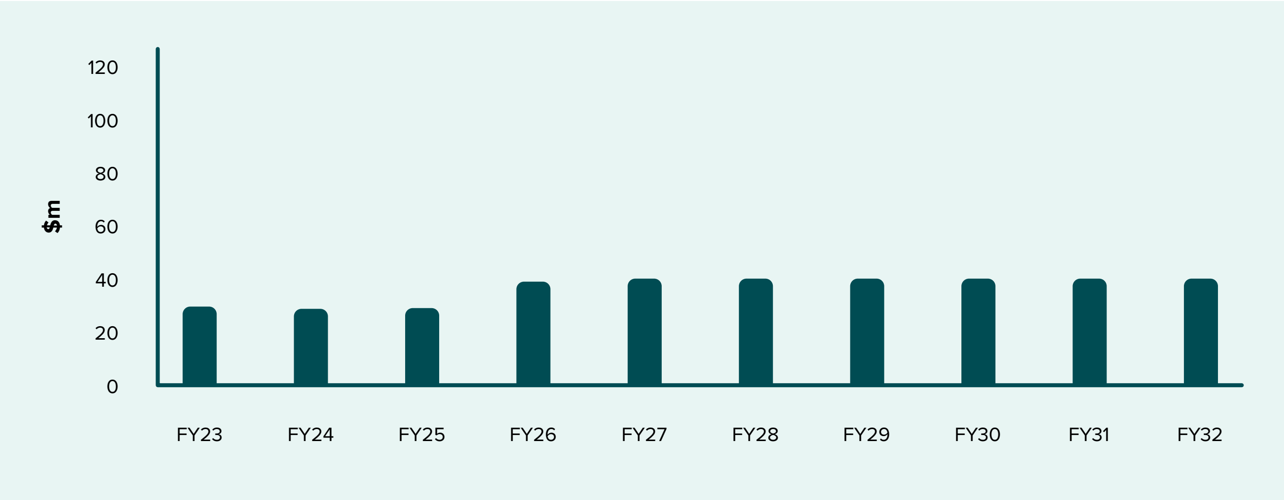
Orion's top ten network development programmes and their drivers over this AMP period are listed in Table 1.1. A list of our capital replacement programmes and their drivers over this AMP period can be found in Table 1.2.

Figure 1.1 Total network capex forecast

Operational expenditure

Our operating expenditure forecast shows an increase from FY26 onwards as we invest in overhead system inspection technology to obtain better condition information about our assets. We have also anticipated increases in labour rates particularly in contract rates with service providers for emergency standby and repair work. Our opex forecast is underpinned by our on-going programme of inspection, testing and monitoring regimes. Our maintenance projects and their strategic drivers over the AMP period can be found in Table 1.3.

Figure 1.2 Total network opex forecast



Expenditure changes from 2021 AMP

Compared to last year's AMP, the main changes in network expenditure over this AMP period are:

An increase of $270m network capital expenditure due to:

- $69m – an increase in major and minor projects due to residential and industrial growth as well as changes in timing of projects to meet changes in customer needs
- $14.5m – an increase in LV projects with a need to reinforce existing networks to cope with steady residential demand increases
- $87m – an increase in asset replacement largely due to new programmes to upgrade our LV network, including the continued rollout of LV monitoring
- $68.5m – an increase in connections capex largely due to the forecast increase in the number of new connections within subdivisions, more multi-dwelling units are built, and urban intensification grows
- $5m – an increase in asset relocations due to a subdivision requiring some 66kV lines to be undergrounded
- $16m – additional costs to procure project management resource
- $10m – an increase in internal labour towards the design and engineering of the increased works programme

An increase of $85m network operational expenditure due to:

- $25m – better scoping and pricing of our overhead refurbishment work
- $60m – allowance to improve vegetation management and better technology to inspect overhead lines

Delivering our works programme

We have transitioned away from a lowest conforming tender model to a Primary Service Delivery Partner (PSDP) contracting model. Connetics undertakes the role of the Project Management Office and contracts construction and maintenance services for overhead, substation and underground assets from Connetics as our Primary Service Delivery Partner and other service providers.

Our new contracting framework became operational in October 2021 and has positioned Orion to more effectively and efficiently deliver the programmes in this AMP.

In the following pages, Tables 1.1, 1.2 and 1.3 we provide a list of our key capital and maintenance projects and programmes and their alignment with Orion Group's strategic themes and project drivers.

Table 1.1 Top ten network development programmes and their drivers for FY23 to FY32

Orion Group Strategy:		**Reimagining the Future Network**	**Customer Inspired**		**Lead & Grow**	**Accelerating Capability**	**Powering the Low Carbon Economy**	**New Zealand's most advanced electricity network**						
Programme or project	**Year(s)**	Engineering alignment and future readiness	Customer experience	Customer driven work	Continuous improvement	Future capability development	Sustainability and environment	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Network security and power quality	Reputation
Region A 66kV subtransmission resilience	FY23-33	✓					✓		✓				✓	
Southwest Ōtautahi Christchurch growth and resilience	FY26-32								✓				✓	
Northern Ōtautahi Christchurch network	FY26-28								✓				✓	
Region B 66kV subtransmission capacity	FY22-24	✓					✓		✓				✓	
Customer driven subtransmission projects	FY22-25			✓			✓							
Lincoln area capacity and resilience improvement	FY23-29			✓			✓		✓				✓	
Rolleston area capacity and resilience	FY25-26								✓				✓	
Hororata GXP capacity and resilience	FY26-30	✓							✓				✓	
LV monitoring programme	FY20-26	✓							✓				✓	
Proactive LV reinforcement	FY23-30	✓					✓		✓				✓	

Primary drivers   Secondary drivers

Table 1.2 Capital replacement programmes and their drivers for FY23 to FY32

Orion Group Strategy:		Reimagining the Future Network	Customer Inspired		Lead & Grow	Accelerating Capability	Powering the Low Carbon Economy	New Zealand's most advanced electricity network						
Asset class	Programme description	Engineering alignment and future readiness	Customer experience	Customer driven work	Continuous improvement	Future capability development	Sustainability and environment	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Network security and power quality	Reputation
Overhead lines	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 drivers   Secondary drivers

Table 1.3 Maintenance programmes and their drivers for FY23 to FY32

Orion Group Strategy:		**Reimagining the Future Network**	**Customer Inspired**		**Lead & Grow**	**Accelerating Capability**	**Powering the Low Carbon Economy**	**New Zealand's most advanced electricity network**						
Asset class	Programme description	Engineering alignment and future readiness	Customer experience	Customer driven work	Continuous improvement	Future capability development	Sustainability and environment	Network performance and PQ improvements	Resilience	Safety	Ongoing opex costs	Network lifecycle economics	Network security and power quality	Reputation
Overhead	Asset monitoring, inspections and maintenance. Emergency works							✓		✓		✓		
	Vegetation management							✓		✓				✓
Underground	Asset monitoring, inspections and maintenance. Emergency works							✓		✓		✓		
Secondary systems	Asset monitoring, inspections and maintenance.							✓		✓		✓		
Primary plant	Asset monitoring, inspections and maintenance. Emergency works							✓		✓		✓		
Power transformers	Transformer refurbishment to ensure asset life is optimised						✓					✓		
Buildings, enclosures & grounds	Inspections and maintenance									✓		✓		✓

Primary drivers   Secondary drivers

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 this Asset Management Plan. Here we reflect on the recent changes in Orion's environment and journey, 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: About our business

We deliver electricity to more than 215,000 homes and businesses in Ōtautahi Christchurch and central Canterbury. In this section we explain how our asset management programme is driven by our Group Strategy, our Asset Management Policy and we set out our project drivers.

Section 3: Managing risk

This section sets out our approach to managing the risks facing our business as a lifeline utility, 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 4: Customer experience

Here we set out the different ways we listen to our customers and other stakeholders. Being close to our customers and keeping up with their changing needs is central to our asset investment decisions and asset management practices.

Section 4 details our customer engagement programme, and our performance against our service level targets for FY21 and our targets for the AMP period.

Section 5: About our network

This section details the footprint and configuration of our network, and our asset management process. Here we explain how Orion uses a lifecycle asset management approach to govern our network assets. This process balances cost, performance and risk over the whole of an asset's life.

Section 6: Planning our network

Here we detail our planning criteria, projections for energy demand and growth, our network gap analysis and list our proposed projects. Maximum network demand is the major driver of investment in our network and here we discuss the factors which are driving demand as our region continues to grow. We also discuss how we are preparing for the future and our customers' adoption of technologies that will impact on network demand and operational management.

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: Supporting our business

This section provides an overview of the Orion teams who together, enable our business to function. It outlines the responsibilities of each team. It also describes organisational changes and other initiatives to support continuous improvement in operational efficiency and our increased focus on preparing for the future.

Section 9: Financial forecasting

Here we set out our key forecasts for expenditure for the next 10 years, based on programmes and projects detailed in Sections 6 and 7. In summary form, we set out our capital and operational expenditure for our network, and the business as a whole, annually from FY23 to FY32.

Section 10: Our ability to deliver

Our ability to deliver our AMP relies on an appropriate level of capable, experienced and skilled resource – both within the Orion team, and via our service providers.

For details of our key philosophies, policies and processes that enable us to deliver our works programme and AMP objectives, see this section.

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

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About our business

Photo: Network Lifecycle Engineer Josh Pope is a member of the team that developed our new power pole assessment and replacement programme. It is an example of how our network upgrades are being increasingly driven by challenges to traditional thinking and data analysis to deliver efficiencies.

Contents

2.1 Purpose of our AMP

Our AMP sets out Orion's plans for the maintenance and development of our network assets and supporting systems to ensure we meet our community's needs now and into the future. It explains the management practices we use to run our electricity distribution business and how our network contributes to the Orion Group Strategy. We update and publish our 10 year AMP in March each year.

In an environment of rapid change and uncertainty, our AMP reflects our best predictions of where we see our network serving our community well in evolving times. We face this uncertainty confident that our people and network have the agility to respond as needed.

We are taking into account these factors:

- continuing strong growth in customer numbers
- changing customer needs and their desire for more affordable energy
- the increasing impact of climate change
- urgency to decarbonise our economy
- the accelerating pace of change
- the rapid development of new technology that provides customers with more options
- the on-going impact of COVID-19, and how pandemics have changed the way we work, and manage our supply chain
- fluctuations in commodity prices

This plan is also created with the knowledge we have today of our customers' plans which can develop or change, sometimes rapidly. We work closely with customers to support their needs, adjusting and adapting our planning as needed and possible.

While this AMP looks ahead for the 10 years from 1 April 2022, we are confident of our ability to be flexible, to adapt to changing circumstances and adjust our planning in both the short and long term as needed.

Our main focus is on the next three to five years, with the highest level of certainty in the first year. Beyond three to five years our forecasts are necessarily more indicative as we respond to adjustments in the expectations of our customers and community.

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. These requirements include:

- a summary
- background and objectives
- target service levels
- details of assets covered and lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives

A cross reference table showing how our AMP meets the regulatory information disclosure requirements is shown in Appendix B.

Our AMP goes beyond regulatory requirements. It also considers what investments we need to make to support our Purpose and Group Strategy. We aim to demonstrate responsible stewardship of our electricity distribution network, in the long term interests of our customers, shareholders, electricity retailers, government agencies, service providers, and the wider community.

We will optimise the long term costs at each point in the lifecycle of every network asset group to meet target service levels and future demand.

2.2 Our business

We own and operate the electricity distribution infrastructure powering our customers and the community in Ōtautahi Christchurch and central Canterbury. 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 215,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business.

Orion has a fully owned subsidiary, industry service provider Connetics, and together with Orion the two organisations make up the Orion Group.

Under economic regulation we are subject to a five-year Default Price-Quality Path for FY21 to FY25.

Rapidly changing technologies and New Zealand's drive for a low carbon future are providing opportunities for our customers to produce, store, and consume electrical energy rather than simply consuming energy provided to them. This is changing the way we and our customers are thinking about electricity, and will alter the demands on our network assets and the services our customers require. It is vital we enable customers' choices for their energy supply and provide open access to our network. While many may choose a degree of independence, the large majority of our customers will continue to rely on power provided by our network, if only as a back-up service.

Electricity distribution is an essential service that underpins regional, community and economic wellbeing. It also has a critical part to play in New Zealand's transition to a low-carbon economy. Orion is confident it has the agility and capability to continue to serve its customers well in an evolving energy landscape.

2.3 Our local context

Central Canterbury is a place of growth and transformation, embracing change and innovation. Ōtautahi Christchurch, is a revitalised city in the heart of this diverse and vibrant region.

Our service is vital to the wellbeing and livelihood of the people and businesses who live and operate here.

This responsibility drives us to understand more about the impacts of climate change on our operations, so our network and our business can continue to be safe, reliable and resilient. Climate change means central Canterbury is likely to face more severe droughts and more extreme weather events. Warmer summers may change traditional energy consumption patterns. New technologies assisting the transition to a low-carbon economy will also impact our business.

Our report on the Climate Change Opportunities and Risks for Orion provides our community with an understanding of how climate risks and opportunities might impact our business, and what we are doing to prepare for a changed future. In December 2021, we announced our commitment to achieving carbon neutrality for our corporate emissions by June 2022. We were the first electricity company in New Zealand to commit to this ambitious target.

The impacts of issues such as climate change, technology advancements and energy equity play an increasingly significant role in addressing social, environmental and economic issues.

People and businesses continue to be drawn to settle in central Canterbury, and growth in customer numbers reached record levels at 4,100 new customers in FY21. The level of growth is expected to taper off in the medium term. Urban development in Ōtautahi Christchurch's central city in FY21 included new residential developments and the opening of Te Pae Christchurch Convention and Exhibition Centre in December.

We know that people and businesses in our community continue to feel the impact of COVID-19. For Orion, supply chain issues, particularly in relation to increased equipment costs, have affected our network maintenance and upgrade programme and uncertainty around the arrival of some critical equipment requires us to be flexible in our project planning. With world-wide vaccination programmes well underway, our hope is this situation will ease in the coming year.

Orion's network boundaries

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

2.4 Our Group Strategy

2.4.1 Our Group Purpose

Orion's Group Purpose is central to all we do, and is the touchstone for this AMP.

As New Zealand transitions to a low-carbon economy, the energy sector has a critical part to play. Orion has established its Purpose to be a vital player in that transition for our community and our region. We are focused on helping our community realise its dreams for a future that is new, better, and more sustainable over the long term. Our Group Strategy is changing the shape of Orion's contribution - to use the skills and expertise of the Orion Group to meet the changing needs of our community today and tomorrow.

2.4.2 Group Strategy

While it remains critical for Orion to provide our community with confidence in their energy supply, we have also challenged ourselves to think about what a changed future holds, and how the Orion Group needs to evolve and adapt to remain relevant and proactively harness opportunities in a fast changing energy landscape.

Launched in 2020, our Group Strategy is now embedded in our daily conversations and in our planning. While its scope is wider than our AMP, it is the driving force behind our network development and maintenance programmes and initiatives. The foundation of this AMP is Orion's aspiration to be New Zealand's most advanced electricity network. See Figure 2.4.1.

Figure 2.4.1 Group Strategy framework

Our Group Purpose is: ***Powering a cleaner and brighter future for our communities.*** It encapsulates the contribution we want to make to our community's future wellbeing and prosperity.

- **Powering** – conveys our commitment to taking action and reinforces our focus on energy
- **Cleaner** – speaks to our commitment to assisting our region and New Zealand's transition to a low carbon future and being environmentally sustainable
- **Brighter** – reflects our contribution to social and economic prosperity
- **Our communities** – reflects our holistic view that includes our people, our region and New Zealand

Sustainable Development Goals – are a subset of 17 United Nations goals that define global sustainable development priorities and aspirations. We consulted with a variety of our key stakeholders who helped us select the seven goals that were most relevant to Orion, and where we could have the most impact. They provide a common language that enables us to collaborate and form partnerships with other like-minded organisations.

Impacts – we will make a clear, measurable impact in these three critical areas

Strategic themes – are the areas we are focusing on to fulfil our Purpose

Our foundation – underpins all that we do; it is critical we continue to perform our core network role exceptionally

Our enablers – the building blocks that will enable us to achieve our Group Strategy

This AMP delivers on our commitment to operate New Zealand's most advanced electricity network and undertake our core network role to the high standard expected by our customers. It also outlines how our projects and initiatives are aligned to our Group Strategy.

2.5 Asset Management Plan development process

An overview of our AMP development and review process is provided in Figure 2.5.1.

Our Orion Group Strategy sets the direction for our AMP to ensure it delivers on our Purpose. The Group Strategy takes a broad view of every aspect of the Group's activities, both existing and those we are exploring for the future.

The projects set out in this AMP help us deliver on our Group Strategy in our core network business. As our future unfolds we will see our AMP reflecting the growing integration of new initiatives in service of a very different energy future.

Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology. These innovations help us to remain one of the most resilient, reliable and efficient electricity networks in the country and move us closer to achieving our aspiration to be New Zealand's most advanced electricity network.

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 are the result of working together, testing and challenging our thinking, calibrating our direction against customer feedback, and applying an open communication and solutions based approach. Our work programmes are tested with Orion's technical leaders, our leadership team and our board to ensure we are building an efficient and cost-effective delivery plan that meets our customer's expectations.

Our AMP is also presented to the wider Orion team on an annual basis and is a valued reference point for communications with external stakeholders.

A key aspect of our AMP development process is top down challenge of expenditure proposals. Significant, high value business cases and Asset Management Reports (AMRs) are subject to review by management and the board.

Each year we aim to improve our AMP to take advantage of customer insights, new information and new technology.

2.5.1 Statement of Intent

This AMP is guided by our Group Strategy which sets the direction for our Statement of Intent (SOI) and Group Business Plan. The scope of our Group Strategy is wider than our AMP which is focused on our electricity distribution network.

Our SOI sets out the Group's key roles, the scope of our governance and relationship to shareholders, and the Group's intentions and performance targets for the next three financial years.

In accordance with Section 39 of the Energy Companies Act, we submit a draft SOI to our shareholders prior to each financial year. After carefully considering shareholders' comments on the draft, the Orion board approves our final SOI. Our approved SOI is then sent to our shareholders and is published on our website.

2.5.2 Continuous improvement

We commission independent audits of our processes and procedures to ensure we identify opportunities for improvement and keep up to date with industry best practice.

With our culture of continuous improvement, we also actively look for new and better ways to do things in our day to day operations.

During the past year we have made significant improvements, including:

- Transitioning to a "Primary Service Delivery Partner" (PSDP) contracting model that will enhance service providers' capability development and ensure they have dedicated focus on health, safety, quality and the environment.
- Overhauling our pole inspection, data collection and replacement programme to more accurately identify those needing to be replaced and more effectively programme our work, which has increased our operational efficiency and improved public safety.
- Initiating electronic data collection for our tree trimming programme which has given us greater visibility of the work in progress and improved quality control.
- Enhancing the real-time communication with customers in our website's outages section, to provide updates on progress with restoration.
- Operating our auto-reclosers by network segment based on localised weather data, which has reduced power outages.

2.5 Asset Management Plan development process continued

Figure 2.5.1 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
Continuous improvement and monitoring Track performance, report and make operational adjustments to improve efficiency	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	AMP review, challenge	Signal key AMP improvements, and key expenditure step changes/ additions to board Publish AMP. AMP presentation to staff	Incorporate customer expectations and stakeholder interests

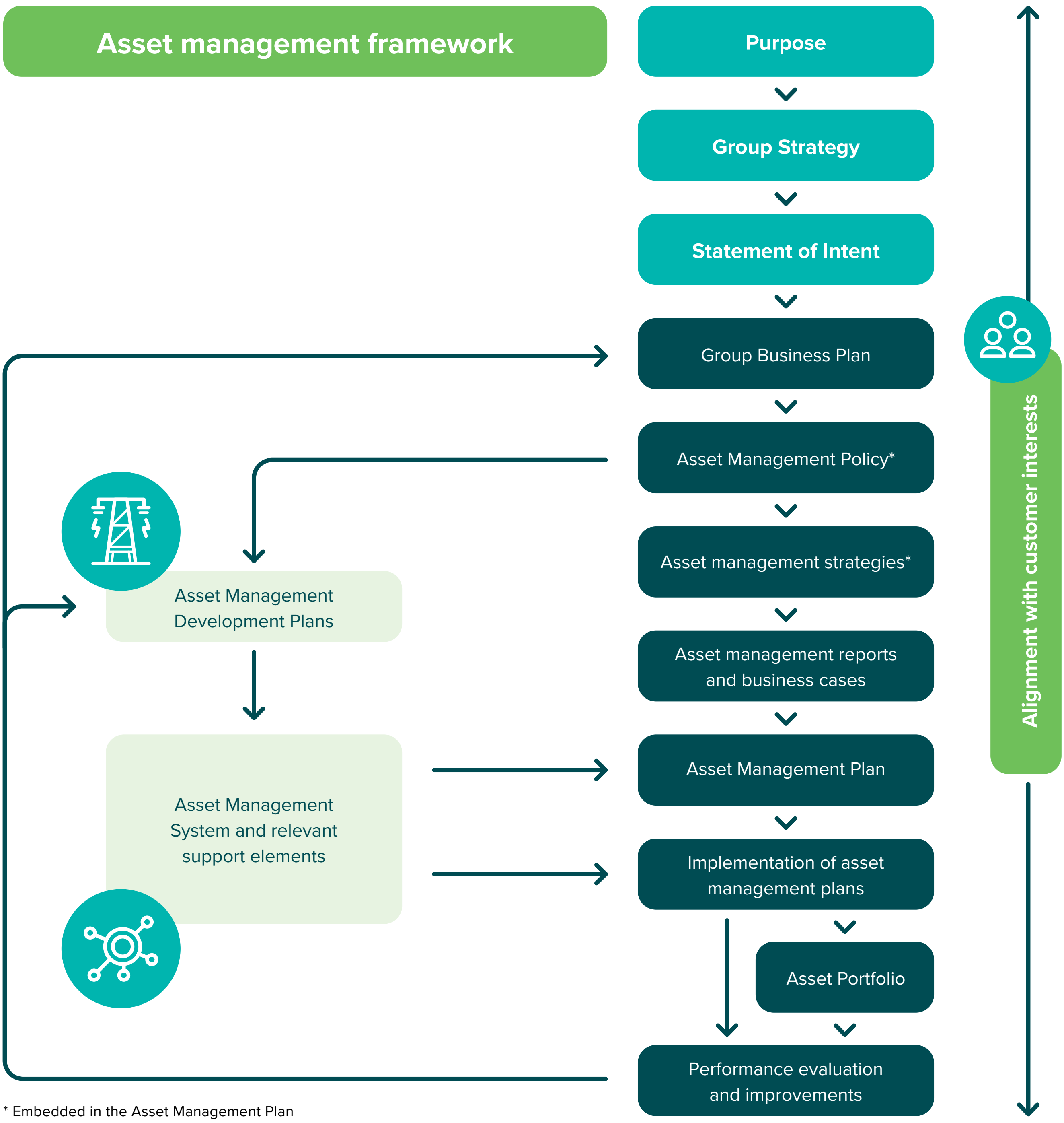
2.6 Asset management framework

Our asset management framework provides structure and process to ensure that:

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

The framework as depicted in Figure 2.6.1 is essentially a hierarchy of documents and processes that provide for clarity of purpose and alignment from our Purpose, Group Strategy, Statement of Intent, Group Business Plan and asset management policy to our investment and operational decisions and actions.

Figure 2.6.1 Orion's asset management framework



* Embedded in the Asset Management Plan

2.7 Asset management policy

Our asset management policy is to use good asset management practices to deliver on our Purpose, Group Strategy and to consistently deliver a safe, reliable, resilient and sustainable electricity service that meets our customers' needs. We are committed to regular reviews of our processes and systems to ensure continuous improvement.

The aims of our asset management policy are to:

1. Enable customer choice
2. Lead a just transition to a low carbon economy
3. Ensure our customers can access the benefits and opportunities that new technology can provide
4. Provide a safe, resilient, reliable and sustainable electricity service
5. Keep costs down and provide value for money for our network investments
6. Meet the long-term interests of our customers and shareholders
7. Embed safe working practices – for our employees, service providers and the public
8. Provide excellent customer service
9. Recruit, develop and retain great people
10. Build effective relationships with relevant stakeholders – including customers
11. Comply with relevant regulatory requirements

Our AMP sets out how we implement this policy, by describing:

- how our AMP fits with 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 key 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 ten-year expenditure forecasts – capital and operating

Our senior leadership and technical leaders review our AMP annually and review planned projects and expenditure forecasts. Our leadership team provides a further review before it is presented to the board for approval.

Our asset management policy is to use good asset management practices to consistently deliver a safe, reliable, resilient and sustainable electricity service that meets our customers' needs.

2.8 Asset management strategy

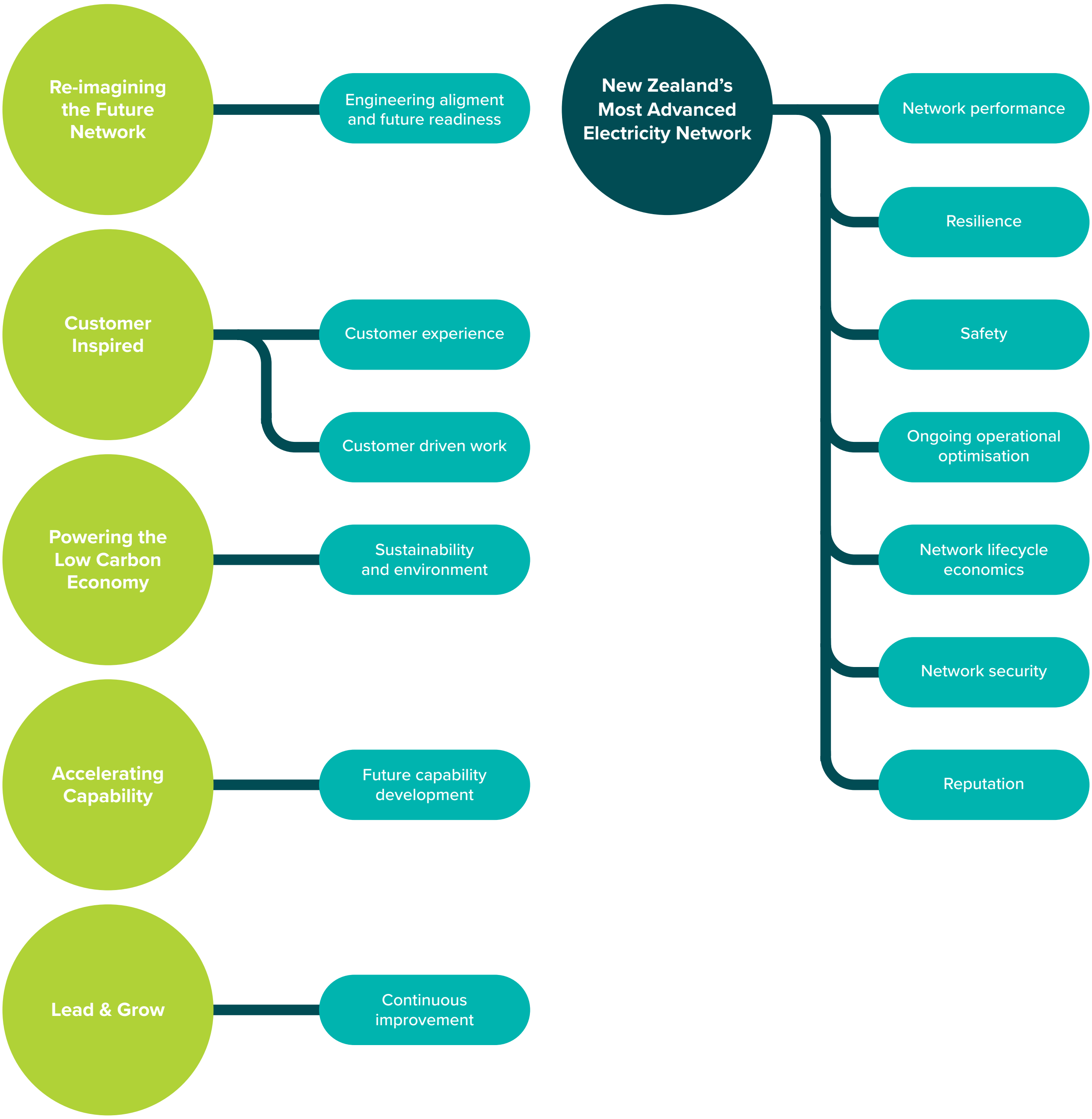
Our asset management strategy translates our Group Strategy into asset investment drivers and asset management objectives at an operational level. These are core considerations in our asset decision making to ensure we deliver on our Purpose and provide the service our community needs, now and into the future.

Our objectives guide the development of our planning and lifecycle activities, programmes of work and forecasts. They support the electricity sector's transition to a low-emission economy and Orion continuing to provide long-term benefits to our customers and stakeholders.

Our asset management strategy reflects the external environment in which our network operates. Community use of electricity and customer expectations are changing. Community dependence on electricity is increasing with the adoption of new technology, electrification of transport and the global movement to a low carbon economy.

We have aligned the drivers of investment in our assets to our Orion Group Strategy, see Figure 2.8.1.

Figure 2.8.1 Alignment of asset investment drivers to Orion Group Strategy



2.8 Asset management strategy continued

Our asset management objectives and their link to the aims of Orion's asset management policy are set out in Table 2.8.1.

Table 2.8.1 Alignment of asset management objectives to Orion Group Strategy and AMP Policy

Orion Group Strategy	Investment drivers	Objectives	AMP Policy aims – see Section 2.7
Re-imaging the Future Network	Engineering alignment and future readiness	Evolve our service and engineering approaches to keep pace with changes in our customers' needs while maintaining standards, architectures and approaches that preserve both optionality and foundation focus areas	1, 2, 3, 4, 5, 11
Customer Inspired	Customer experience	Leverage interactions and enhance engagement with our customers and stakeholders to stimulate participation in our decision making Co-create and deliver personalised end-to-end seamless service experiences Build customer experiences that are consistent across all channels	1, 3, 6, 8, 10
	Customer driven work	Be responsive to customer needs delivering cost effective and timely solutions	1, 2, 3, 4, 5, 6, 8, 10
Lead & Grow	Continuous improvement	Collect and manage optimum data and leverage that data to provide analytics and insights that support informed decision making Maintain and enhance our systems to provide new opportunities to interact with and serve our customers	1, 2, 3, 4, 5, 6, 8
Accelerating Capability	Future capability development	Invest in human capability to enhance future success for individuals, our business and the sector Provide opportunities for our people to grow and contribute to our sector in service of great outcomes for our community	9
Powering the Low Carbon Economy	Sustainability and environmental	Implement initiatives to reduce our carbon footprint Be a proactive enabler of those seeking to reduce their carbon footprint Understand more about the risks and opportunities of climate change for our operations, so our network and our business can continue to be safe, reliable and resilient Support electrification of transport and use of distributed energy resources by enhancing our knowledge of our LV systems	1, 2, 4
New Zealand's most advanced electricity network	Network performance and PQ improvements	Maintain and improve reliability outcomes through enhancement of our operational processes and systems including the integration of equipment and control Make improvements to the Power Quality (PQ) to customers of an existing network	4
	Resilience	Through our collective knowledge, judgement and risk management framework mitigate outcomes from High Impact Low Probability (HILP) events for our community Have an adaptation plan	3, 4
	Safety	So far as is reasonably practicable reduce the potential for harm to our people, service providers and the public from our network assets and activities Systems, processes and competencies set our people and service providers up for safe outcomes Develop and maintain standards, and apply safety-in-design principles that support safe outcomes Investigate incidents to ensure enterprise learning to prevent adverse safety outcomes	3, 4, 6, 7, 9
	Ongoing operational optimisation	Consider the life time implications of decision making on the extent of operational costs Balance ongoing operational costs with other focus areas	5, 6, 8
	Network lifecycle economics	Care for existing assets to maximise their service while maintaining network performance Understand the risk criticality of our assets to inform the timing and extent of interventions	4, 5, 6, 11
	Network security and power quality	Actively monitor network status against our security standard and address emerging constraints in a timely manner When addressing emerging constraints to system security consider scenarios and alternatives including non-network alternatives to address the gap Understand our customers and the choices they are making to inform our decision making around the extent of security required Enhance and address power quality where it has been impacted by system growth	1, 3, 4, 6, 10, 11
	Reputation	Demonstrate vigilance and foresight to minimise events that result in loss such as material or intangible damage and customer and stakeholder dissatisfaction	6, 10

2.9 Asset Management Maturity Assessment Tool (AMMAT)

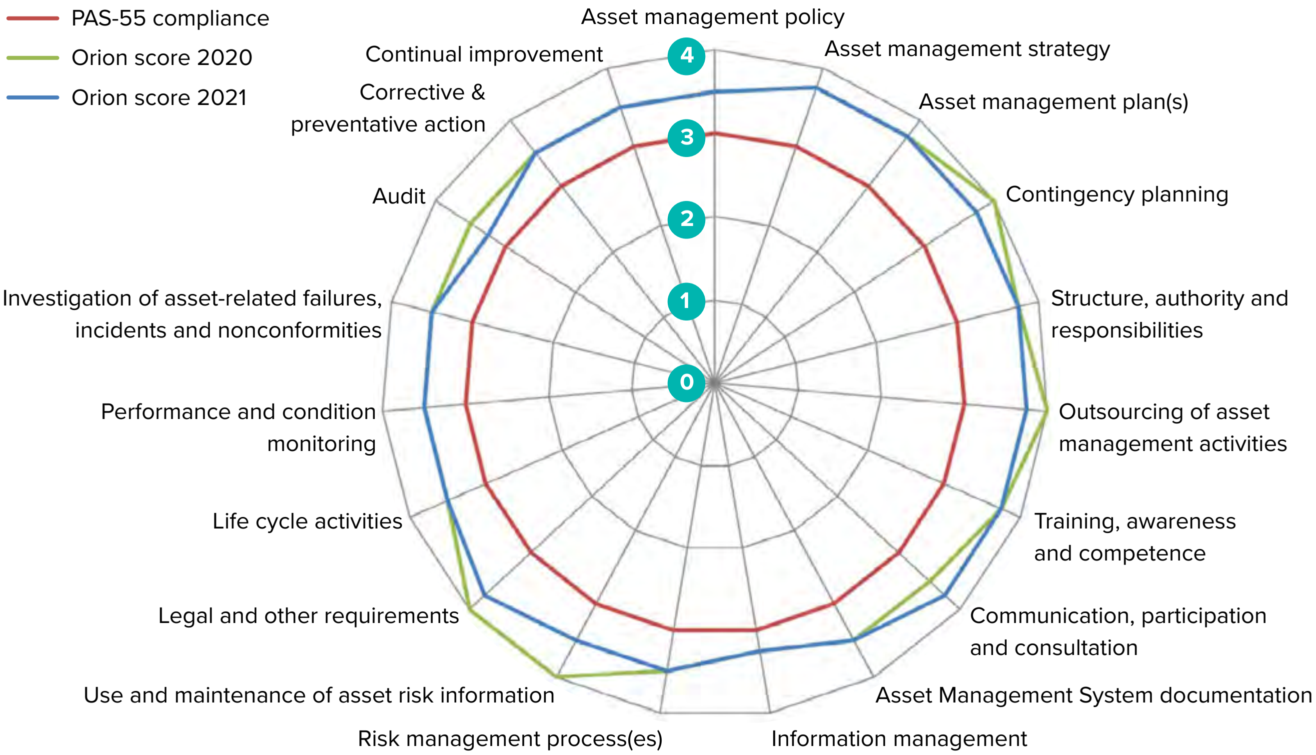
As part of the Commerce Commission's Information Disclosure requirements, EDBs must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT).

An overview of the general criteria the standard requires to be met for each maturity level is shown below.

Figure 2.9.1 AMMAT maturity levels

Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.	The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.	The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.	All elements of the function are in place and being applied and are integrated. Only minor inconsistencies may exist.	All processed and approaches go beyond the requirements of PAS 55. The boundaries of Asset Management Development are pushing to develop new concepts and ideas.
Innocence	**Aware**	**Developing**	**Competent**	**Excellent**

Figure 2.9.2 Orion's maturity level scores



In June 2021 Orion again engaged WSP Opus to undertake an independent assessment based on AMMAT and the EEA guidelines. WSP Opus determined that Orion had narrowly slipped back in five categories as we hadn't implemented improvement opportunities in development that will be reflected in next year's score. The increased score for Communication, participation and engagement reflects new initiatives and additional focus on this area.

Overall, Orion's scores are industry leading and the assessment concluded that: "WSP believed that Orion NZ has engendered the right organisational culture change and approach for long term asset management operations."

For full results see Appendix F, Schedule 13.

2.10 Stakeholder interests

Our key stakeholders and their interests are summarised in Figure 2.10.1.

Throughout the development of our Group Strategy and this AMP we take into account the needs of a variety of stakeholders.

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
- Being a company they can trust

Figure 2.10.1 Stakeholders and their interests

Figure 2.10.2 lists the key ways we identify the views and interests of our stakeholders, support their interests in our asset management planning and practice, and manage conflicting interests that may arise.

Figure 2.10.2 Process for identifying stakeholder interests

Identify interest through forums

1. Customer surveys, workshops, advisory panel and major customer forums
2. Reviews of major events (storms), quality of supply studies
3. Employee engagement surveys
4. Supplier technical assessment meetings
5. Service provider in-depth interviews
6. Contract performance reviews
7. 1:1 relationship management
8. Local government and community group briefings

Support interest in asset management practices

1. Customer demand forecasts
2. Coherent network planning, security of supply standards
3. Safety plans, auditing and compliance programmes
4. Standards and procedures
5. Risk management
6. Asset management reports

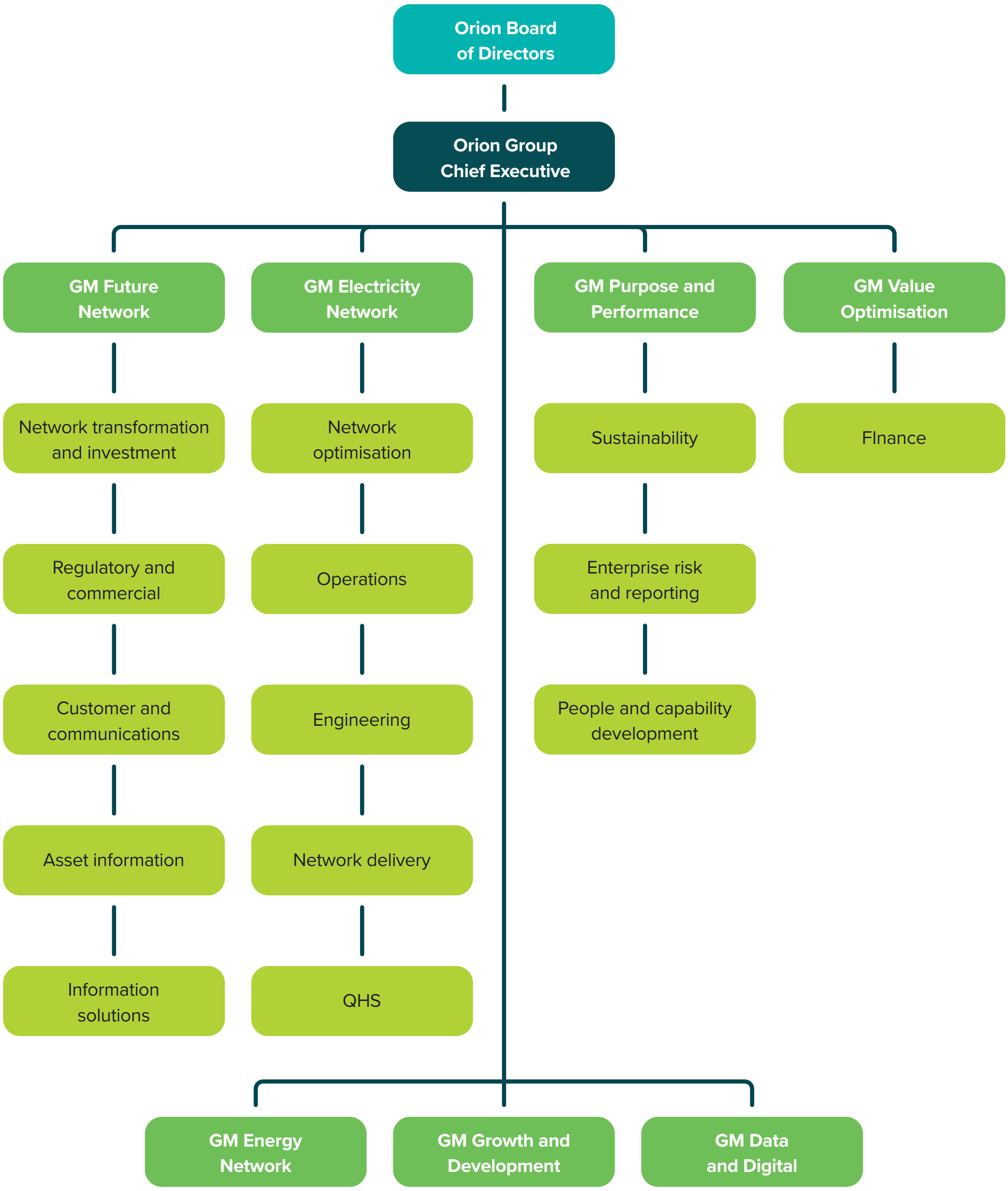
Manage conflicting interest

1. Considering the needs of stakeholders as part of our high level planning
2. Balancing the cost of non-supply and the investments to provide the security desired
3. Cost /benefit analysis
4. Our principal objective pursuant to section 36 of the Energies Company Act being "... to operate as a successful business."

2.11 Accountabilities and responsibilities

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

Figure 2.11.1 Asset management structure



2.11.1 Board and executive governance

Our directors are appointed by our shareholders to govern and direct our activities. The board meets 10 times a year and receives formal updates from the leadership team of progress against strategy, objectives, legislative compliance, risk management and performance against targets.

Orion's board of directors is the overall and final body responsible for all decision-making within the company. The board is responsible for the direction and control of the company including Group Strategy, commercial performance, business plans, policies, budgets and compliance with the law. The board reviews and approves our revised 10 year AMP prior to the start of each financial year (1 April).

The board also formally reviews and approves our key company policies each year, including delegated authorities and spending authorities. Each of the General Managers in the Leadership Team is responsible for their budget and operating within their delegated authorities.

2.11.2 Asset management governance

The asset management framework is governed by the board, leadership team and the transformation and investment team. Each people leader is responsible for their part of the network opex and capex. The expenditure for each asset class is also set out in the internal Asset Management Reports (AMRs), which support this AMP. The AMRs are subjected to an internal approval process where they go through several checkpoints including Orion's senior technical people leaders and leadership team review. A selection will be reviewed by the board.

For detailed responsibilities see Section 8.

2.12 Information systems

Historically, our information systems concentrated on the development, management and operation of our network assets. We continue to evolve these systems to take advantage of new technology and support ongoing improvements in productivity and service to our community.

Increasingly, data and digitisation are being used to inform our decision making and we are extending our capability around data, analytics and operational insights. We are also investing in systems that create new opportunities to interact with and serve our customers.

For a description of the functions of our main systems, see Section 8.7.

Increasingly, data and digitisation are being used to inform our decision making and we are extending our capability around data, analytics and operational insights.

2.13 Significant business assumptions

2.13.1 Asset management processes

2.13.1.1 Business structure and management drivers

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

2.13.1.2 Risk management

The assumptions regarding management of risk are largely discussed in Section 3. Although we have planned for processes and resources to ensure business continuity as a result of a major event or equipment failure, we have not included the actual consequences of a forecast/hypothetical major event in our AMP forecasts.

2.13.1.3 Service level targets

We have based our service level targets on customers' views about the quality of service that they prefer. 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.

See Section 4 for a summary of our recent customer engagement.

2.13.1.4 Network development

Section 6 of this AMP outlines projects that will ensure that our network will continue to meet our customers' expectations of service.

Our network pricing aims to promote active participation from customers, for example, many of our major customers respond to our price signals and reduce their demand when our network is running at peak demand. We maintain a watching brief on Transpower's proposed changes to the Transmission Pricing Methodology, due to take effect in 2023.

Based on our Low Voltage network modelling undertaken to date, we believe the majority of our LV network has sufficient capacity to meet demand in the short to medium term.

The urgency to address climate change through de-carbonising energy generation, transport and production may accelerate the rate of change in energy demands. As electric vehicles are adopted by more households and businesses it is expected reinforcement above historic levels will be required. Data on our low voltage network utilisation will be critical to ensure we keep pace with customer needs.

The Government's response to the Climate Change Commission's report may accelerate the rate of change, and we are seeing an increase in utility-scale solar proposals which if they become a reality may have some impact on network supply and demand. We have assumed that industry rules will ensure that generation connections will not be subsidised by other industry participants, including Orion, or customers.

2.13.1.5 Lifecycle management of our assets

We have assumed no significant purchase/sale of network assets or forced disconnection of uneconomic supplies other than those discussed in the development of our network, see Section 6.

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. Our risk assessments are based on the context of no significant changes to design standards, regulatory obligations and also our other business drivers and assumptions discussed in this section.

2.13.2 Changes to our business

All forecasts in this AMP have been prepared consistent with the existing Orion business ownership and structure.

In October 2021, we transitioned to a Primary Service Delivery Partner (PSDP) contracting model with Connetics undertaking this role.

This new contracting model will help us more effectively and efficiently meet our objectives by enhancing our partnership with service providers. Our aim is to enhance capability development, more efficiently plan work and optimise field resources, and ensure our service providers have dedicated focus on health, safety, quality and the environment.

2.13.3 Sources of uncertainty

Our ability to operate in a climate of uncertainty is essential to our business' sustainability and our ability to keep pace with our customers' needs. We have identified a range of potential uncertainties that could impact our assumptions, and considered a range of scenarios. We face these sources of uncertainty confident in our ability to adjust our planning if needed.

Potential uncertainties in our key assumptions include:

- **Regulation –** future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure for ensuring cost effective delivery of network services. We believe that the structure of our network pricing and our management processes encourage the economic development of the network and the chances of adverse significant changes in the regulatory framework in this regard are low.
- **Climate change –** the Climate Change Commission's urging of the need for New Zealand to take bold and urgent climate action and any significant changes in Government policy could create transformational change in our industry and service provision.
- **Changing customer demand –** the uptake of electric vehicles, photovoltaic generation and battery storage is forecast to increase. These forecasts are uncertain and we have researched the impact of these technologies for different uptake scenarios to inform our thinking.

- **The ongoing development of Ōtautahi Christchurch –** further development of Christchurch's central city and the future of the 'red zone' are influenced by the Crown, Christchurch City Council and Ōtākaro Limited. It is also influenced by private developers.

  There is uncertainty regarding the timing and extent of some key development projects.
- **High growth scenario –** growth scenarios form a relatively narrow range. Our peak demand forecasts include a range of scenarios to test the impact of changing energy generation, consumption and storage scenarios. The high growth scenarios do not cause a material uplift in network constraints and hence a material uplift in network investment or service provider resource requirements. Large capacity requests from major customers create manageable uncertainty.
- **Resourcing of skilled service providers and employees due to demand –** Powerco successfully applied to the Commerce Commission for a CPP and other EBDs Wellington Electricity and Aurora have followed. This will put further upward pressure on labour rates and availability in the next period.
- **COVID-19** – supply chain issues and uncertainty around the extent and duration of the COVID-19 pandemic, or other pandemics, may impact the plans described in this AMP.

2.13.4 Price inflation

In this AMP our cost forecasts are stated in real dollars in FY22 terms. For some of our regulatory disclosures in Appendix F – the Report on Forecast Capital Expenditure (Schedule 11a) and the Report on Forecast Operational Expenditure (Schedule 11b) – we allow for price inflation and forecast in nominal dollars in certain components of the schedules.

We base our inflation assumptions on forecast information provided by PwC. PwC uses and extrapolates information provided by NZIER. We generally apply a labour cost index (LCI) to the estimated labour component of capital and opex, and a producer price index (PPI) to the other components of our capital expenditure and operational expenditure.

We adjust the LCI forecast provided by PwC to reflect our local view of wage and salary increases. This affects nominal information contained within the system operations and network support and business support forecasts contained in Appendix F, Schedule 11b.

2.13.5 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 timing of our network projects
- one or more large energy customers/generators may connect to our network requiring specific network development projects
- Government measures to keep New Zealanders safe from any escalation in COVID-19 or other pandemics may impact resource availability and delay our work programme
- major equipment failure, a major natural disaster or cyber attack may impact on 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 economics associated with some projects. If higher costs are anticipated, some projects may be abandoned, delayed or substituted
- changes to industry standards, inspection equipment technologies and understanding of equipment failure mechanisms may lead to changing asset service specifications
- requirements for us to facilitate the rollout of a third party communications network on our overhead network could lead to substantial preparatory work to ensure the network is capable of meeting required regulatory and safety standards. This could lead to resource issues and short-medium term increases in labour costs

Supply chain issues and uncertainty around the extent and duration of the COVID-19 pandemic, or other pandemics, may impact the plans described in this AMP.

3 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

3.1 Introduction

Prudent risk management strengthens our ability to provide an electricity delivery service that is safe, reliable, resilient and sustainable.

In 2021 the Orion Group adopted an Enterprise Risk Management (ERM) approach which ensures we have a complete, integrated, group-wide focus on managing our strategic and operational risks. ERM also enables Orion to make clear decisions around opportunities.

Our ERM programme:

- supports the Orion Group's Purpose, strategy and objectives
- supports our community's aspirations for a 'liveable' region that has strong connected communities, a healthy environment and a prosperous economy
- identifies and manages significant and emerging risks
- enables us to make clear decisions around the opportunities that are inherent in some risks
- stimulates continuous improvement

Our approach to ERM is grounded in our belief that:

- every person has a responsibility to identify and manage 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 key stakeholders
- we can always improve

3.2 Our risk context

Our risk context is complex and dynamic. The energy sector is moving through a period of unprecedented change, while at the same time, we are contending with the global challenges of climate change and the COVID-19 pandemic.

Electricity is a fundamental necessity in the modern world particularly as our community shifts away from fossil fuels. We expect this reliance on our service to continue for the long-term.

Our community will increasingly depend on our electricity distribution service, so it's essential we identify and manage our key risks. Our community especially depends on electricity during and after high impact low probability (HILP) events such as major earthquakes or storms.

Our lifelines responsibilities are set out in Section 60 of the Civil Defence Emergency Management (CDEM) Act. As a key lifelines utility, we '*... must be able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency.*'.

As further context, our service region:

- is a significant earthquake zone. For example, recent research from Te Herenga Waka–Victoria University of Wellington estimates that there is a 75% chance of a major Alpine Fault earthquake in the next 50 years
- has cold winters and is subject to weather extremes – including snow and/or wind storms
- has no reticulated natural gas
- has urban 'clean air' restrictions on the use of solid fuel heating

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 carbon-based fuels to renewable energy sources

Our community will increasingly depend on our electricity distribution service, so it's essential we identify and manage our key risks.

- our customers will increasingly inject energy back into our electricity distribution network
- global risk sources such as pandemics and cyber-crime are increasing in their likelihood and potential consequences
- the pace of technology change will continue to increase
- other lifelines 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 our principal objective shall be to operate as a successful business
- we are publicly accountable to our customers, our community, our shareholders and industry regulators
- our shareholders are also publicly accountable to our community

3.3 What our community wants from us

In light of our risk context and through our ongoing customer engagement, we know our customers and community want us to provide a safe, reliable, resilient and sustainable electricity delivery service – see Sections 4.2 and 4.3.

Our previous earthquake experience tells us High-Impact-Low-Probability (HILP) events can cause extensive damage to our assets and prolonged power outages.

Our customers and community may suffer extreme adverse impacts financially or on other dimensions of their wellbeing from prolonged or frequent interruptions to their power supply, especially if they happen in winter.

For these reasons, we will:

- use the most reliable and comprehensive information to identify, assess and treat our key risks
- apply our experience, knowledge and good judgement to take reasonably practicable and timely steps to treat our key risks, including those driven by climate change

We especially focus on our critical network assets and systems, for example our network control systems and our 33kV and 66kV sub-transmission assets, as these high voltage assets supply the greatest numbers of our customers and they can be the most complex to repair or replace if they are damaged.

3.4 Our approach to risk management

3.4.1 Our Enterprise Risk Management process

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

3.4.2 Our risk management appetite

In matters of health and safety and key operational risks, our risk management appetite remains low. In other areas our risk management appetite is assessed to consider the potential upside in a situation, and how we might manage our response to leverage the possibilities it presents.

3.4.3 Our climate change risk management

Climate change presents risks and opportunities to Orion strategically, in addition to those it presents in our physical environment and operationally. To effectively deliver on our Purpose - Powering a cleaner and brighter future for our community - we must consider the risk and opportunity inherent in changing strategies, government policy or investments as our community works to reduce its carbon emissions.

We group the opportunities and risks related to climate change into three categories:

- **upside growth opportunities** – demand for our electricity delivery service will continue to grow as our community continues to shift from burning fossil fuels to renewable electricity
- **physical risks** – these can be event-driven, such as more frequent and severe storms, or longer-term shifts such as gradual rising temperatures and sea levels
- **transition risks** – these can be wider changes with strategic impacts – such as to the economy, regulation, technology, insurance markets or community preferences and behaviours

Overall, we continue to believe that our upside growth opportunities from climate change will outweigh our physical and transition risks over the next ten years. In fact, we believe that we have an important role to help our community decarbonise – for example by encouraging the uptake of EVs and the conversion of process heat to electricity. This continued growth and reliance on electricity reinforces our asset management strategy to continue to invest to have a safe, resilient, reliable and sustainable electricity distribution network.

Our largest potential operational impacts relate to vegetation and more frequent and severe storms that will affect our largely overhead rural network. We worked with NIWA during 2021 to quantify the risk to our overhead network from our changing climate.

We already engineer and lifecycle-manage our network to be resilient to storms and have active vegetation management programmes in place. Our team continues to improve our understanding of climate effects on our network to adapt and mitigate risks where appropriate, or reasonably practicable.

We assess our transition risks as moderate over the next ten years, with the largest potential impacts relating to the pace of introduction of new technology and the speed of any transition. Because of the unknown nature of these changes and the technology that accompanies them, we prefer to view this risk as an opportunity. We believe our

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

best management lies in promotion of an adaptable and agile business that can quickly adopt or accommodate new innovations. Adverse regulation could also potentially impact the level or structure of our delivery pricing, or could relate to operational aspects of our business.

In 2020, we published our first annual report in accordance with the guidelines published by the Task Force for Climate-related Disclosures (TFCD). Our *Climate Change Opportunities and Risks for Orion* report is available on our website.

3.4.4 Our network risk management

We are proactive and prudent managers of central Canterbury's electricity network. We continuously improve how we:

- forecast customer demand for our services – including the potential impacts of new technologies, climate regulation and our changing environment
- plan and build for network safety, capacity, resilience and reliability
- monitor, maintain and enhance the condition of our key assets and systems via our ongoing lifecycle management
- operate, monitor and control access to our network
- maintain an appropriate level of redundancy and emergency spares
- maintain and develop competent employees and service providers
- maintain an effective vegetation management programme
- otherwise identify, assess and manage our key risks

3.4.5 Our people risk management

We achieve effective risk management via our people, and our aim is to have:

- a healthy and safe workplace
- a resilient 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 – 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 aspiration is to be an employer of choice. Our focus on the wellbeing of our people, flexible working practices and a learning environment support us on this journey.

3.4.6 Our commercial and financial risk management

Our revenue supports ongoing investment to meet the long-term interests of our shareholders, customers and community. 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

3.4.7 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.

3.4.8 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 a number of 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

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

3.5 Our risk management responsibilities

3.5.1 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 regularly reports to the board on key risks, emerging risks and environmental context.

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 three teams that support line management to undertake risk management:

- **Head of Group risk and reporting** – coordinates our management and governance processes, our ERM framework and our insurance programme
- **Quality, Health, Safety** – six FTEs help our line management to continuously improve our processes in these areas
- **Risk steering committee** – this was established in 2020 as an ongoing cross-functional and diverse team of people leaders and employees who provide support, guidance and oversight to the organisation's identification and management of current and emerging risks.

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

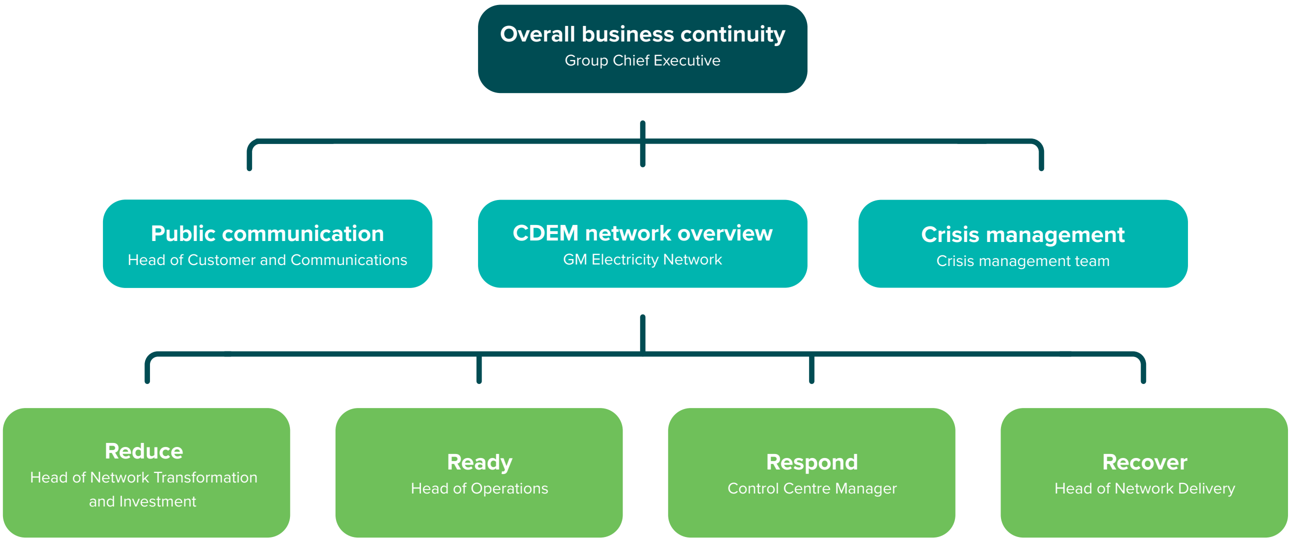
3.5.2 Our HILP/crisis risk management

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.

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

3.5 Our risk management responsibilities

Figure 3.5.1 Our HILP and crisis risk management responsibilities



- **Reduce** – means we implement measures in advance so that the impacts of future HILP events will be less. An example of this is that we are planning to replace the remaining 40km of our oil filled 66kV cables which are vulnerable in an earthquake - a risk that is heighted with the increased chances of an Alpine Fault earthquake. We have also 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 key service providers have planned workflows that can be put on hold when HILP events occur.

  Our readiness delivers on our focus to continually improve our network and business resilience. Addressing this foreseeable risk means that in the event of a major event, 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 has occurred and the main impacts, and we then plan and prioritise measures to ensure a response that has the greatest benefit for the greatest numbers of customers in the shortest practicable time – this approach is what we refer to as plan-to-plan.
- **Recover** – means we deal with the medium to long term impacts 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.

  A good example of this is that following the Canterbury earthquakes, we invested to increase the resilience of our network IT and communications systems, our 66kV underground cables in the east and north of Christchurch, and our base for our key emergency service provider, Connetics.

Our readiness delivers on our focus to continually improve our network and business resilience.

3.6 Our risk assessments and risk evaluations

3.6.1 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 help 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 3.6.1.

Table 3.6.1 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 ratings
Extreme
Very high
High
Medium
Low

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 aim to 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 the risk that our current risk treatments and controls are ineffective

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

3.6.2 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 3.6.1.

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 3.6.1 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 3.6.2.

Table 3.6.2 Our risk treatment and escalation guidelines

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

3.7 Our key operational risks

Our key operational risks are:

Table 3.7.1 Our key risks

Key risks	Examples
Health and safety	Fatality or permanent disability to a worker, service provider or other person
Natural disaster	HILP events – for example, major earthquake, tsunami triggered by a major earthquake or severe storm
Weather event	Weather event that results in significant business disruption – becoming more frequent due to climate change
Serious cyber security breach	Security breach that especially affects our network control systems
Pandemic	Pandemic that causes business continuity issues; impacts on costs, the supply chain, people capacity
Major network asset failure	Extensive network asset damage and/or extended outages to many customers

Our overall assessments for these key risk categories are shown in Table 3.7.2. The ratings in Table 3.7.2 are as at March 2022, and are regularly reviewed.

Table 3.7.2 Our overall operational key risk assessments

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

1. Serious health and safety incident that causes a fatality
2. Serious health and safety incident that causes serious injury
3. Major earthquake – could also trigger tsunami
4. Weather event
5. Pandemic
6. Cyber security breach
7. Major network asset failure

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

3.7.1 Health and safety

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're 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.

In addition, our Health and Safety and our Public and Asset Safety Committees have employee representatives from across Orion who meet regularly to review incidents, 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 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.

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.

3.7.2 Natural disaster

3.7.2.1 Major earthquake

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 recent Te Herenga Waka–Victoria University of Wellington study indicates a 75% chance of a major Alpine Fault earthquake in the next 50 years. The research 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 moved the likelihood to possible. We have reviewed our crisis management processes and business continuity plans to ensure that we are prepared for this increased likelihood.

Our region's greatest natural disaster risk is a major earthquake.

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. A major Alpine Fault earthquake may result in a major outage of up to seven days to significant parts of our network – and the impacts of that 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 next major planned resilience initiative is to replace the remaining 40km of oil filled 66kV cables over ten years or so – starting in FY23. These cables represent old technology and the skills to maintain and replace them if they become damaged are increasingly rare internationally and locally.

These were the type of sub-transmission cables that failed in the eastern suburbs in the 2011 earthquake and we had to abandon and replace them completely.

These cables may be susceptible to a series of prolonged tremors from a major Alpine Fault earthquake – including significant aftershocks. Christchurch has significantly developed to the west since 2011, so there is an increasing dependence on a resilient electricity supply in that area of our region.

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.

3.7.2.2 Tsunami

Another major natural disaster risk is tsunami, most likely from a major earthquake offshore. This could result in an outage of up to three days in areas of our network near the east coast. Since 2011, we have significantly reduced the potential impacts of a major tsunami as our key service providers have moved their depots significantly further inland. Our network assets near the east coast will inevitably be exposed to tsunami, particularly as climate-related sea level rise increases.

3.7.3 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 learnings from a major wind storm in 1975, snow storm in 1992 and wind storm in 2013 – 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.

Our urban network is largely underground – and so our weather risks mainly relate to our widely dispersed rural overhead lines.

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. In the most severe storms, most of the trees and branches concerned are well outside regulatory notice or cut zones.

Our next major planned resilience initiative is to replace the remaining 40km of oil-filled 66kV cables over ten years or so – starting in FY23.

Our urban network is largely underground – and so our weather risks mainly relate to our widely dispersed rural overhead lines.

There is currently no scope for us to require private tree owners to remove such hazards if the trees and branches are outside a regulatory cut zone. In order to reduce this risk, we have an active vegetation management programme that aims to:

- ensure tree owners comply with the tree regulations
- enlist the long-term support of tree owners to reduce threats to our rural overhead network

Important risk assessment context includes:

- we have gradually improved the resilience of our rural overhead network over the last 25 years via our asset lifecycle programme
- we have also invested to improve our network switching capability in rural areas – in order to better isolate affected areas so that we can reduce the number of customers affected by network damage in many circumstances
- overhead networks are generally more susceptible to outages caused by trees, but they are faster and less expensive to repair than underground cables

We believe that flooding is a medium to low risk for our network. We expect that localised floods will occur from time to time near the Avon and Heathcote rivers. We have documented procedures to electrically isolate our network in areas affected to protect our network components before they are significantly damaged. Our head office, including our control room, is not at significant risk from flood.

3.7.4 Cyber security breach

All businesses are now potentially susceptible to cyber-attacks from any part of the globe.

The security of our systems is vital to our ability to deliver a safe, reliable, resilient and sustainable service. We have two key categories of information systems risk:

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

We reduce the likelihood and potential impact of catastrophic failure of our information systems through a combination of procedures and technologies, including:

- robust systems procurement and maintenance – hardware and software
- rigorous change management
- good practice for regular and ongoing data and system back-ups and archiving
- highly resilient facilities
- robust security – computer network and physical
- key hardware and systems mirroring between physically separate sites
- active cyber security penetration testing. Customers benefit from safe online services, rigorous protection of their personal information and the 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 at server, network and device levels. We aim to employ fit-for-purpose and up-to-date security systems that track and respond to suspicious patterns of behaviour, known digital signatures and explicit security breaches.

We regularly update and train our people on cyber security and we seek their vigilant and active support for a secure information systems environment.

We 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.

3.7.5 Pandemic and variants

COVID-19 brought the risk of a pandemic into sharp focus. As an essential service provider Orion is acutely conscious of our responsibility to maintain vital power services to our community throughout this pandemic. As the situation evolved, our appreciation of the risks of pandemics on our ability to maintain our service to the community grew.

Skilled people are critical to Orion's ability to operate, manage and maintain the electricity network safely. There is a risk of our people contracting COVID-19 and the need to limit any spread throughout our workforce. We have taken significant steps to ensure the safety and wellbeing of our employees, and especially those who worked in critical control centre and customer support roles, as well as our operators in the field.

COVID-19 is impacting on our costs and supply chain, in particular on manufacturing and time frames for shipping. To manage this risk, we have increased supplier orders and carry extra supplies of essential items, as well as ordering equipment with extended lead time to ensure it is with us when needed.

Throughout all COVID-19 Alert levels, Orion continues to operate a safe and reliable network, and provide reassurance to the community that there was no heightened risk to the supply of power. While the future remains uncertain, we continue to monitor the situation in New Zealand and overseas closely and use what we have learned to adapt to the evolving situation.

3.7.6 Major network asset failures

3.7.6.1 Lifelines interdependencies

All lifelines utilities depend on electricity – so we plan and act for resilience accordingly. We also plan for when other lifelines services may not be available to us – for example, mobile and landline phone networks.

3.7 Our key operational risks continued

The New Zealand Lifelines Council has recently assessed and rated lifeline utilities interdependencies during/after HILP events, using a three-tier rating system:

3 – essential for the service to function

2 – important, but the service can partly function and/or has full back-up

1 – minimal requirement for the service to function

As shown Table 3.7.3, the Council rates electricity as 'essential' or 'important' for virtually all other lifelines utilities during/after HILP events. With a 'total dependency' score of 31, electricity has the fourth equal highest overall score.

Over the last few years, we have improved the resilience and reliability of our service to other key lifelines utilities, including to Lyttelton Port and Christchurch International Airport.

We also maintain a fleet of standby generators that can be repositioned at relatively short notice to key lifelines utilities in time of need – see a description of these in Section 7.19.

We are an active member of our region's Civil Defence lifelines group, and that engagement continues to inform our priorities to effectively address the interdependencies that relate to our service.

3.7.6.2 Grid exit points (GXPs)

Asset failure at either of our two key GXPs at Bromley or Islington, or our own network equipment at those sites, could be caused by liquefaction. At Bromley, ground settlement of 20mm to 40mm is possible, but this is unlikely at Islington. We rate this risk as low to medium.

We have recently implemented several improvements to the spur assets we have purchased from Transpower at Bromley and we will continue to implement improvements over the next few years. Transpower has also implemented improvements at our GXPs, pursuant to new investment agreements with us. In FY19, we purchased 33kV spur assets at the Islington GXP and we have upgraded our equipment and converted the arrangement there to an indoor switch room.

Our 66kV sub-transmission 'Northern Loop', commissioned in June 2016, has created a more interconnected sub-transmission system which significantly reduces our risks to GXPs. This AMP also details planned capex projects to further improve the interconnected nature of our sub-transmission system.

3.7.6.3 Zone substations

Zone substation failures across our network could be caused by liquefaction or asset failure. This could result in local outages of up to one day for several thousand customers. For most of our 50 zone substations, we rate this event as a low to medium risk.

Since 1995, we have assessed and seismically strengthened our zone substations as appropriate, following detailed engineering studies. In the 2011 earthquake, we had two severely damaged urban zone substations and we subsequently:

- replaced Brighton zone sub on better ground 1.5km away at Rawhiti
- rebuilt Lancaster zone sub on the same site to be more resilient

Table 3.7.3 NZ Lifelines Council interdependency ratings during/after HILP events – 2020

The degree to which the utilities listed to the right are dependent on the utilities listed below	Roads	Rail	Sea Transport	Air Transport	Water Supply	Wastewater	Stormwater	Electricity	Gas	Fuel Supply	Broadcasting	VHF Radio	Telecomms	**Total Dependency**
Fuel	3	3	3	3	3	3	3	3	3		3	3	3	**36**
Roads		3	3	3	3	3	3	3	3	3	2	2	3	**34**
Telecomms	3	2	2	2	3	3	3	3	3	2	2	3		**31**
Electricity	2	2	3	3	3	3	2		2	2	3	3	3	**31**
VHF Radio	2	2	3	3	2	2	2	2	2	2	2		2	**26**
Broadcasting	2	2	2	2	2	2	2	2	2	2		2	2	**24**
Air Transport	2	1	1		2	2	2	2	2	2	2	2	2	**22**
Water Supply	1	1	1	2		3	1	1	1	1	1	1	2	**16**
Stormwater	2	1	1	2	1	1		1	1	1	1	1	1	**14**
Wastewater	1	1	1	2	1		1	1	1	1	1	1	1	**13**
Rail	1		1	1	1	1	1	1	1	1	1	1	1	**12**
Sea Transport	1	1		1	1	1	1	2	1	1	1	1	1	**13**
Gas	1	1	1	1	1	1	1	1		1	1	1	1	**12**

We also have:

- targeted high voltage interconnectivity and diversity of supply
- contingency switching plans
- oil containment bunds at key sites
- simple and low-cost hold-down ties for transformers
- service providers who can cease planned work at short notice to respond to network incidents

3.7.6.4 Subtransmission overhead lines – 66kV and 33kV

Our overhead lines are widely dispersed and they are relatively easily repaired in an earthquake event. In the 2011 Canterbury earthquake, although there was damage to certain components for example, insulators, there was relatively little damage to our overhead lines when compared to an extreme weather event.

Our overhead lines in rural areas are exposed to extreme weather events. Subject to the ability of our repair teams being able to access the affected areas, they are relatively easy and quick to repair, but there may be outages of up to three days in some remote areas of our network. We rate this event as a relatively low to medium risk.

We have rigorous engineering standards and systematic inspection processes in place for our overhead lines and towers. Also, we have an active vegetation management programme which aims to minimise the impacts of trees on our overhead lines, particularly during storm events.

3.7.6.5 66kV oil filled cables

We have 40km of oil-filled 66kV underground cables left in the urban area, and have a project to replace these with more easily repaired cables in the event of a major earthquake. A major Alpine Fault earthquake could damage these cables, resulting in extended outages for significant numbers of our customers of up to seven days or more.

We rate this event as a medium to high risk over the next 50 years. We plan to replace these cables with modern and resilient XLPE cable over the next 10 to 15 years.

For management of asset related risk, see Section 5.6.2.

3.7.7 Other risks

In Section 6 we identify where the load at risk exceeds our security standard and the mitigation we propose. Here we discuss two risks that are often raised, but which we rate as relatively low risk for our network.

3.7.7.1 Environmental risks

We take practical steps to prevent undue harm to the environment. Our environmental sustainability policy states our aim to be environmentally and socially responsible in our operations, and in support of this we maintain an environmental risk register.

Our environmental management system covers the sustainable use of natural resources, reduction and safe disposal of waste, the wise use of energy, restoring the environment following works, commitment of appropriate resources, stakeholder consultation, assessment, and annual audit. Our job specifications for our key service providers include requirements to identify and manage environmental risks in the work they do for us.

We aim to reduce electrical losses on our network. We do this via our efficient network delivery pricing that signals system winter peaks – high loadings increase electrical losses – and via our network load management systems, especially our hot water cylinder control systems. It makes good environmental sense to reduce winter system peaks – in order to reduce electrical losses and to reduce the amount of investment in network necessary to deliver electricity.

We have over the years invested to reduce the risks of ground contamination from oil-filled transformers. Our main substation transformers have now been fully bunded to contain any spill and we have fully documented management procedures and the necessary equipment to deal with any minor spills from smaller transformers – for example, those that are pole mounted in rural areas.

Most of our 66kV circuit breakers use sulphur hexafluoride gas (SF_6) as the interruption medium. We have not found a viable alternative for this voltage. Our environmental management procedure for SF_6 gas aims to ensure we achieve our target of < 0.8% loss.

We also require our key service providers to adhere to the discovery and handling protocols for:

- asbestos
- hazardous substances
- items of archaeological significance, complying with Heritage New Zealand Pouhere Taonga Act 2014

We have rigorous engineering standards and systematic inspection processes in place for our overhead lines and towers.

We take practical steps to prevent undue harm to the environment.

3.7.7.2 New technologies

New technologies have the potential to transform how our network operates and enable our community to thrive in a low carbon future. We manage any risk associated with them, by planning for their introduction as much as possible, so they can be integrated into a wider 'energy ecosystem' and used in the most effective way. Examples include:

- Increased use of electric vehicles in the region will increase demand for electricity, but also introduce a fleet of batteries that could enable innovative load management techniques
- conversion of industrial heat processes from fossil fuels to low carbon energy, including electricity could also increase demand on our network, but also provide an opportunity to think about our energy system more widely and introduce a balanced approach to demand
- battery technology and energy management systems can improve the resilience of our customers and enable demand to be managed in a more nuanced way
- distributed generation, such as solar PV – this will potentially create more complex two-way flows between our network and end-use customers. We need to ensure our network can enable this to occur and facilitate the efficient and effective use and distribution of local generation wherever possible

Our risk management approach is to:

- keep up to date with technologies as they emerge
- assess the potential impacts and opportunities for our network
- understand more about our low voltage network – as this is where most two-way electrical flows will occur
- adhere to our business purpose and strategy – which is to be an 'enabler' for our customers

We are confident we can adapt our network to accommodate changing customer needs and preferences, and adopt new technologies that ensure our network is future-ready.

We are confident we can adapt our network to accommodate changing customer needs and preferences, and adopt new technologies that ensure our network is future-ready.

3.8 Our resilience

3.8.1 Introduction

Clause 14 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 (IDD) asks us to disclose:

- areas of our network that are vulnerable to HILP events
- our strategies and processes to identify and address those vulnerabilities
- our emergency and response plans
- our overall resilience

We define resilience as our ability to withstand, respond to and recover from significant, especially HILP, events.

As a lifelines utility, resilience is fundamental to our ability to provide a sustainable and fit-for-purpose service for the long- term benefit of our customers and our community.

We approach our network resilience from two main perspectives – we aim to:

- identify and reduce the impacts of future credible HILP events by how we design, construct and operate our network
- have a fit-for-purpose response and recovery capability

3.8.2 Our key network vulnerabilities

The lifelines interdependencies section, Section 3.7.6.1, describes the HILP vulnerabilities for our key network asset categories and our risk treatments and plans for them. For the purposes of this summary, our two significant vulnerabilities are:

- our outstanding risk treatments for spur assets we have purchased from Transpower since 2012. We have invested to substantially improve the safety, resilience and reliability of these assets since 2012 – and we plan to complete that investment programme over the next few years so that the spur assets meet our standards
- our remaining 40km of oil-filled 66kV underground cables. We plan to replace these cables with modern resilient XLPE cables over the next ten to fifteen years

3.8.3 Our conclusions on our resilience

There is no single measure of resilience. Assessing an EDB's resilience requires a good understanding of the key quantitative and qualitative aspects of the appropriate context and where an EDB is at in relation to that context.

Our resilience is the result of all that we do to:

- reduce the potential impacts of future HILP events – for example, we have strengthened our key substations and we have prudently invested to create a more resilient urban 66kV network
- be ready to respond and recover – for example, we have prudent operating practices for our people and service providers, we have prudent levels of key network spares, we learn and improve from our experiences of quakes, storms and other significant events, and we foster a culture that encourages our people to identify and assess relevant context and risks – and we act as reasonably practicable to treat our resilience risks

Overall, we believe we are achieving network resilience levels that are fit-for-purpose for our key lifelines responsibilities, in our local context and in the long-term interests of our customers and community. However, we can always improve and this AMP describes many of our initiatives that aim to do just that.

Overall, we believe we are achieving network resilience levels that are fit-for-purpose for our key lifelines responsibilities, in our local context and in the long-term interests of our customers and community.

3.8 Our resilience continued

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

Table 3.8.1 Orion's 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..
Security of supply standard	This standard, see Section 6.4.1 of this AMP, 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.
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 Communications 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.

4 Customer experience

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

Contents

4.1 Introduction

Orion works hard to understand the needs of our customers, and give them a voice in our decision making, as we power a vibrant and energised region now and into the future.

Being close to our customers is central to our asset investment decisions and asset management practices. We seek their views on a wide range of topics reflecting the Orion Group Strategy and our approach to the management of our assets.

To find out what our customers expect of us, and where they would like us to invest to support their vision for the future, we use a range of different methods of engagement to seek diverse views and cross-check what we are hearing.

In setting our service level targets we believe we have achieved the right balance between legislative, regulatory and stakeholder requirements, and what our customers expect.

This section outlines how we engage with our customers to understand their needs and what they expect from us in terms of service levels. It discusses how we measure our performance, our performance targets and how our network performs against those targets. Our SOI contains specific service level targets for reliability and other aspects of our business, some of which are outside the scope of this AMP.

Orion works hard to understand the needs of our customers, and give them a voice in our decision making.

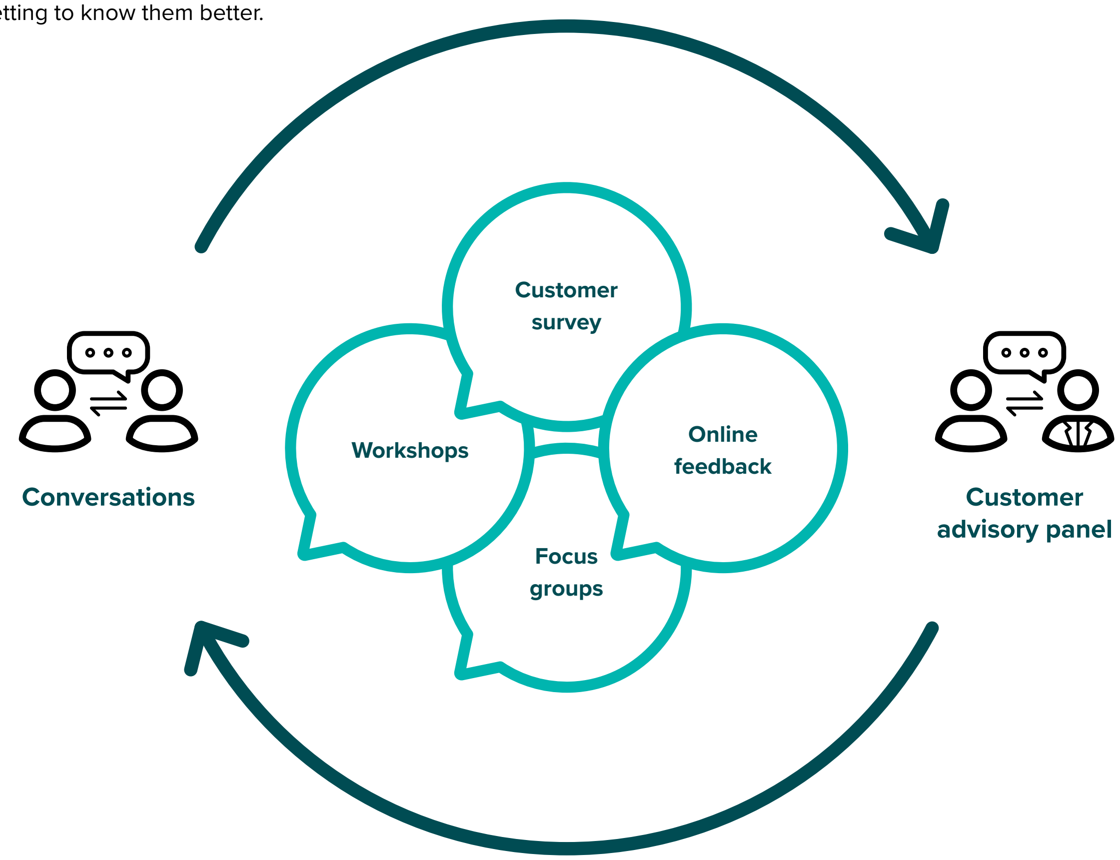
4.2 Customer engagement

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.



4.2 Customer engagement continued

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

Our customers want more control over where their energy comes from, and how they consume it. Customers are looking for flexibility, more choice and opportunities to help New Zealand's efforts to decarbonise.

It's 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 4.2.1 Our customer engagement helps Orion to:

4.2.1 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. Customers benefit from having their perspective represented in decisions about future investment and service enhancements.

4.2.2 Customer satisfaction research

Orion commissions an annual customer satisfaction survey carried out by independent researchers to measure the levels of satisfaction with our service, customers' views on our network reliability, their level of trust in Orion, and opinions on a variety of topical matters.

This is a robust survey of 800 urban and rural residential customers in our region. In 2021, we reviewed our survey methodology and revised it to include online participants to ensure we reached a broader demographic that reflected a more representative sample of our community. Periodically, we extend the survey to include small to medium business customers.

Because we survey a significant number of people across our region, we are able to 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.

From time to time we commission Focus Groups to provide deeper insight into customer's thinking on issues such as pricing options, specific network investments or our communications.

For the past three years we have also commissioned an annual follow-up survey of callers to our Customer Support team, to measure the level of customer satisfaction with our response to their enquiries.

4.2.3 "Powerful Conversations" workshops

We are exploring online alternatives to our face to face "Powerful Conversations" workshops which have not been possible under COVID-19 safety provisions.

4.2.4 "Always-on" Customer Support team

Our 24/7 Customer Support Team talks with our customers on a daily basis about the service they receive. Through emails and more than 2,000 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.

4.2.5 Major customer engagement

All of our major customers are invited to seminars where we take the opportunity to engage with them on key matters. These are people who run intensive power dependent businesses, from schools, supermarkets and malls to dairy processing plants and printing businesses.

4.2.6 Key stakeholder engagement

We regularly meet with key stakeholders and key influencers in the business community, our shareholders, Community Boards and local MPs to seek their views on our performance, future direction, and options we are considering.

In 2021 we conducted a materiality assessment with our key stakeholders to identify and prioritise material issues for the Orion Group. On our behalf, sustainability services company thinkstep-anz interviewed representatives of our key stakeholder groups to develop a shortlist of the issues of most importance to stakeholders. These insights will be considered in our asset management planning and reporting in the Orion Group's FY22 Annual Report.

4.2.7 Customer engagement over major projects

We have responded to increasing community expectations for more extensive communications about major projects affecting their service.

Where major projects have a significant impact on the community, we provide enhanced levels of communication directly with our customers and key community stakeholders. This can include 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, run local advertising and provide information via community social media channels.

4.2.8 Media, sponsorship and promotional events

Media releases, 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, such as encouraging businesses to consider adding electric vehicles to their fleets through our "EV Experience" partnership with the Canterbury Employers' Chamber of Commerce
- Displays at trade shows for the farming and general community

4.2.9 Advertising

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

- 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

We also use advertising to provide the public with information and reassurance during crisis events, such as the COVID-19 pandemic.

4.2.10 Website

Our website provides up to date information, real-time details of power outages and online customer service functionality.

We have enhanced the information provided on our power outages page to provide customers with updates on the cause of outages, and our progress with restoration.

4.3 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, in research and Panel discussions 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.

4.3 What our customers have told us continued

4.3.1 Customer satisfaction research results

We gather a wealth of information on what our customers think of our service. In our annual customer surveys, they rate us highly on key service metrics including our Net Promoter Score, and our Customer Support team's handling of their calls. As a reflection of our customer service and network performance, there is a high level of community trust in Orion. In 2021, we revised the methodology of our Annual Residential Customer Satisfaction survey to include online participants to ensure we reached a broader demographic that reflected a more representative sample of our community.

Figure 4.3.1 shows the key results from our latest customer research surveys.

Figure 4.3.1 Key results from our Annual Residential Customer Satisfaction survey, 2021; and Customer Calls research, 2021

Orion's overall performance

NPS +36
Orion's Net Promoter Score

8.1 AVG.
0—10 scale

38%
of respondents rate performance as a **10** on a 0—10 scale

Key perceptions of Orion

78%
agree **Orion is capable and effective**

76%
agree **Orion carries out its duties very well**

75%
agree **Orion maintains the electricity network well**

70%
agree **when the power goes out, Orion gets on to fixing it quickly**

61%
agree **Orion acts in the interest of local residents**

39%
agree **Orion takes their customers' views into account in its decisions**

45%
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

34%
Awareness of Orion

92%
Satisfied with reliability of power supply

84%
Level of trust in Orion

42%
Aware of the Orion website

30%
Aware of the Orion Customer Support service

100%
Had a good experience calling our Customer Support team

4.3.2 Communications

Our customers have also 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, and they make greater use of Orion's Customer Support team, and website.

4.3.3 Safe, reliable, resilient network

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

- **That our network can be safely accessed 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 reliable service is an abiding theme.** Customers view reliability as a "hygiene factor" and tell us that focusing on providing a reliable service should be fundamental for Orion. They want us to continue to invest to maintain our standard of reliability, although not at any cost. 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 5 November 2021 annual survey of residential customers found 92% were satisfied with the reliability of their power supply. See Figure 4.3.1.
- **Resilience is very important to our customers.** 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.

4.3.4 Affordability and equity

In conversations with our Customer Advisory Panel they tell us many of our customers are struggling to pay their power bills. We are having ongoing discussions with our customers to better understand the issues of power poverty and equity and develop ways we may be able to help those in need.

4.3.5 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. And in the most important measure of the effectiveness of our public safety campaigning, there were no serious incidents of electrical harm to the public in our region in FY21.

4.3.6 Sustainability

As we move forward on our sustainability journey, we are looking at how we are aligned to the United Nations Sustainable Development Goals. In our "Powerful Conversations" workshops and interviews with other key stakeholders, we talked with people about what sustainability means for Orion and where they think we should focus our efforts. The goals we found resonated most strongly for our customers and stakeholders are:

- working towards more sustainable communities and cities
- providing affordable and clean energy
- acting on climate change
- fostering good health and wellbeing in our community
- being responsible in the consumption and production of our business

These goals have been embraced in our Group Strategy, see Section 2.4.

4.3.7 Capability

As our industry goes through an era of unprecedented change, so too must our capability adapt to meet changing needs.

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 4.3.1, among a range of strongly positive scores in our latest Customer Satisfaction survey, 78% agree that Orion is capable and effective in the management of our network, and 76% say we carry out our duties very well.

What surveyed customers are less sure of is whether we are prepared for the future. Customers tell us we need to be ahead of developments in the industry and ready to help customers and energy providers adapt to new ways of managing the community's power needs. They encourage us to develop the capability that will be needed.

4.3.8 Future networks

At both our "Powerful Conversations" workshops and Customer Advisory Panel sessions Orion has been encouraged to have a strong focus on the future – to make sure our network is ready for customers to take advantage of new technologies.

In our annual customer survey, we found customers are less confident in our 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. We acknowledge we must do more to be ready for a changing future and accept the need to improve this perception.

4.4 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 stakeholder's views on our core network services and future direction as our Group Strategy evolves.

What we heard	What we are doing
Customer service • Give us more information when the power goes out • Provide us with power that is affordable	• Added functionality to our website to give regular updates on restoration progress for outages • We now communicate proactively with customers before significant planned outages, including Transpower GEN notices • Critically assessing our projects for "value for money"
Safe, reliable, resilient system • Improve our reliability in Banks Peninsula • Are you prepared for future natural disasters?	• Installed capacity to connect generators to maintain Akaroa power service in emergencies, and when undertaking maintenance and upgrade work • Increasing communications about our network resilience projects • Replacing oil filled cables
Health & safety • Keep us safe, but not at any cost	• Revamped our public safety education campaigns for stronger messaging and use more effective, new channels • Collaboration with EBD colleagues on ENA's national tree trimming advertising campaign
Sustainability • Take action to address the climate emergency	• Published our report: *Climate Change Opportunities and Risks for Orion* • Orion has committed to achieving carbon neutrality for corporate emissions by June 2022
Capability • Be prepared for the future	• Established the Energy Academy to transform industry capability and development in New Zealand • Established a new integrated Orion Group leadership team with a dedicated focus on preparing for a changed energy future
Future network • Reassure us you're ready to support our future needs • Be ready for change	• Our Group Strategy has five strategic themes, one of which is: Re-imagining the Future Network • Low Voltage network monitoring underway • Established the Orion Energy Accelerator programme

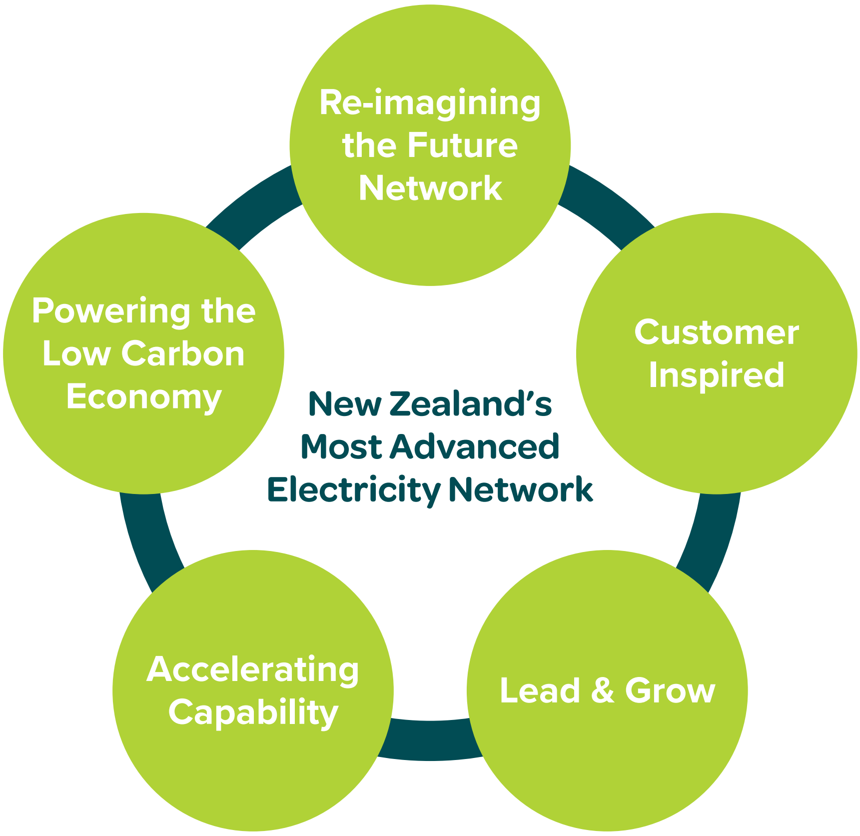
4.5 Performance measures

This section sets out how we measure our performance. We also report on our achievements against the targets we set ourselves as well as those set by our regulators.

Throughout our engagement with customers they have told us that a reliable supply of electricity is a top priority. This is a key service measure. We also monitor our performance against a range of other service measures including customer service, power quality, safety and environmental impact.

Table 4.5.1 shows our performance measures, our targets and how we have performed against them.

To ensure we maintain focus on achieving our Group Purpose, our performance measures are aligned to the Orion Group's Strategic Themes and our aspiration to be New Zealand's most advanced electricity network.



4.5 Performance measures continued

4.5.1 Performance against targets

Table 4.5.1 provides a summary of we have performed against our targets for the key measures related to management of our assets, customer service and environment. These targets are a sub-set of our overall Orion Group targets, set out in our SOI.

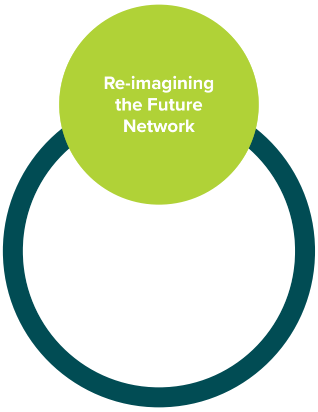
Table 4.5.1 Summary of performance against targets

Orion Group Strategic Theme	Service class	Measure	FY21 targets	FY21 performance	Achieved?	FY22-FY26 targets
Re-imagining the Future Network	Future network	% of transformers monitored across Orion's LV network	Not set	n/a	n/a	3%, 6%, 9%, 11.5%, 14.5%
Customer Inspired	Customer service	Time for a connection to be available: • Residential greenfield • Residential brownfield • Commercial	Measurement of provisional targets set proved problematic, and new targets are being developed	n/a	n/a	To be set to align with customer expectations
		Customer Support caller satisfaction	> 85%	95%	✓	> 85%
		Net Promoter Score	> 50	+36	✗	> 40*
Lead & Grow	Network reliability	SAIDI Unplanned	< 66.47	29.7	✓	Limit < 84.7
		SAIDI Planned	< 13.23	27.7	✗	5 year Limit < 198.81
		SAIFI Unplanned	< 0.86	0.5	✓	Limit < 1.03
		SAIFI Planned	Not set	0.09	n/a	No limit
	Network restoration	Unplanned interruptions restored within 3 hours	> 60%	75%	✓	> 60%
	Resiliency	Under development				
	Power quality	Steady state level of voltage	< 80	21	✓	< 60
		Level of harmonics or distortion	< 4	0	✓	< 4
	Safety	Safety of Orion Group employees	0 serious events	3 serious events	✗	≤ 4
		Safety of service providers	0 serious events	2 serious events	✗	≤ 4
		Safety of the public	0 serious events	0 serious events	✓	0
Accelerating Capability	Economic efficiency	Under development				
Powering the Low Carbon Economy	Environment	SF_6 gas lost	< 0.8% loss	0.32% loss	✓	< 0.8% loss
		Grams CO2e per MWh delivered – excludes distribution losses	Reduction towards 2030 target	219g – which is a reduction of 129g from FY20	✓	< 200g grams CO2e per MWh delivered

* Revised target reflects changes in survey methodology to canvas a broader demographic.

4.5 Performance measures continued

4.5.2 Re-imagining the Future Network

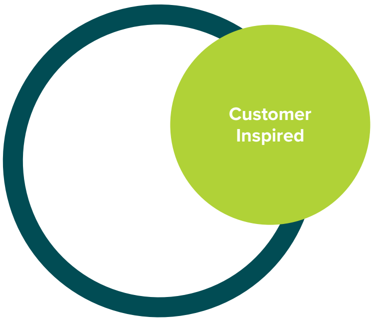


Our Low Voltage (LV) network will increasingly need to support new and more complex two-way power flows as customers progressively adopt alternative ways to power their homes, businesses and vehicles. We are installing new equipment in Christchurch residential areas that enables us to monitor the use of power in near real time, at street level. 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 6.2 for more information on our LV monitoring project.

Performance against targets

From our baseline of 210 monitors installed on our network in FY21, we have established targets reflecting approximately 3% growth per year in the number of transformers that will be monitored for FY22-FY26.

4.5.3 Customer Inspired



We established measures and targets for our performance in customer service for the first time in FY21. They measure and set ambitious targets for our performance in three key areas:

- **The length of time it takes us to connect a customer to our network** – following their request, and the provision of all necessary information. In FY21 we established provisional targets, however these proved problematic to measure and did not take into account customer expectations and what is most important to them.
- **Customer satisfaction with their calls to our Customer Support team** – more than 2,000 customers call our Customer Support team each month and it is important they come away from the experience with the information they need, and feeling positive about the experience. Independent researchers follow up with calls to customers who have recently contacted us, and seek their feedback.
- **Net Promoter Score** – we use an adapted version of a widely recognised metric that is traditionally used for retail organisations, which remains relevant in a regulated monopoly context. We believe that after their experience with Orion, our customers should be left feeling positive about us, with good word of mouth to their friends. With the New Zealand NPS rating for the power industry at +20 in FY21, our target reflects our goal to have loyal customers who rate Orion in the "GREAT" NPS range.

Performance against targets

For measurement of connections we are engaging with customers to establish what is important to them and developing our systems to better measure our performance in this area.

We exceeded our targets for customer satisfaction with calls to our Customer Support team, and our Net Promoter Score.

4.5.4 Lead & Grow

4.5.4.1 Network reliability

Network reliability is measured by the frequency and duration of interruptions to the supply of electricity to our customers. Our goal is to ensure that our reliability performance meets our regulatory requirements and our customers' expectations, established through the various means of consultation discussed in the previous section.

Our network reliability measures are as required by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012. These are:

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

SAIDI and SAIFI measures 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 by the Commerce Commission. Planned interruption limits are assessed over a 5-year timeframe, but unplanned interruption limits apply annually, which means that any year the unplanned limit is exceeded will result in a breach.

Performance against target

As shown in Figure 4.3.1, in our November 2021 annual survey of residential customers, 92% were satisfied with the reliability of their power supply.

The details of our performance in network reliability for FY21 are shown against our targets in Table 4.5.2. We achieved our network reliability performance targets for unplanned SAIDI and SAIFI. Our planned SAIDI target was exceeded, however this was still well within our regulatory breach limits.

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 4.5.1 and 4.5.2.

Table 4.5.2 Network reliability performance against target

Category	FY21 target – Planned	FY21 performance*	FY21-FY25 Limit
SAIDI – Planned	< 13.25	27.7	5 years of SAIDI< 198.1 (equivalent<39.7p.a.)
SAIDI – Unplanned	< 66.47	29.7	< 84.71 per annum
SAIFI – Planned	no target	0.09	no limit
SAIFI – Unplanned	< 0.8626	0.5	< 1.03 per annum

* Major event daily limits applied in accordance with CPP
# As per Commerce Commission disclosure schedule 10(v)

Figure 4.5.1 SAIDI 10 year history and 10 year target, including SAIDI forecast

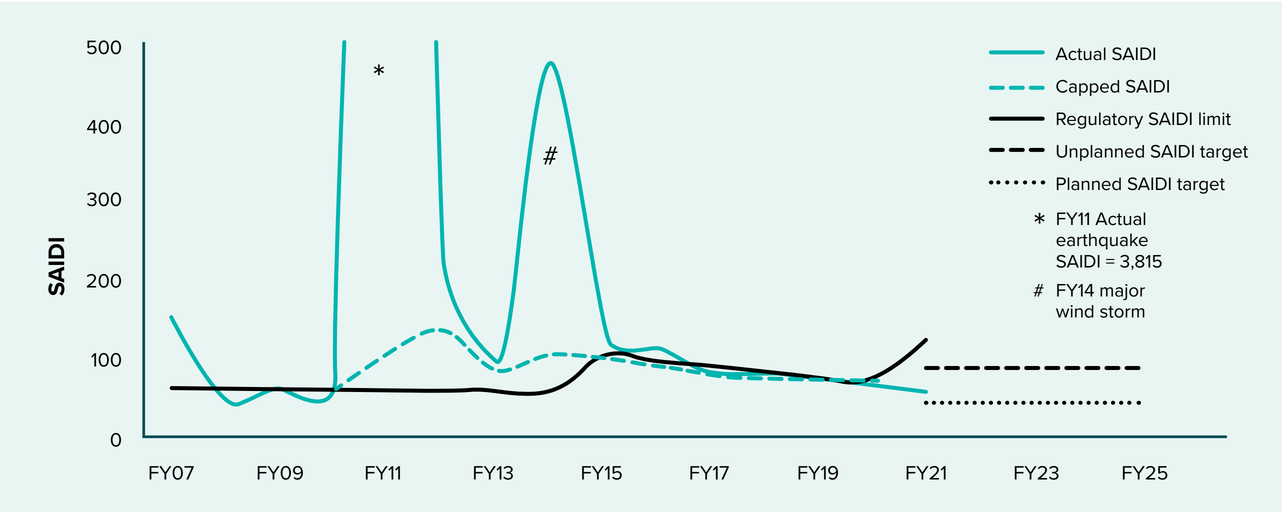
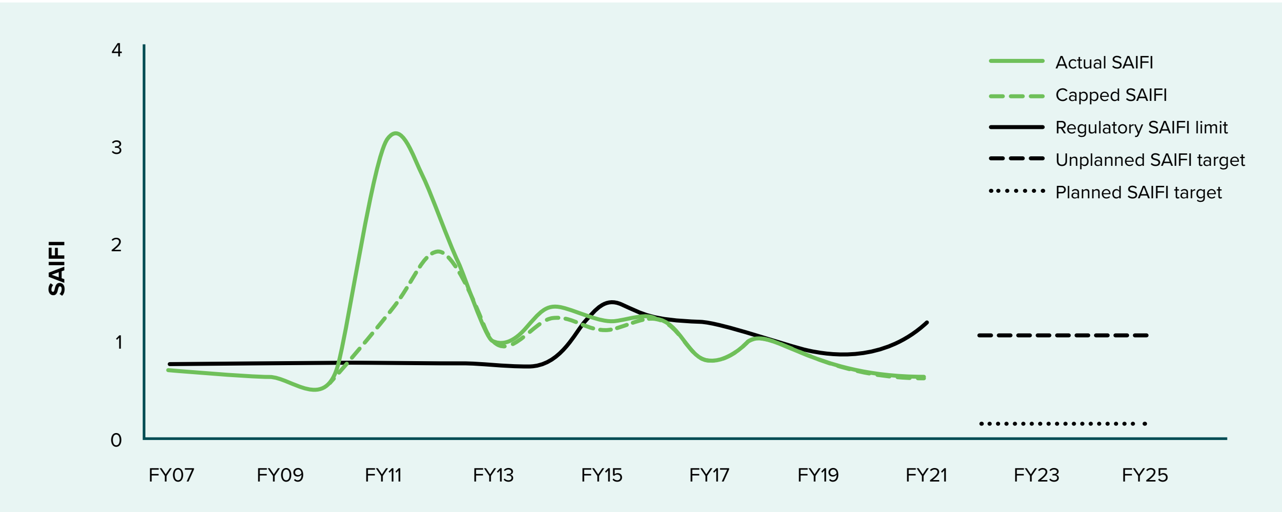


Figure 4.5.2 SAIFI 10 year history and 10 year target, including SAIFI forecast



Comparison by cause and asset class

Figures 4.5.3 and 4.5.4 show a further breakdown of SAIDI and SAIFI for FY21 compared to the five year averages by asset class and event cause. Our 11kV overhead network has always had the highest impact on reliability. The performance of secondary assets, such as communication and control systems, isn't specified as this is inherently captured in the service levels of the primary asset classes. These secondary assets have a latent impact on performance that is only observable through the flow on effects upon the performance of our primary assets. FY21 data of interest includes:

- There were no capped days for SAIDI or SAIFI
- Switchgear was the only asset category with SAIDI higher than the 5-year average
- Programmed outages have increased due to an increase in the number of scheduled works that required a planned outage. We have also seen our service providers opting for an outage instead of carrying out live line work which has also contributed to the increase
- The weather during FY21 was particularly benign, causing only 0.7 SAIDI

See Section 7 for the maintenance and refurbishment strategies needed to maintain performance.

Figure 4.5.3 SAIDI by asset class and by cause

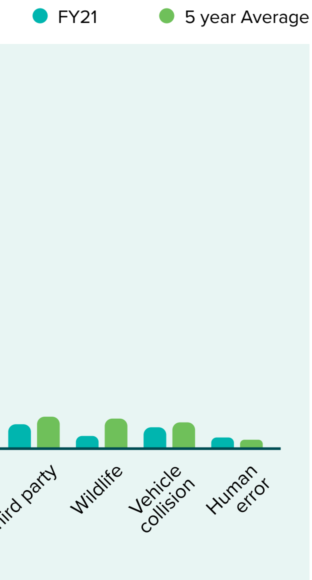
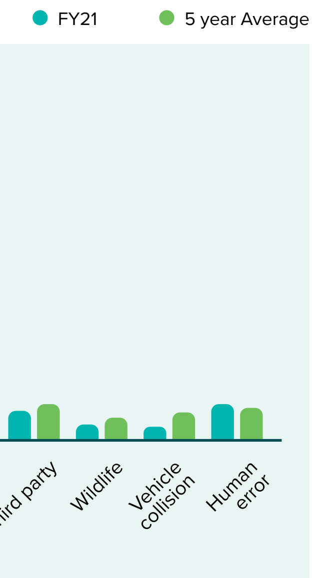


Figure 4.5.4 SAIFI by asset class and by cause



4.5 Performance measures continued

4.5.4.2 Network restoration

Our percentage of unplanned interruptions restored within three hours is based on providing a reasonable level of service at a reasonable cost. 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 affects 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 it can be seen in Figure 4.5.5, between FY10-FY14, we had a number of such events with earthquakes, snow storms and very high wind events which had an impact on the restoration times.

Performance against target

With improvements in fault indication 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 in Table 4.5.3 shows we achieved 75% restoration within three hours in FY21, well above our target of > 60% restoration within three hours.

Figure 4.5.5 Unplanned interruptions – % restored in under three hours

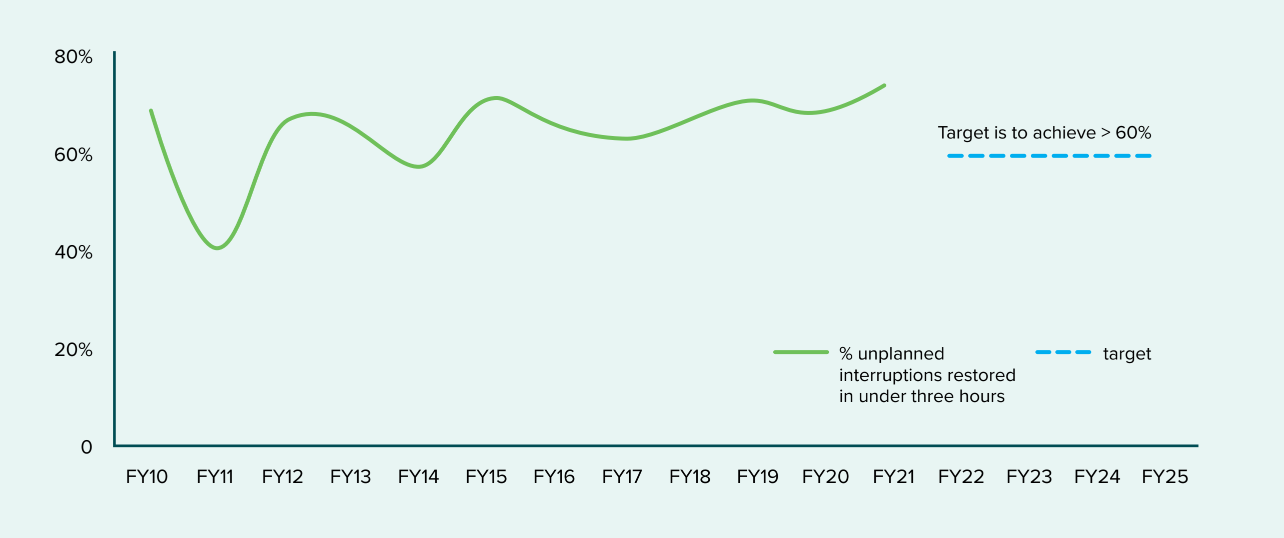


Table 4.5.3 Network restoration performance against target

Measure	FY21 Target	FY21 Performance	FY22-FY26 target
Network restoration	> 60%	75%	> 60%

4.5.4.3 Resiliency

Resilience is the ability of our network, our people and systems to respond to rare but major events such as earthquakes and wind and snow storms. Reliability is a measure of our day to day performance and is measured by the number and duration of power outages to customers. A more resilient network will limit the initial impact and be adaptable enough to reduce the time to recover from major events and will enable faster than otherwise restoration of power for those customers experiencing outages. We currently do not have a target or measure for resiliency. We will look to benchmark ourselves with the work Electricity Engineers' Association has conducted on the Asset Management Maturity Assessment Tool (AMMAT).

4.5.4.4 Power quality

Power quality is measured by a range of performance attributes. The two most common and important power quality attributes Orion can influence are:

- **the steady state level of voltage supplied to customers** – the range of steady state voltage supplied to customers is mandated by regulation at 230 volts ± 6%. We design and operate our network to meet this requirement. However, despite our efforts unanticipated changes in customer loads or unforeseen events result in some customers experiencing voltages outside these limits for short periods of time. This could affect customer's sensitive electronic equipment. We investigate any customer concerns about voltage fluctuations and if we find Orion is responsible, we will modify or upgrade our network to rectify the problem.
- **the level of harmonics or distortion of voltage of the power supply** – the allowable level of harmonics or distortion of the power supply provided to customers is also covered by regulation. 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 strength of the power supply at their premises.

An important aspect of maintaining quality of supply is to monitor power quality indices, and this is achieved by 33 permanently connected Dranetz power quality analysers. Our analysers monitor network voltages at 230V end of feeder, 400V start of feeder, 11kV and 66kV. A mix of parameters are measured which define the quality of voltage and current for regulatory levels.

Due to the wide range and type of power issues and the often limited customer understanding of complex technical information, communicating about power quality issues can be complicated. Our approach is to work with the customer's technical representative to gain a mutual understanding of the issues and discuss options for solutions. This results in a common understanding and transparent outcomes. In most cases customers don't require complex information, and simply need a resolution that balances benefits and cost.

Performance against target

Our main objective in relation to power quality is to identify and resolve customer quality of supply enquiries. To achieve this, we fit test instruments close to the point where ownership changes between Orion's network and the customer's electrical installation. Data gathered from the test instruments is analysed against the current New Zealand Electricity Regulations. By applying key regulations in relation to voltage, frequency, quality of supply and harmonics we can determine which quality problems have originated within our network. Our network performs well in terms of voltage and quality. We receive numerous voltage complaints every year but only around 20% of complaints are due to a problem in our network, predominantly relating to power outages. In Table 4.5.4, 'proven' means that the non- complying voltage or harmonic originated in our network.

We met our targets for FY21. Given our performance has been consistently below target for the number of proven voltage complaints, will review our target for FY22-FY26.

Table 4.5.4 Network power quality performance against target

Measure	FY21 Target	FY21 Performance	FY22-FY26 target
Voltage complaints (proven)	< 80	21	< 60
Harmonics (wave form) complaints (proven)	< 4	0	< 4

4.5 Performance measures continued

4.5.4.5 Safety

We are committed to collaboration across the Orion team to provide 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. Maintaining a safe and healthy working environment while working on and near our assets benefits everyone and is achieved through collaborative effort. Our target of no serious safety events or accidents is the only prudent target we could have to measure safety.

We report all employee injury and public safety events that are asset related via 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 investigations, enable us to provide staff and service providers with indicators of potential harm when working on and/or near our assets.

Performance against target

We had a total of five safety events in FY21 and therefore did not achieve our target of zero serious events. WorkSafe was notified of these events, which were:

- An Orion Group employee received a minor electric shock from a stay wire which was in contact with pole hardware (no injury)
- An Orion Group employee received an electric shock when a de-energised 11kV overhead line made contact with a live 33kV line (no injury)
- At an Orion Group worksite there was an uncontrolled crane truck movement which resulted in injuries to one Orion Group employee and a service provider's employee
- A service provider received a minor electric shock from a damaged cable while removing a temporary power supply cable from a distribution box (no injury)
- A service provider's helmet contacted an 11kV overhead line while tree trimming (no injury)

We have modified our future health and safety targets to four or less safety events per year as shown in Figure 4.5.6. We believe this is a more reasonable and realistic target based on the type of activity we carry out. 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 safety targets relating to assets are met in the future.

Figure 4.5.6 Safety performance – serious event trend and new targets

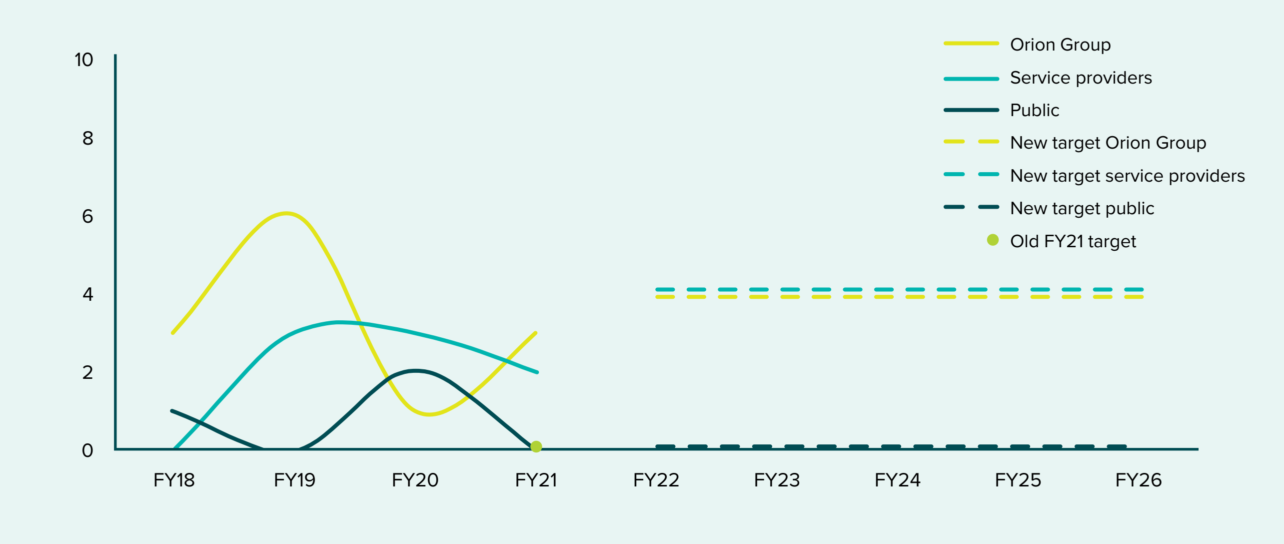


Table 4.5.5 Safety performance against target

Measure	FY21 Target	FY21 Performance	FY22-FY26 target
Safety of Orion Group employees	0 serious events	3 serious events	≤ 4
Safety of our service providers	0 serious events	2 serious events	≤ 4
Safety of public	0 serious events	0 serious events	0

4.5.5 Accelerating Capability

Capability underpins operational performance, sustainability and operational efficiency.

Our customers are very price conscious. They expect us to operate efficiently and keenly balance the cost impacts of maintaining and developing our network against the benefits to them as consumers. They expect Orion to focus on accelerating our capability to ensure we operate an efficient business that does all it can to provide an affordable energy service.

We are currently exploring new ways to measure our operational efficiency and productivity to ensure we are delivering the cost effective service customers need.

Traditionally, we have adopted the following measures of economic efficiency, and these were in place for FY21:

- capital expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per MWh of electricity supplied to customers
- operating expenditure per annum per year end number of ICPs (connection points)

There are inherent limitations when comparing our performance with that of other EDBs. Each EDB has its own local context, asset history, business purpose and drivers. For this reason the comparisons provided in Figures 4.5.7 and 4.5.8 are for guidance only.

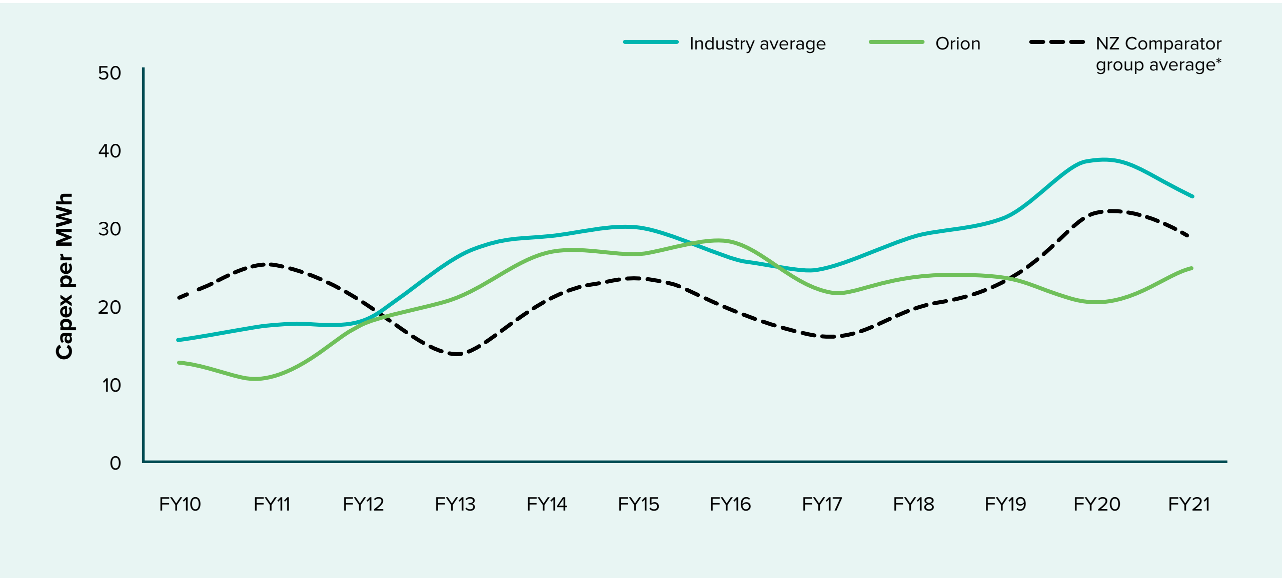
4.5.5.1 Capital expenditure per MWh

Figure 4.5.6 compares our performance for capex per MWh with both average industry performance and a subset NZ comparator grouping. The sharp increase in our capex expenditure immediately following the 2010 and 2011 Canterbury earthquakes through to around FY17 is clearly visible.

The industry average and the subset NZ comparator show an increasing trend of capital expenditure from FY17 while our expenditure leveled off. Projects to support the significant ongoing growth in customer numbers and component price increases meant in FY21 our capital expenditure moved into closer alignment with that of both the industry average and the subset NZ comparator grouping.

We are currently exploring new ways to measure our operational efficiency and productivity to ensure we are delivering the cost effective service customers need.

Figure 4.5.7 Comparing Capex per MWh and industry performance



* Wellington Electricity, WEL Network and Unison

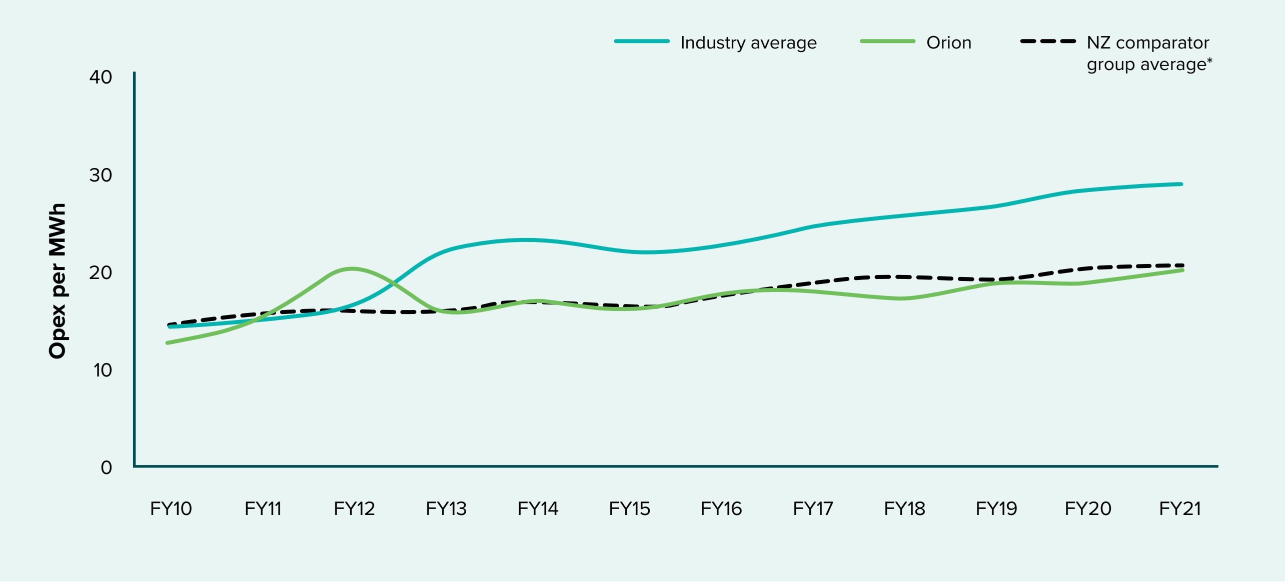
4.5.5.2 Operational expenditure per MWh

Figure 4.5.7 compares our performance for opex per MWh with both average industry performance and a subset comparator group.

A short term increase in our opex expenditure, combined with a reduction in consumption from impacted buildings immediately following the 2010 and 2011 Canterbury earthquakes, is clearly visible between FY11 and FY13. Despite this our operating expenditure remains substantially aligned with that of the industry average and strongly aligned with the subset NZ comparator grouping preceding FY13.

All three parameters show a gradual ramping up trend of operating expenditure from FY13. Our expenditure forecasts reflect this. We are moving into a period of asset management continual improvement linked closely to meeting customer needs. As a balance to this we ensure our evolving service provider workload is set at sustainable levels that match our resource availability.

Figure 4.5.8 Comparing Opex per MWh and industry performance



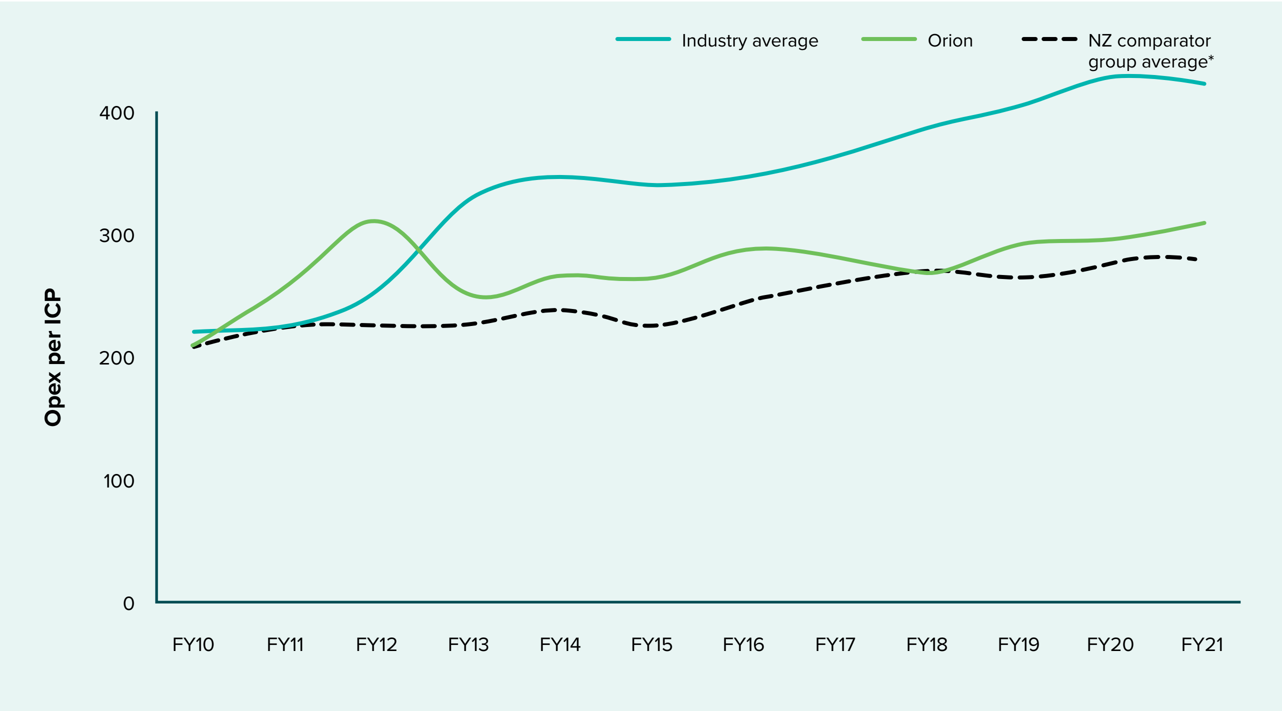
* Wellington Electricity, WEL Network and Unison

4.5.5.3 Operational expenditure per ICP

Figure 4.5.9 compares our performance for opex per ICP with both average industry performance and a subset NZ comparator grouping. A short term increase in our opex expenditure, combined with a reduction in connected ICPs immediately following the 2010 and 2011 Canterbury earthquakes, is clearly visible between FY10 and FY13. Despite this our operating expenditure follows a similar path, although at a slightly higher level due to the combination of ICP reconnection and decommissioning post-quake, with that of the subset NZ comparator grouping preceding FY13.

Overall we are proud of our performance and feedback from our customer engagement tells us we are meeting our customers' service expectations. We are focused on our Purpose to power a cleaner and brighter future for our community. The industry average follows a similar upward trend but at a notably higher average level possibly due to the inclusion of smaller EDBs with rural low density networks. All three parameters show a ramping-up trend from FY13. Our ICPs increased from 189,000 at the end of FY13 to 211,600 at the end of FY21, with a record 4,100 new ICPs in FY21. Our on-going increase in opex per ICP reflects the increased operational cost of servicing these new ICPs, and remains in step with the NZ comparator group.

Figure 4.5.9 Comparing Opex per ICP and industry performance



* Wellington Electricity, WEL Network and Unison

4.5.6 Powering the Low Carbon Economy

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 for our community.

Operational emissions

Orion has a strong focus on reducing our operational emissions, including those of our subsidiary, Connetics. Transport is a key contributer to our operational emissions.

Our vehicle fleet includes battery-powered electric vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEVs). We are trialling remote control of our EV chargers, to avoid charging them at the peak times when New Zealand's current energy mix relies heavily on coal. Through our EV Experience, in partnership with the Canterbury Employers' Chamber of Commerce, we are giving other businesses the opportunity to trial an EV as part of their vehicle fleet.

Biofuel trials

We use diesel generators to support customers during power outages. We have trialled 100% biodiesel alternative fuel made from used cooking oil. We are sharing information from our use of this low-emission fuel with our customers who also rely on diesel generation to maintain business operations. This reduces the perceived risk for them and helps encourage others to try alternative, low emission fuels in generators they may have for business resilience.

Management of SF_6

Orion uses sulphur hexafluoride (SF_6) in our network as an electrical insulator and arc suppressant in 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. Orion is also working to reduce the introduction of new SF_6 into the network, so we are trialling a vacuum insulated 66kV circuit breaker as part of Project 894.

Low carbon design

Reducing emissions isn't just about substituting carbon-reliant technology for a low-emissions alternative. For Orion it is also about designing our network to take advantage of technology that helps reduce our carbon emissions, and managing our supply chain.

We use new technologies such as drones and remote switching technology to reduce travel with its reliance on fossil fuels. We also design our network so equipment supply chains are short, or circular where possible. A well designed network is resilient and efficient, and we expect to see these measures reduce our operational costs, particularly as the cost of fossil fuels increases as forecast.

Lowering our embodied footprint

Innovative design is about optimizing the way our infrastructure operates and can be maintained, but also recognizes that the equipment we use carries an embodied financial and resource cost. If we are responsible and efficient in our design, this lowers our embodied footprint and should lead to long term cost savings.

We have a significant pole replacement programme scheduled over the next 10 years and commissioned a life cycle analysis of different pole options, to assess which type had the best environmental outcomes. This identified that our wooden poles sequester enough carbon during their growth to more than offset the carbon used in installation and maintenance. It also identified that reducing emissions on installation will increase the net negative emissions associated with using poles on our network.

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, below the regulated target of 1% of our actual losses.

Due to our reporting obligation to the Ministry for the Environment, our current target is measured as a percentage of SF_6 loss. We achieved our FY21 target for SF_6 loss and there were no uncontained oil spills recorded for the year.

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

Table 4.5.6 Sustainability performance against target

Measure	FY21 Target	FY21 Performance	FY22-FY26 target
SF_6 gas lost	< 0.8% loss	0.32% loss*	< 0.8% loss
Grams CO_2e per MWh delivered – excludes distribution losses	Reduction towards 2030 target	A reduction of 129g from FY20	< 200g grams CO_2e per MWh delivered

* Calendar year performance for 1 Jan 2020 to 1 December 2020

8,000

Square kilometres network coverage

11,600

Kilometres of lines and cables

50

Zone substations

400

Major customers with loads from 0.2MVA

90,000

Orion power poles

11,742

Distribution substations

5

About our network

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

Contents

5.1 Introduction

This section presents an overview of Orion's network architecture, the current design of our subtransmission network, our major customers' load and an overview of our assets. See Section 6 for details on how we plan development of our network and Section 7 for how we manage the lifecycle of our assets.

5.2 Transpower Grid Exit Points (GXP)

Our network is supplied from seven Transpower Grid Exit Points (GXP) at substations as shown in Table 5.2.1. The three remote GXPs at Coleridge, Arthur's Pass and Castle Hill each have a single transformer and a much lower throughput of energy.

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 relays. They are covered by an Access and Occupation Schedule Agreement with Transpower.

Transpower charges users, for example Orion and MainPower, for the costs of upgrading and maintaining GXPs. Orion owns all the assets connected to the 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 5.2.1 Customers by Grid Exit Point

GXP	Customers %
Islington	71%
Bromley	26%
Hororata	2%
Coleridge, Arthur's Pass, Castle Hill and Kimberley	1%

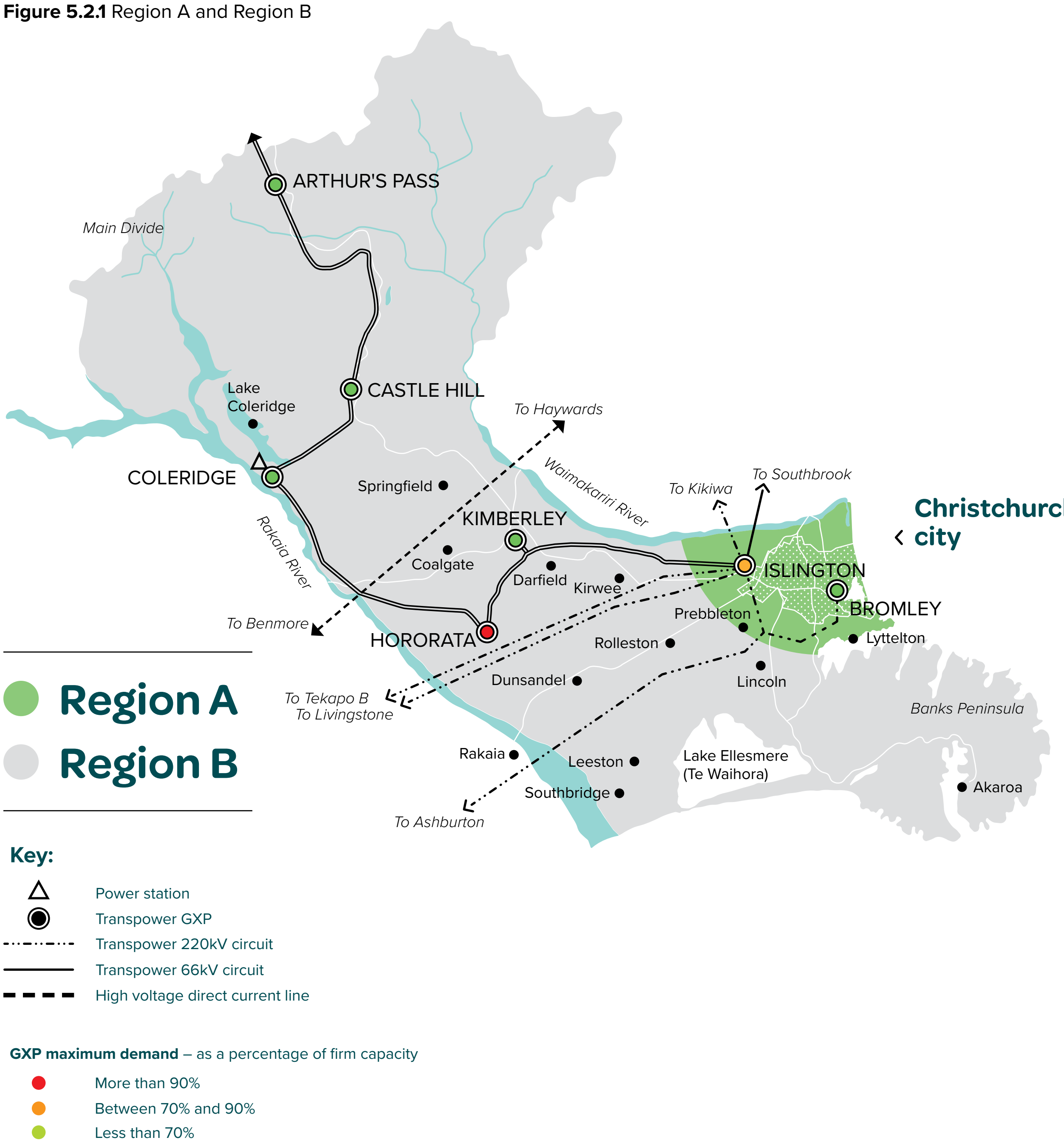
The Islington GXP supplies 71% of our customers. As the number of customers reliant on the Islington GXP grows, we are working with Transpower to overcome the risks associated with being highly dependent on one GXP by adding a new GXP at Norwood, near Dunsandel. Orion's network serves a diverse range of customers, spread over a variety of terrains with different challenges. For planning purposes, our network is divided into two regions:

Region A – Christchurch city and outer suburbs, including Prebbleton

Region B – Banks Peninsula, Selwyn district townships

Orion's network serves a diverse range of customers, spread over a variety of terrains with different challenges.

Figure 5.2.1 Region A and Region B



5.2.1 Region A GXPs

As shown in Figure 5.2.1 Region A GXPs are located at Islington and Bromley and supply the Central Business District, Lyttelton and the Christchurch city 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.

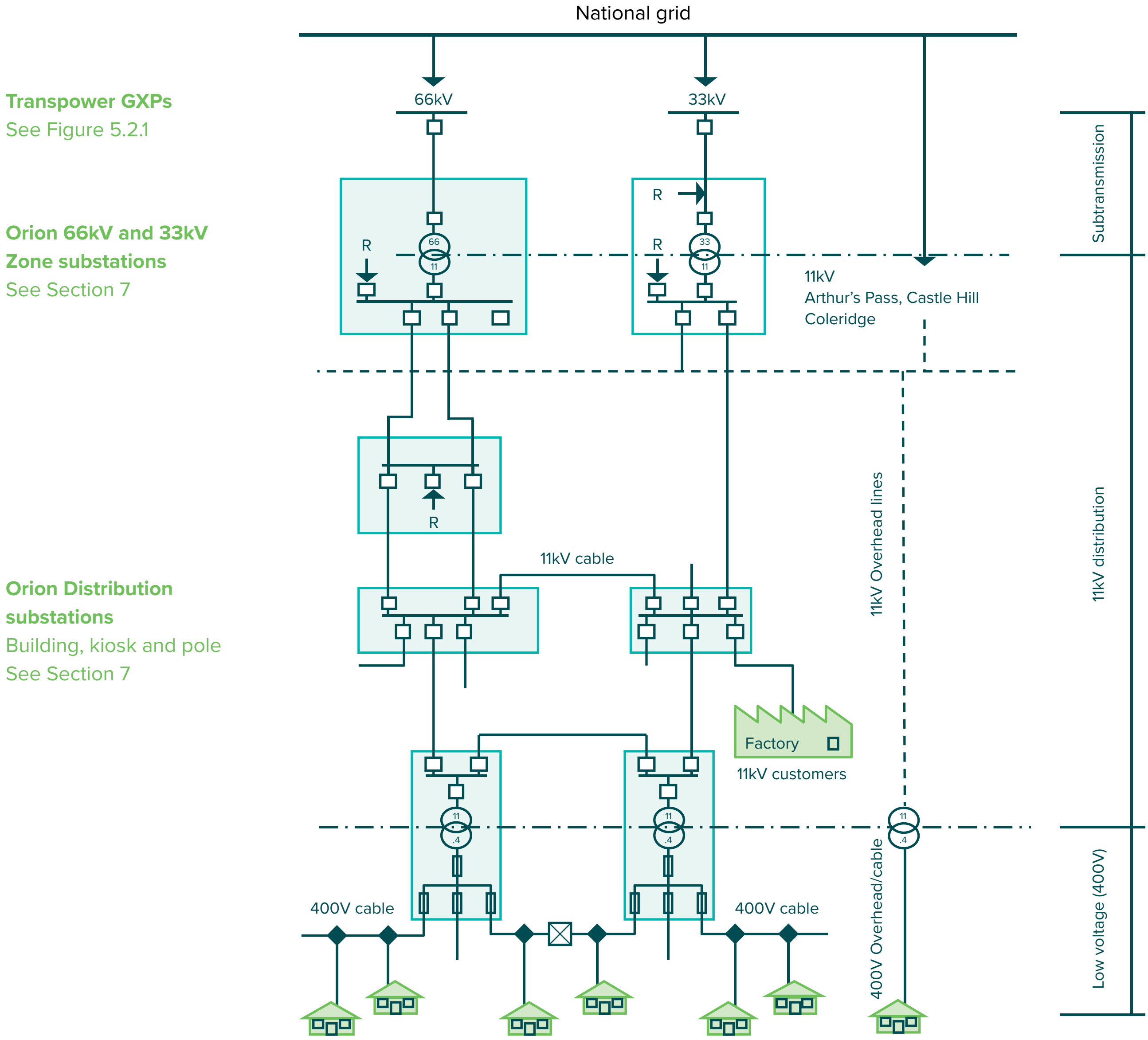
5.2.2 Region B GXPs

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. The remainder of Region B is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill. Together these supply less than 1% of our customers and load.

5.3 Network architecture

Approximately 83% of our customers are in Region A with the remaining 17% in Region B. Figure 5.3.1 shows an overview of our network architecture.

Figure 5.3.1 Network voltage level and asset relationships



Key:

Circuit breakers (see Section 7.10)

Major power transformer to 11kV (see Section 7.11)

Distribution transformer to 400V (see Section 7.12)

Ripple injection plant (see Section 7.17)

400V fuse switches (see Section 7.10)

Distribution cabinet (see Section 7.3)

Distribution box (see Section 7.3)

5.4 Major customers

Orion has approximately 400 customers who are categorised 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 to explore options to better manage their energy consumption, we work with them to meet their needs.

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.

Our delivery pricing structure for major customers gives them the ability to reduce costs by managing their load during peak network demand signal times during the period from 1 May to 31 August. This enables us to manage load during network maximum demand times.

Although there are issues to be co-ordinated when sites with generation are established, there is minimal impact on the operation and asset management of the local area network. See Section 6.4.5.1 for details of our Distributed Energy Resources management initiatives.

Our major customers operate across a range of industries and sectors as shown in Table 5.4.1.

Table 5.4.1 Major customers by load size

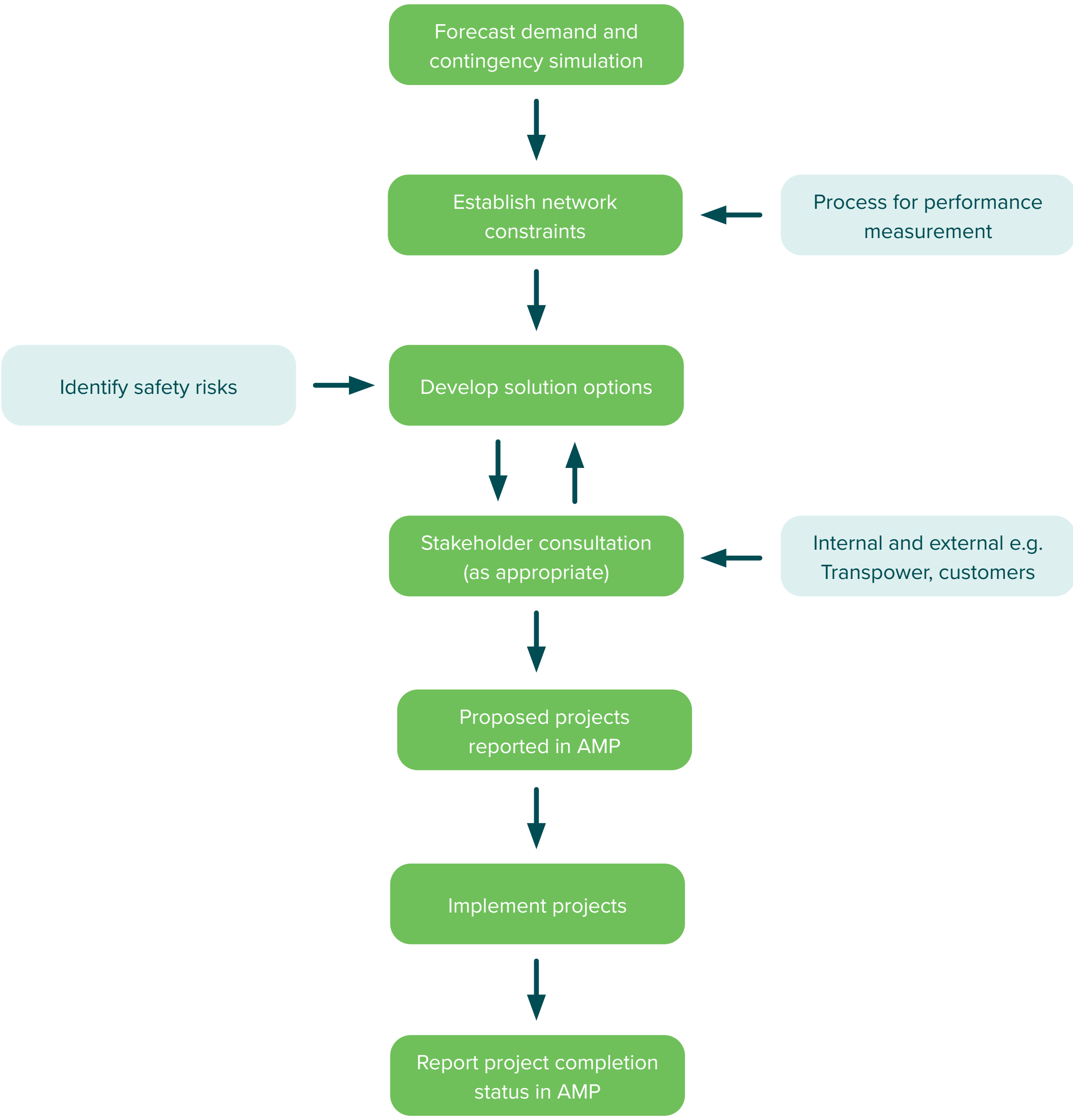
Load	Industry/Sector	Number	Notes
≤ 2MVA	All	~380	Includes heavy manufacturing, hotels, water and wastewater pumping stations, prisons, retail and businesses.
> 2MVA	Food processing	6	The Synlait Milk plant at Dunsandel was commissioned during 2008. It required a new zone substation at Dunsandel to provide enhanced security. In 2018 Orion worked with Synlait to support their installation of New Zealand's first large-scale electrode boiler as part of its strategy to significantly reduce its environmental impacts. The Darfield Fonterra plant commissioned during 2012 required a new zone substation (Kimberley).
	Tertiary Education	1	
	Shopping mall	2	
	Hospital	2	
	Airport/seaport	2	As part of 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	

5.5 Network development approach

We plan our network using a network development process which is informed by the needs of our customers. See Figure 5.5.1. It is based on the following criteria: our Security of Supply Standard, network utilisation, forecast demand compared with network capacity and non-network solutions. This process benefits our customers because it allows us to balance the growth needs of the community and new connections while ensuring appropriate levels of reliability and security for all customers. Further details on our approach to planning and specific planning criteria are set out in Section 6.4.

We plan our network using a network development process which is informed by the needs of our customers.

Figure 5.5.1 Process for network development



5.5 Network development approach continued

When a network issue is identified, for example a safety risk, capacity or security of supply gap, the process of developing solutions begins. We consider different options to address the gap which may include both network and non-network solutions including Distributed Energy Resources such as batteries. We also consider whether the solutions comply with our design standards including safety objectives, capacity adequacy, quality, reliability, security of supply and economic consequences. Further details of our network planning criteria are set out in Section 6.

Once we have established the way forward, we go through a project prioritisation process. There we look at how we can best schedule projects to fit in with NZ Transport Authority and local authority projects, meet customer expectations, consider service provider resource constraints and align with our asset replacement and maintenance programme.

Once we have established the way forward, we go through a project prioritisation process.

More detail on our project prioritisation process is described in Section 6.4.4.

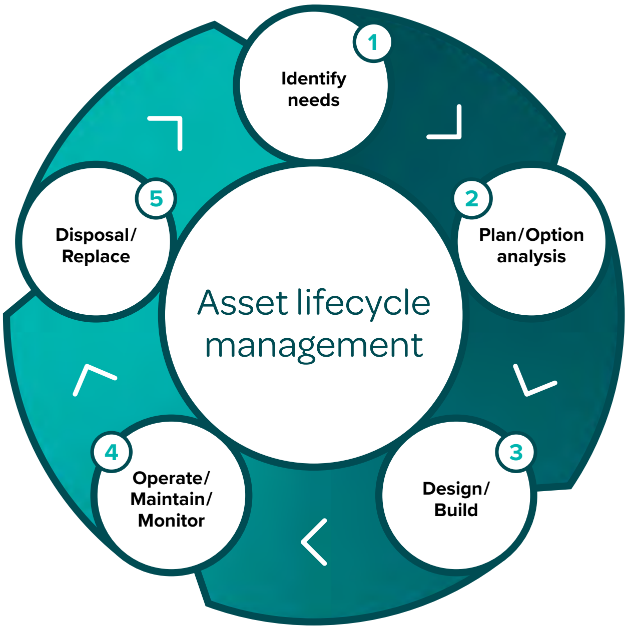
5.6 Asset lifecycle management approach

Our engagement with customers as described in Section 4 tells us that our customers want us to maintain a safe, reliable, and increasingly resilient network. We deliver this by managing our assets using an asset lifecycle management approach which includes asset maintenance planning using reliability centred maintenance and maintenance and risk management techniques. Throughout this process we balance our shareholder and customer needs today, and into the future. Asset lifecycle management means taking a long term view to make informed and sound investment decisions to deliver our service levels at an appropriate cost. Benefits of a whole of life approach are:

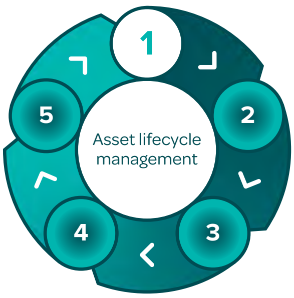
- minimising safety risks and future legacy issues through safety in design
- understanding capex/opex trade-offs
- establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- minimising the total cost of ownership while meeting accepted standards of performance

The steps we take through our lifecycle asset management approach are described in Figure 5.6.1.

Figure 5.6.1 Asset lifecycle management approach



5.6.1 Identify needs



The first step in the asset lifecycle management process is to establish customer needs and future network demands. We do this through customer engagement and customer satisfaction research.

We also take into account health and safety considerations 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 4.

5.6.2 Planning and options analysis

Based on what needs are identified, we then move into the planning stage. During this stage of the lifecycle process, we develop the replacement plan and the maintenance plan.

5.6.2.1 Replacement plan

A number of techniques are used to ensure assets are kept in service until their continued maintenance is uneconomic or until they have the potential to pose a health and safety, environmental or reliability risk. This is in accordance 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 5.6.1 provides a summary of the asset management approach for each asset category.

Our current approach is based around the following:

- high value assets or assets with a high consequence of failure – predominantly condition based replacement based on robust inspection, testing and failure rate
- other assets are age or condition based replacement as appropriate
- 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
- substation buildings and kiosks are maintained and repaired when required

Table 5.6.1 Asset management approach for asset class

Asset class (arranged in order of FY23 capex high to low)	Tool	Predominant condition based replacement		Predominant age based replacement	Run to non-operational	Indefinite maintenance and repair
	Approach	CBRM model	Asset condition & performance	Asset data	–	Asset data
HV Switchgear & circuit breaker		✓				
Overhead lines – 11kV		✓				
Distribution transformer					✓	
Power transformer & regulator		✓				
Protection		✓				
Overhead lines – 400V		✓				
Overhead lines – 33/66kV		✓				
Underground cables – 400V			✓			
Communication systems				✓		
Control systems				✓		
Substations						✓
Load management				✓		
Monitoring					✓	
Underground cables – Comms					✓	
Underground cables – 11kV			✓			
Underground cables – 66kV			✓			
Underground cables – 33kV			✓			

5.6 Asset lifecycle management approach continued

Condition Based Risk Management Model

We have Condition Based Risk Management (CBRM) models for the majority of our 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 determining the optimum balance between on-going renewal and capex forecasts.

The CBRM model is one of the tools used to inform our decision making for selected asset classes as part of building our asset replacement programmes. The CBRM models calculate the health index and probability of failure of each individual asset. It then takes into account the consequence of failure to finally assign the risk to that particular asset. Our health index scoring is different to the Commerce Commission grading system set out in Schedule 12a of the information disclosure requirements.

Figure 5.6.3 CBRM score conversion table

Probability of failure	Condition →	Health index →	Schedule 12a grade →	Definition
High	Poor	10+ (9–10) (8–9)	H1	Replacement recommended
		(7–8)	H2	End of life drivers for replacement present, high asset related risk
Medium	Fair	(6–7) (5–6) (4–5)	H3	End of life drivers for replacement present, increasing asset related risk
Low	Good	(3–4) (2–3)	H4	Asset serviceable. No drivers for replacement, normal in service deterioration
		(1–2) (0–1)	H5	As new condition. No drivers for replacement

5.6 Asset lifecycle management approach continued

Asset risk matrix

We have refined our approach to risk assessment for our portfolio assets by more explicitly showing health and criticality. As a result, we can now visually display through a risk matrix the level of risk attributed to each individual asset within an asset class and what intervention strategy is required. The risk matrix is used to identify which asset when replaced will provide the greatest reduction in the overall fleet risk profile.

As shown in Table 5.6.2, the inputs to the risk matrix are our **asset health index** and **asset criticality index**.

- **Asset criticality index** – evaluates how failure could have an impact on safety, network performance, financial and environment. As the consequences for the different categories are not the same, criticality weightings are applied to give a criticality score, ranging between C1 to C4 where C1 represents the most serious consequence
- **Asset health index** – ranges between H1 to H5 with H1 being the worst health. Asset health is calculated based on asset age and factors such as its installed environment and performance. The factors vary for different asset classes.

The resultant risk matrix provides a visual representation of risk for a fleet of assets and the risk grades are linked to the replacement strategy. The risk grade definitions for R1 to R5 are aligned to the EEA Asset Criticality Guide and our corporate risk guideline. See Section 7.6 for the application of the risk matrix for poles.

Table 5.6.2 Our risk treatment and escalation guidelines

Risk ratings	Definition		Strategy
R1	Extreme	Combination of high consequences of failure and reduced HI indicates high risk	Immediate intervention
R2	Very high	Combination of criticality and health indicates elevated risk	Schedule intervention
R3	High	Healthy but highly critical assets	Reduce consequence of failure
R4	Medium	Typical asset in useful life phrase	Monitor and maintain
R5	Low	Low relative consequence of failure	Tolerate increased failure rate

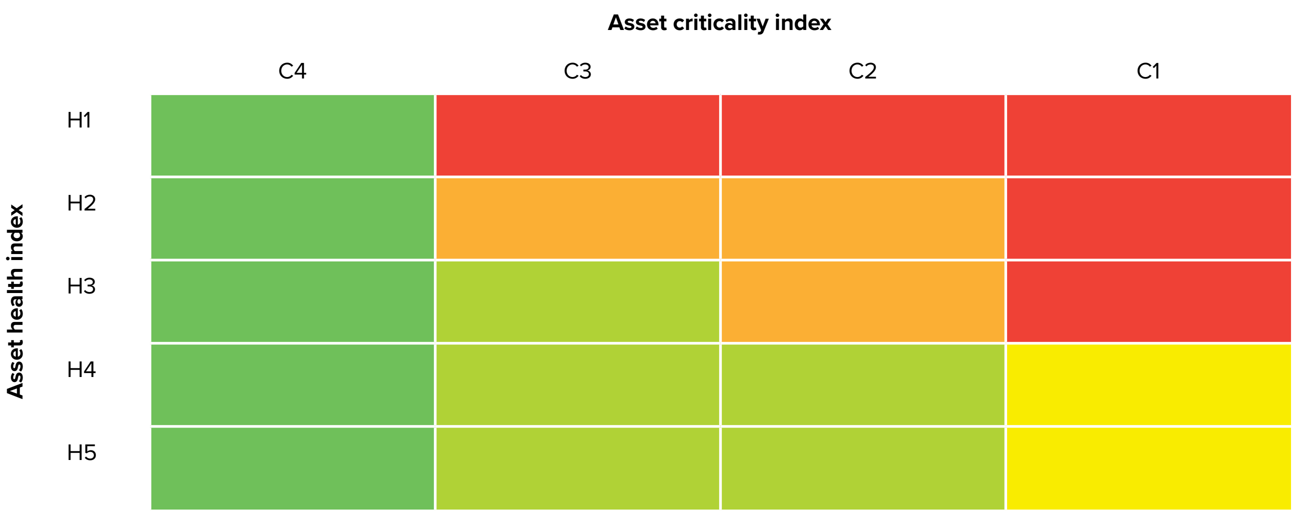
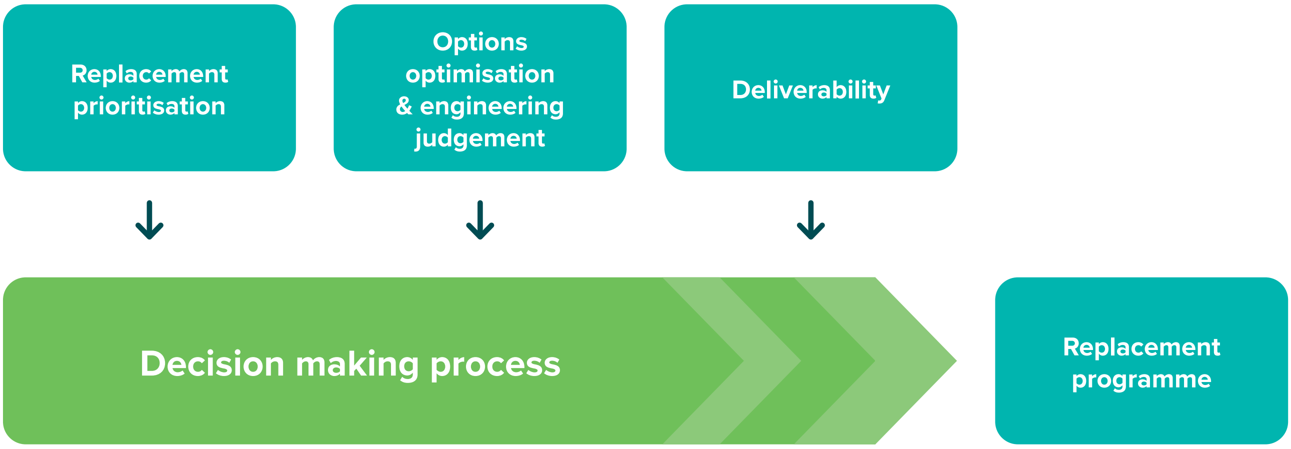


Figure 5.6.4 Replacement decision making process



Replacement prioritisation – is used to inform our decision making for selected asset classes as part of building our asset replacement programmes. This effectively gives the asset a ranking which can be used to help prioritise replacement strategies.

Options optimisation – one of the main options that we analyse for our asset replacement programme is around the timing of the replacement. This ensures that we are getting the best usage of our existing asset. The CBRM model can aid us in this process by creating scenarios, including 'doing nothing', that model the deterioration of asset condition giving us an indication of the additional risk that is imposed allowing us to then decide if this is acceptable and if this significantly affects our service levels.

When an asset is identified for replacement it is seldom a simple matter of replacing like for like. Internal review, analysis and planning are undertaken for the asset, its interaction with other equipment and its integration into the immediate network. This leads to a range of options to continually improve our asset, network operation, service levels and reduce overall cost. The options involve consideration of the following:

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

Deliverability – analysis is undertaken to determine if the work plan can be delivered. It should be noted that external influences could adversely or positively impact the delivery outcome. The number of units to be replaced can be affected by network constraints, resourcing issues and the overflow of uncompleted work from previous financial years. The objective is to smooth the works programme by deferring where we can but also by bringing replacement forward where appropriate. For more information on deliverability see Section 10.

5.6.2.2 Maintenance plan

Our network maintenance philosophy is reliability-centred and based on retaining a safe asset function. The majority of our assets are subjected to a routine time based programme of inspections, maintenance and testing. However, for our high value assets with high consequence of failure we also undertake a reliability based programme where the frequency and activities are tailored according to the performance and condition of each asset. This is considered a cost effective option for this type of asset as replacement is very costly, however maintaining reliability is critical as an asset failure has a high impact on service levels and other objectives. The detailed asset management activity of each asset class and the equipment within the asset class are described in the relevant sections of this AMP and also in our associated internal Asset Management Reports.

We have specific maintenance programmes for each of our asset classes however all works generally fall into the following categories:

- **Scheduled maintenance** – work carried out to a predetermined schedule and allocated budget
- **Non-scheduled maintenance** – work that must be performed outside the predetermined schedule, but does not constitute emergency work
- **Emergency maintenance** – work that must be carried out on a portion of the network that requires immediate repair

5.6.3 Design and build

We use service providers for the design and build of projects identified in the AMP. Through this process, we use a number of key standards and specifications that are set out below.

5.6.3.1 Safety in Design

We have developed a Safety in Design process that can be applied at any stage of asset lifecycle and can also be applied to non-network assets such as vehicles, tools and innovation. The Safety in Design standard is used by us and approved service providers to identify hazards that could exist throughout the complete lifecycle of assets from concept to disposal via construction, operation and maintenance. The standard includes a hazard identification and risk assessment process which, when applied by designers and other key participants such as those who construct and operate the assets, proposes elimination and control measures for each identified hazard to a level so far as is reasonably practicable. The Safety in Design process aligns with industry best practice and ensures designers carry out their duties in line with the Health and Safety at Work Act 2015.

This innovation delivers on two areas of focus in our asset management strategy:

- continually improving to provide a safe, reliable, resilient system
- maintaining our health and safety focus

Customers benefit as a result of the equipment we install being designed in a way that protects public safety, minimises customer outages and enhances system resilience in adverse events.

5.6.3.2 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 approved service providers. Normally we only accept designs that conform to these standards, however this does not limit innovation. Design proposals that differ from the standard are considered if they offer significant economic, environmental and operational advantages. Design standards are listed in Appendix D against the asset group they relate to.

5.6.3.3 Technical specifications

Technical specifications are intended for authorised service providers working on the construction and maintenance of our network and refer to the relevant codes of practice and industry standards as appropriate. Specifications are listed in Appendix D against the asset group they relate to.

5.6.3.4 Equipment specifications

We also seek to standardise equipment used to construct components of our network. To this end 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.

New equipment types are reviewed to carefully establish any benefits they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where possible.

5.6.3.5 Equipment operating instructions

To ensure the wide variety of 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. We create a new operating instruction each time any new equipment type is introduced. See Figure 5.6.5 – Process to introduce new equipment.

5.6.3.6 Operating standards

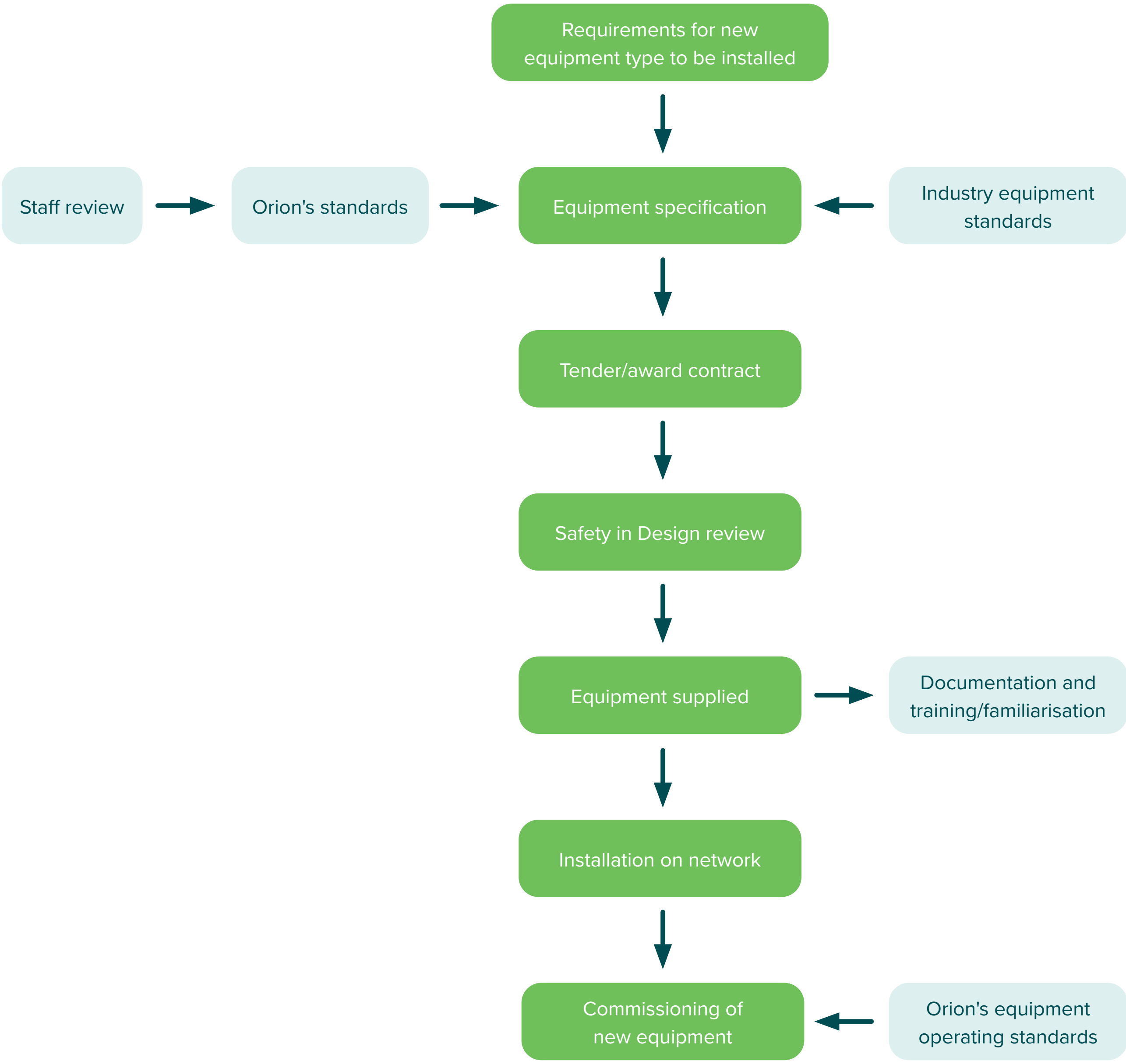
To ensure our network is operated safely we have developed standards that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access permit control.

5.6.3.7 Document control process

To ensure our documentation and drawings are maintained as accurately as possible, each is 'owned' by one person who is responsible for any modifications to it. Our Asset Information team is responsible for processing these controlled documents using a process set out in our document control standard. This standard also defines a numbering convention used to identify our documents based on the type and assets covered. This approach assists in searches for relevant documents.

Email and a restricted-access area on our website are used to make documents and drawings accessible to approved service providers and designers.

Figure 5.6.5 Process to introduce new equipment

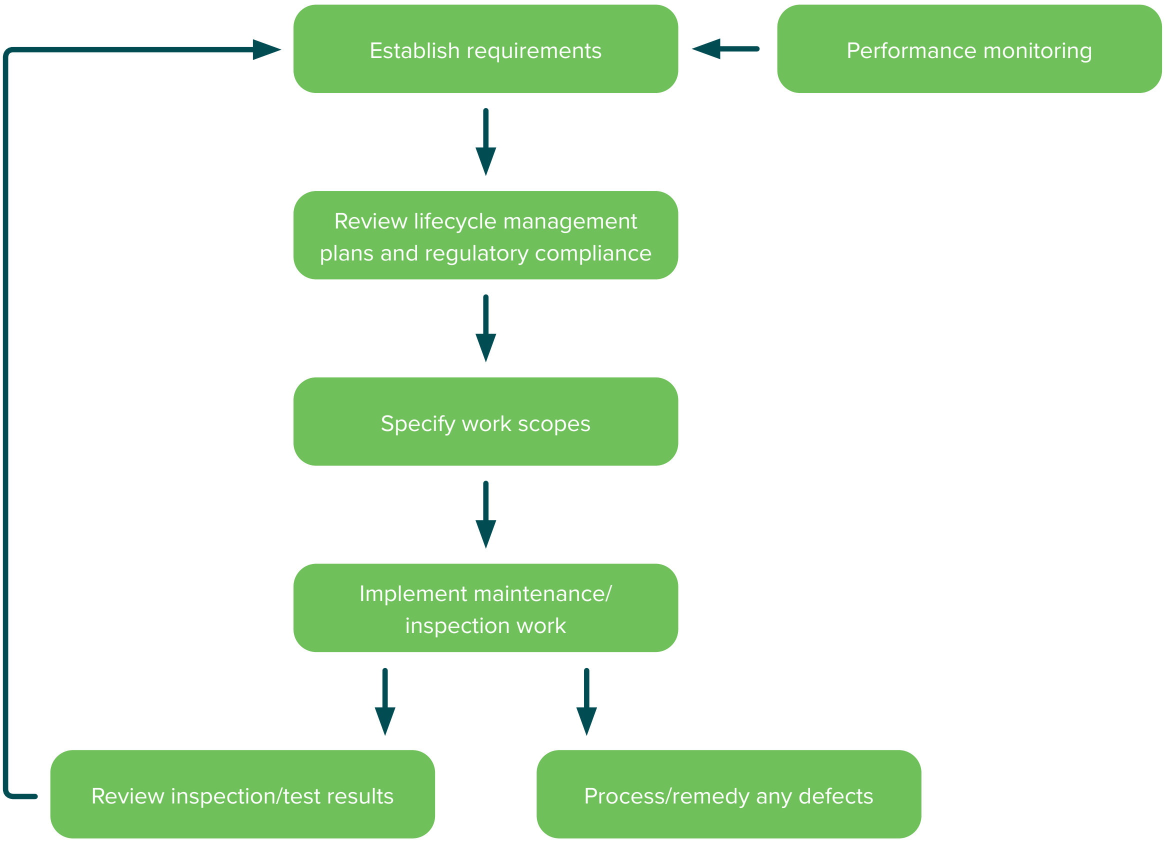


5.6.4 Operate, maintain, monitor

The operate, maintain, monitor phase of the lifecycle is in accordance with our maintenance plan. Each asset class is subject to a specific regime for routine inspection and maintenance and also specified asset replacement programmes.

Requirements and scopes of work are developed from these plans in-house and we then use our contract delivery framework to contract out works, see Section 10. Monitoring of assets is against the service levels defined in this AMP, but also against specific requirements of the asset class. The process is shown in Figure 5.6.6.

Figure 5.6.6 Process for routine asset inspection and maintenance



5.6.5 Disposal and replacement

Disposal and replacement 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, requirements and scopes of work are developed in-house and then go through a competitive tender process to contract out the works.

We are committed to being environmentally responsible and we dispose of our assets in an environmentally 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.

5.7 Investment and business case framework

We develop business cases for near term projects with different options for solving system issues and meeting customer need. Business cases support our network development and complex lifecycle management capital projects, and Asset Management Reports (AMRs) support our lifecycle management portfolio programmes of work. Business cases are often underpinned by an overarching business case which addresses our security of supply architecture standards.

Our infrastructure team and other relevant support people along with our leadership team provide internal peer review and challenge to these business cases and AMRs. We also share our thinking and a selection of business cases with our leadership team and board where they meet defined investment thresholds for approvals under our investment and business case framework.

Further detail about the areas we consider in our network development approach and our planning criteria can be found in Sections 5.5 and 6.4; and the asset lifecycle management approach is explained in Section 5.6. Orion uses an asset planning decision framework and options assessment approach to decide the complexity of a business case based on the network project type proposed. Table 5.7.1 provides a summary of the assessment level decision framework.

Table 5.7.1 Assessment level decision table

	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, replacement / reinforcement	Weighing up options to improve reliability, resilience, future network, replacement / 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

Planning our network

Photo: View of Christchurch and wider region taken from the Port Hills.

Contents

6.1 Introduction

In this section we set out how we plan our network to prepare for the future. We discuss the changing demands on our infrastructure as we respond to the growing needs of our region, and the challenges and opportunities posed by an era of rapid change in our industry.

Towards the end of this section we detail the proposed projects our planning process has identified are needed to maintain and increase the safety, reliability, resilience and sustainability of our network over the coming ten years.

Our capital expenditure keeps pace with the growing demand on our network. This growth is both in terms of the number of customers we serve, and energy demand.

We continue to experience steady growth in the number of residential customers moving into new housing developments in the Selwyn District and Halswell area. In Christchurch inner suburbs where Christchurch City Council has changed zoning, we have also experienced a significant increase in in-fill housing.

For example, at present the population of Rolleston sits at around 20,000 and is predicted to jump to 28,000 within a decade. Growth in industrial parks also continues as businesses take advantage of new energy efficient premises with easy access to road and rail.

To support this growth, we have planned significant projects. Some examples of these are:

- a new Region B GXP at Norwood to support growth in Selwyn District and western Christchurch
- a new Region B zone substation near Rolleston to support load growth in Rolleston and shift load from Islington GXP to Norwood GXP
- an upgrade of the Halswell zone substation capacity to support residential load growth in the southwest of Christchurch
- a programme of LV network reinforcements in areas where we forecast constraint

At Orion, we are committed to powering a cleaner and brighter future for our community. Key to this is ensuring our customers can take advantage of new low-carbon technologies and providing them with greater freedom to manage their energy use to achieve their decarbonisation goals.

We will continue to lead and encourage our customers to adopt low-carbon technology, particularly for process-heating, and transportation where the biggest reduction in carbon emissions can be achieved. We aim to provide a safe, reliable open-access network where customers can connect any compliant load, storage or generating device and use our network as a platform for services to other connected customers.

At Orion, we are committed to powering a cleaner and brighter future for our community.

In addition to this, we are seeing increased interest in new types of Distributed Energy Resources (DERs) such as solar panels, wind-turbines, battery storage and electric vehicles. DERs are technologies that can generate or store energy at a customer or utility-scale energy level. They challenge the traditional approach to network operation and planning which assumes larger centralised power supplies which feed one-way to our customers. In contrast, DERs can change power flows from single to multi-directional which places additional demands on our low voltage networks which were not originally designed for this type of operation.

To meet these challenges, we are implementing initiatives that increase our knowledge of the network and systems that can fully utilise the data sources at our disposal to optimise the planning and operation of our network. This will enable us to distribute clean, reliable and affordable power for the benefit of our customers and our region through our open-access network.

6.2 Evolving our network

The existing electricity business model is largely uni-directional. Large generators sell their production in the wholesale market, and the electricity is then distributed to end user customers, via the transmission network and lines companies such as Orion. This traditional one-way model is undergoing change for several reasons. These include:

- **Distributed Energy Resources (DER)** – 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
- **utility-scale alternative energy generation** – the development of commercially operated wind and solar farms will change the energy landscape
- **advanced digital technology** – will enable greater information access and management options at household and business levels
- **new consumption patterns** – adoption of EVs, other low carbon initiatives and other new technologies will create new challenges due to their increased demand for energy with less predictable behaviour

With these developments, and others that will emerge, our customers may increasingly wish to:

- sell surplus power to the grid
- store own-produced electricity for their future consumption and cost savings
- sell power on a peer-to-peer (P2P) basis to others
- develop virtual storage in neighbourhood networks
- charge their electric vehicles, and other flexible usage devices, at times when electricity pricing is lowest
- ramp back power usage at times when New Zealand's generation is operating from non-renewable sources

Customers will have many choices for investment and how to make the best use of the options open to them. We will continue to develop our understanding of what our customers want from us and how this translates to services they need. Regardless of the direction our customers and the market take, we will invest in new systems and technologies to deliver future customer benefits over our AMP planning period.

We will continue to develop our understanding of what our customers want from us and how this translates to services they need.

6.2.1 Developing our LV capability

Historically, LV networks were planned for reasonably stable passive household loads with one-way power flow. However, more customers are adopting technologies such as EVs which can place significant additional demand on a street's LV system. Given Orion's LV networks supply most of our residential customers, developing the visibility and capability of these networks is becoming increasingly important to efficiently manage our networks and facilitate customer choice.

We have four LV initiatives currently ongoing:

- LV monitoring
- Smart meter information gathering
- LV usage scenario research
- LV network reinforcement, when identified as necessary

These initiatives will develop our LV networks and help us to:

- provide information to guide our operational, planning and investment activities
- develop improved forecasting and modelling techniques for the future
- 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 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, enabling others to participate in developing solutions

6.2.1.1 LV monitoring

In FY20, we began a 10 year programme to install monitoring at around 35% of our distribution transformers. These sites, in Christchurch residential areas, were prioritised based on a wide range of criteria such as those with high customer numbers and a number of solar connections, were long overhead feeders, as well as those which were included in our existing renewal programmes. To verify our prioritisation process, we commissioned high-level constraint modelling of our LV network by the Electric Power Engineering Centre (EPECentre) at the University of Canterbury. Based on the results of that modelling, we have revised our programme to target a smaller group of high-risk sites and have accelerated the programme for completion in FY26. In FY21, we installed 210 LV monitors covering 16,000 customer connections.

LV monitoring enables us to observe the use of power in near real time, at street level. This low voltage monitoring will 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 to provide customers with a more flexible, dynamic range of choices for managing their energy needs.

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.

In the long-term, we aim to use this data to monitor trends and demand profiles at the LV feeder level to inform our investment decisions.

In the UK, 70% of solar penetration at household level occurs on just 30% of UK streets. This clustering effect is one of the reasons we need to increase our visibility and understanding of our low voltage network to ensure we focus network development on the areas where it is most needed.

We can also leverage our LV monitoring programme to gain greater visibility of our HV network by using the live LV monitor data in conjunction with the state-estimation capabilities of our Advanced Distribution Management System (ADMS).

With increasing rates of installation, we expect to achieve our target of 1,600 sites by the end of the programme in FY26.

6.2.1.2 Smart meter information gathering

While the 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.

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.

To monitor performance of this aspect of our service, we'll 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.

We are currently working with meter providers to obtain access to smart meter information and are hopeful this is achievable. This data will help us prioritise where we should install real-time monitoring. An allowance for sourcing additional smart meter information has been incorporated in our operational expenditure.

In the long-term, we aim to use this data to monitor trends and demand profiles at the LV feeder level to inform our investment decisions.

6.2.1.3 LV usage scenario research

In FY20, we commissioned a high-level deterministic study, in collaboration with EPECentre at the University of Canterbury, to forecast the potential impact of electric vehicles and residential batteries on our low voltage network. The study focussed on residential areas which were more likely to experience residential infill and EV clustering. This study built on the preliminary constraint results published in our 2019 AMP by refining our network parameters and investigating a wider range of EV charging behaviours.

The four scenarios considered were:

- **Scenario 1** – Diversified EV load at peak (1kW/EV)
- **Scenario 2** – Undiversified EV load at 9pm (3kW/EV)
- **Scenario 3** – Diversified EV load at peak with battery support (1kW/EV and 4kW battery support from 5% of connections)
- **Scenario 4** – Undiversified EV load at peak (3kW/EV)

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 have enabled us to identify LV networks which will be most vulnerable to load changes arising from the adoption of EVs and residential batteries. Figures 6.2.1 and 6.2.2 summarise our findings, based on our four scenarios. These results clearly illustrate the benefits of diversified charging behaviour to spread load more evenly over the network in the long-term.

Lower off-peak pricing can lead to deferred charging behaviour resulting in higher undiversified loads. Scenario 2 demonstrates how off-peak pricing to encourage deferring charging until after 9pm shows some merit at low EV penetrations rates but causes greater constraints on the network as the EV population grows.

Figure 6.2.1 Projected residential distribution transformer constraints

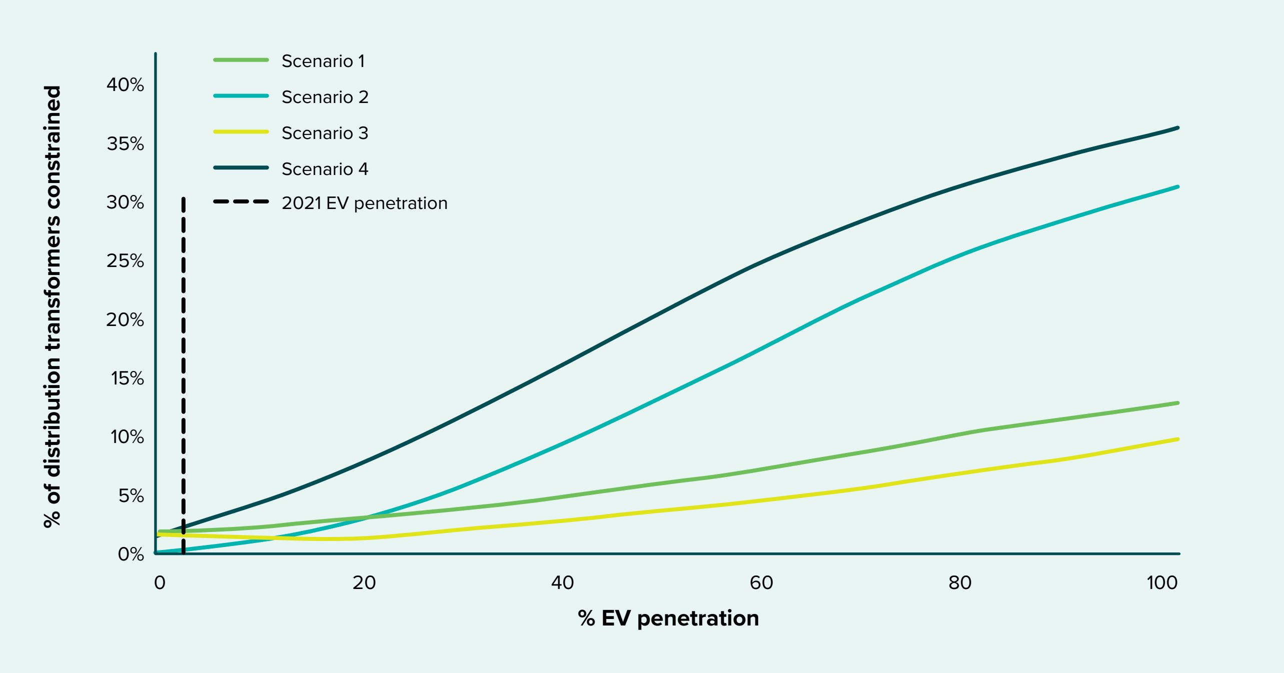
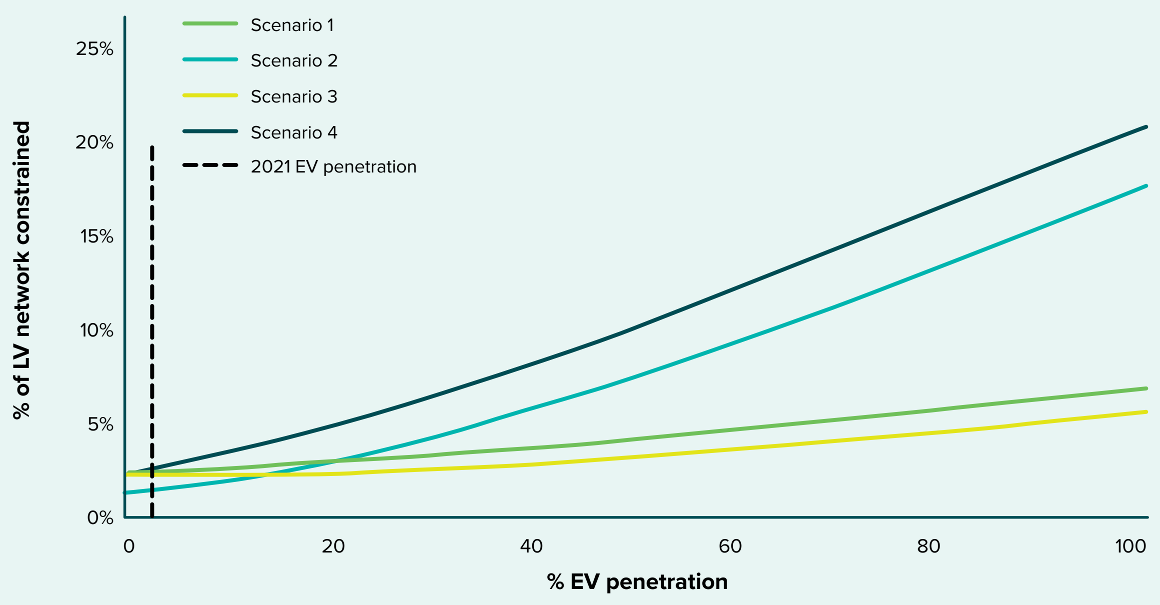


Figure 6.2.2 Projected residential LV network constraints



EV uptake in our region is currently estimated at around 2.6% of our customer connections. However, due to the clustering effect, it is unlikely that these are evenly distributed across the network. Therefore, while the results of the scenario modelling are useful for determining the high-level impact of electric vehicles on our LV network, it is important to validate them with real world measurements to inform our investment decisions. This is an important reason for monitoring our low voltage network. See Section 6.2.1.1.

In FY21, we completed a further, in-depth probabilistic study with EPECentre focussing on the most constrained LV network feeders identified by our high-level analysis. The purpose of this study was to analyse the variability in their performance based on EV battery capacities, and customer travel patterns and charging behaviour. The results illustrated a slight increase in the capacity of the LV network feeder to host EVs due to increased diversity in charging times and durations. The results reinforced the validity of Scenario 1 (1kW/EV at peak) from our high-level study, assuming EV owners maintain similar travel patterns to internal combustion vehicles.

6.2.1.4 LV network reinforcement

Based on LV modelling undertaken to date, we believe most of our low voltage network has sufficient capacity to meet demand in the short-to-medium term. However, as EVs are adopted by more households and businesses, and we gather more data on our low voltage network utilisation, it is expected reinforcement above historic levels will be required. We are currently reviewing our LV strategy and have increased our reinforcement budget forecast to address these constraints. The projected constraints on our LV network are predominantly located in urban areas.

Figure 6.2.3 illustrates their geographic distribution across our region by Stats NZ areas (SA2). Refer to Section 6.6.2.2 for details of our LV reinforcement programme.

Orion will undertake LV network reinforcement through a portfolio of measures such as addressing phase imbalance, upgrading and adding new distribution transformers, and installing new low voltage lines and cables. Where cost effective, we will also look at implementing non-traditional solutions to defer reinforcement such as static compensators (STATCOMs) to provide voltage support or network scale batteries to reduce distribution transformer and 11kV feeder demand at peak times. In some cases, we may undertake greater Distributed Energy Resources Management, for example EV smart charging, to reduce peak load.

These innovations deliver on our asset management strategy focus on embracing the opportunities to re-imagine our future network.

Based on LV modelling undertaken to date, we believe most of our low voltage network has sufficient capacity to meet demand in the short-to-medium term.

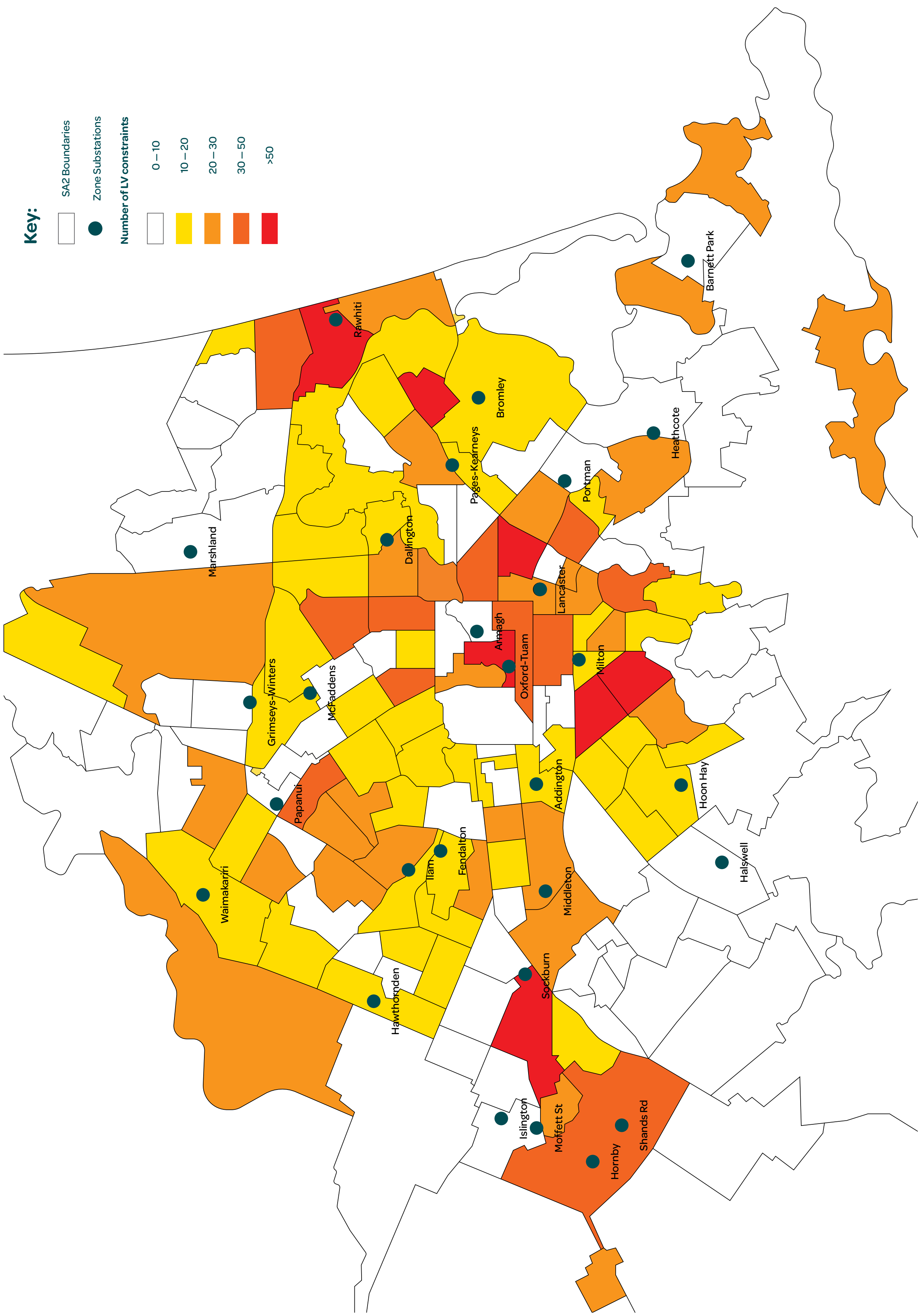


Figure 6.2.3 Projected LV urban network constraints (Scenario 1) in 2030 grouped by Statistics NZ SA2 definitions

6.2.2 Improving our systems

As our network evolves, we must ensure our processes and systems keep pace and adapt to our new requirements. In the future, we aim to develop our forecasting and modelling capability in addition to improving the overall integration of our operational systems.

6.2.2.1 Enhanced data analytics

Improving our data analytics capability will enable us to forecast and model a range of performance factors, including distribution transformer utilisation, voltage imbalance and power factor. The integration of this information with our other systems, such as our GIS platform will enable us to build a real-time digital model of our network.

Depending on the application, different forecasting and modelling techniques will be required to:

- allow the smart control of power electronics and energy storage, and in particular, the management of peak demand
- forecast load ahead of time to avoid outages as well as prolong the life of assets, translating into reduced customer interruptions
- assess investment choices for a subsequent financial year
- assess the potential impacts from scaled up adoption of low carbon technologies by customers, including clustering impacts

An enhanced digital network model will also enable improved:

- detection of electrical safety concerns both on our network and in customer premises which may be identified from smart meter information and our LV monitors
- power flow outputs which can allow us to identify voltage fluctuations, violation limits, fault currents etc., as a tool in the operation of our network

Improving our data analytics capability will enable us to forecast and model a range of performance factors, including distribution transformer utilisation, voltage imbalance and power factor.

6.2.2.2 Integration with operational systems and business processes

Our Advanced Distribution Management System (ADMS) will be incrementally upgraded to support the anticipated future requirements – avoiding the need to purchase and implement an entirely new system, see Section 7.16. Our view is improvements will build on our existing load management and upper South Island coordination expertise.

It is also our desire to develop our systems to allow non-discriminatory secure data access and transfer to eligible market parties and customers. To help ensure this occurs in an efficient manner for our customers we will continue collaboration with retailers and other industry players on technology development, process and communications platforms.

Current examples of this are:

- installing low voltage monitoring systems on our LV feeders
- discussions with smart meter providers around data access
- EV managed charging pilot

6.3 Preparing for growth

Network development is driven by growth in peak demand, not energy. The peak demand capability of our network is defined by network component capacities. For this reason, we concentrate on forecasting peak demand across all levels of our network, rather than energy usage.

The network development projects listed in this 10 year AMP ensure we can maintain capacity, quality and security of supply to support the forecast growth rates. Actual growth rates are monitored on an annual basis and any change will be reflected in next year's development plan.

Our network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury Plains and Banks Peninsula.

The factors and methodologies we use to estimate the quantity and location of load growth is described in our document: Long-term load forecasting methodology for subtransmission and zone substations. In summary, our method is to forecast growth at the zone substation level and translate this up to Transpower GXPs and finally to a total network demand forecast.

Our forecasts consider a range of scenarios from uptake of electric vehicles, battery storage and solar photovoltaics (PV) to changes in customer behaviours.

Our GXP and zone substation forecasts take account of our electric vehicle forecast, continued improvements in energy efficiency and growth in households and business associated with population growth. We have insufficient information to include any meaningful battery storage forecasts at this level but have included a possible scenario in the overall network total.

6.3.1 How we forecast demand growth

Our network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury Plains and Banks Peninsula.

Growth in electricity consumption in Christchurch and on Banks Peninsula has historically matched growth in population, including the holiday population for Banks Peninsula. Peak electricity consumption growth on the Canterbury Plains has been driven by changes in land use rather than population growth.

Besides weather, two other factors influence load growth:

- population increases
- changes in population behaviour

At a national level, it is reasonably easy to forecast population growth. When the national forecast is broken down to a regional level, the accuracy is less reliable but still useful in predicting future demand growth. At a regional level, we derive our load forecast from a combination of bottom-up inputs, such as household growth forecasts by Christchurch City Council and Selwyn District Council using Stats NZ 2018 projections and historical trends in growth.

6.3.1.1 Our network maximum demand

Maximum demand is the major driver of investment in our network so it's important for us to forecast it as accurately as we can. This measure is very volatile and normally varies by up to 10% depending on winter weather. Our network maximum half hour demand, based on load through the Transpower GXPs, for FY21 was 623MW during the peak that occurred on 1 July 2020, up 19MW from the previous year.

On 9 August 2021 load reached 712MW. Nationally, cold weather and insufficient generation contributed to the need for Transpower to issue a Grid Emergency Notice. At the evening peak, Orion was able to lower load to 672MW with normal load management.

In the medium-term maximum network demand is influenced by factors such as underlying population trends, new customers joining the network, growth in the commercial/industrial sector, changes in rural land use, climate changes and changes in customer behaviour.

Many things influence changes in customer energy consumption which are hard to predict in an era of rapid change. Some of the issues we need to consider are:

- **Electric vehicles** – EV uptake rates are uncertain, what proportion of EV drivers will charge at home and when, the diversity of home charging and what size charger will be used are all current unknowns
- **Customer actions** – how customers will respond to signals of high cost power or high CO_2 generation are unknown. A focus on decarbonisation could lead to improved house insulation, greater appliance efficiency, and customers responding to reduce peak load
- **Coal boiler conversions** – Government has introduced initiatives for business to move away from coal for industrial processes and heating. We are engaging with larger boiler users to gain insight into their decarbonisation plans
- **Solar photovoltaics** – the future uptake rate, and size of solar installations is uncertain
- **Batteries** – battery uptake rates remain uncertain, as does knowledge of how our customers will use batteries. Customers may discharge batteries at expensive evening peak times, and recharge the batteries at cheaper times, or may discharge their batteries when they get up in the morning and through the day – meaning evening electricity usage may still be from the grid

Given the range of impacts the changes in the energy sector will bring, we can no longer rely only on maximum demand forecasts based primarily on historical growth. Instead we've moved to scenario based maximum demand forecasting as shown in Figure 6.3.1.

All our maximum demand scenario planning assumes solar photovoltaics have no effect on the peak, which occurs on a winter evening after sunset – i.e. at a time when the sun isn't shining.

Our total network forecast is higher than the linear history due to the forecast population increase in our region, industrial development in Rolleston, and ongoing regeneration in the central city. Winter peak demand on our network is anticipated to increase by approximately 114MW (18%) over the next 10 years. This is based on the mid scenario shown in Figure 6.3.1. Significant volatility can be expected in annual actual maximum demands, with 10% variation depending on winter weather. Capital investment plans will be modified as load growth is observed.

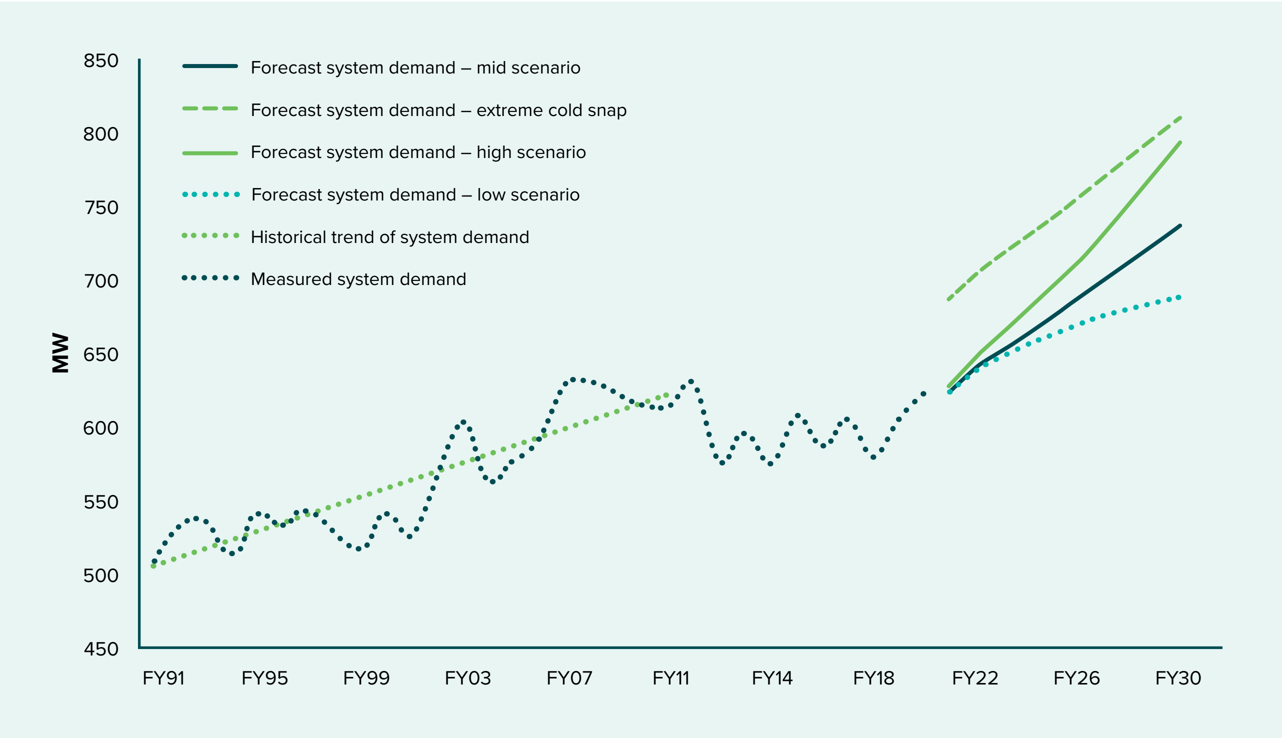
Our maximum demand is linked with cold weather. The extra growth in forecast maximum demand in the next few years includes new load from Te Pae Christchurch Convention and Exhibition Centre, Metro Sports facility, the Canterbury Multi-Use Arena and Lincoln University moving from coal to electricity for heating.

Descriptions of the four Figure 6.3.1 forecast scenarios are:

- **Low scenario** – the low scenario is based on continued energy efficiency at 0.5% per annum and battery storage, in either stationery or mobile form, being used to counter the impact of electric vehicle charging at peak – that is batteries inject power at peak to meet the charging needs of electric vehicles. The rate of coal boiler conversions to electricity is half that used in the mid scenario.
- **Mid scenario** – this indicates underlying growth from new residential households, industrial uptake and commercial rebuild. For EVs we have used Ministry of Transport potential uptake figures as a baseline. This assumes ~13% of the region's vehicle fleet will be electric in 10 years and we have assumed 20% charging at peak times. Energy efficiency continues to reduce peak demand

Given the range of impacts the changes in the energy sector will bring, we can no longer rely only on maximum demand forecasts based primarily on historical growth.

Figure 6.3.1 Overall maximum demand trends on the Orion network



by 0.5% per annum. We expect new business and residential buildings will be more energy efficient than the older buildings they replace. An allowance for coal boiler conversions has been included to align with Transpower's Te Mauri Hiko – Energy Futures vision.

This forecast does not include the effects of batteries which have more uncertain uptake and impact at peak winter times. The impact batteries have in reducing peak load is likely to be low compared to other uncertainties.

- **High scenario** – this high scenario shows the consequences of further energy efficiency gains becoming unattainable, coal boiler conversions matching the mid scenario and a trebling of the electric vehicle impact to match the highest scenario from the Climate Change Commission.
- **Potential extreme cold snap peak** – this forecast is based on events similar to those in 2002 and in 2011 when a substantial snowstorm changed customer behaviour. We experienced a loss of diversity between customer types. There was significant demand from residential customers due to some schools and businesses remaining closed. When planning our network, it is not appropriate to install infrastructure to maintain security of supply during a peak that may occur for two or three hours once every 10 years. This forecast is therefore used to determine nominal – all assets available to supply – capacity requirements of our network only.

6.3.1.2 Demand forecasting uncertainties

This section provides further detail on some of our assumptions about the more significant uncertainties we face in our demand forecasting.

Climate Change Commission

The Commission has provided advice to Government on actions to meet New Zealand's climate targets. This includes increasing EV uptake and coal boiler conversions. We have used ECAN consent information to locate large coal boilers and are contacting these major customers to gain insight into their decarbonisation plans. Initial indications are that some will use biomass rather than electricity, and some will use electricity for pre-heating rather than converting the entire boiler load.

While we are gaining clarity about customer's plans we have increased our forecast network total over the next 10 years to align with the Accelerated Electrification Scenario in Transpower's Te Mauri Hiko – Energy Futures. Our pricing incentivises major customers' reduction of use at peak times so the impact of boiler conversions on our peak load may be less than the total boiler electrification.

Utility-scale solar

Interest in utility-scale solar connections indicates potential for 10MW to 100MW+ of solar PV generation to be added within Region B. Summer peaks sometimes occur after 7pm

In the future, it is anticipated electricity networks will undergo major changes in consumer energy usage habits due to increased customer choice and the impact of climate change.

when solar radiation is reduced. Together with cloud cover the solar generation can be less than 5% of nameplate capacity at the time of peak load. We plan to monitor the output of these solar connections so their contribution can be excluded from our peaks which will reveal the change in underlying load. Standard forecasting methodology can be applied to this underlying load, with the solar output reported separately.

COVID-19

The impact of the worldwide COVID-19 pandemic and associated responses could change load. These changes could be due to:

- significant population growth as New Zealanders return home and immigrants seek safety here
- businesses closing as a result of lockdowns and curtailed international tourism

Current information indicates none of our Major Projects in the next two years are expected to change due to these factors.

Energy transformation and climate change

In the future, it is anticipated electricity networks will undergo major changes in consumer energy usage habits due to increased customer choice and the impact of climate change. At a national level, Transpower has produced their Te Mauri Hiko – Energy Futures long-term vision of future electricity use. The focus of this vision is the 20-50 year range as opposed to our 5-10 year planning horizon. Being at a national level it is difficult to translate this into the projected impact on our network. We will however use their underlying information where it provides a forecast that better matches observed changes compared with other projections.

Milk processing plants

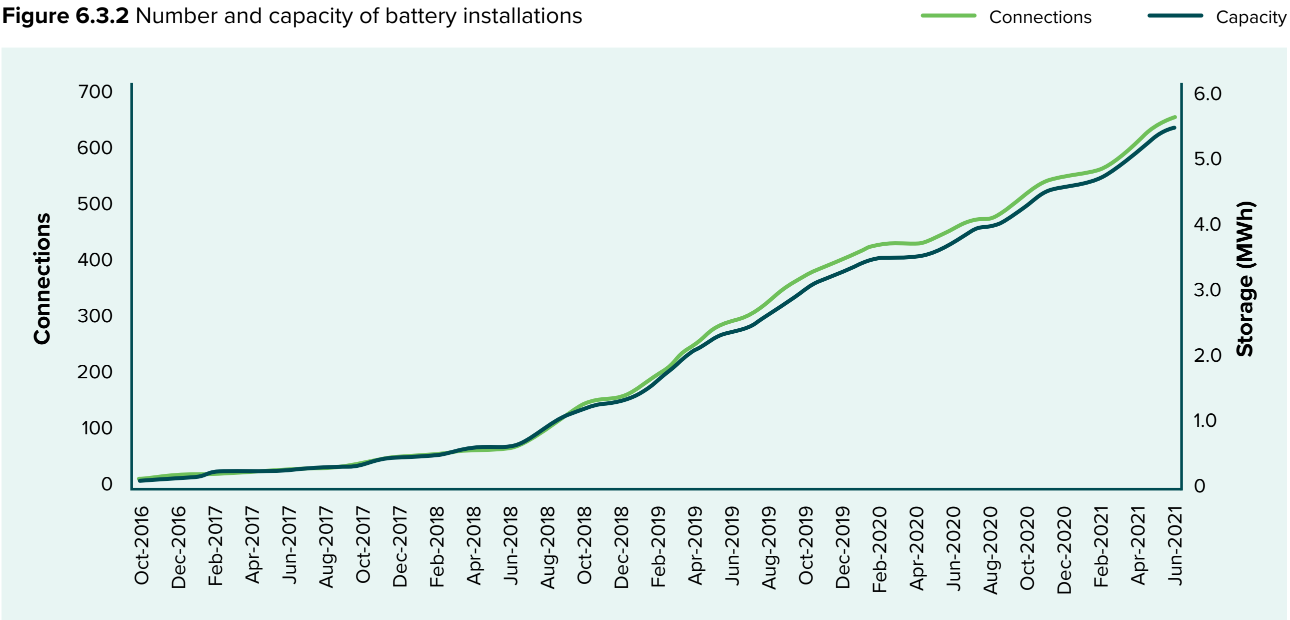
The timing and demand changes due to possible moves by milk processing plant operators causes significant forecasting uncertainty. For this reason, we are cautious about our development plans to ensure that we do not install assets that may later become underutilised.

Battery storage

Customer battery storage connected to our network has been increasing between 1 and 2MWh/year since January 2019 with the average capacity per installation being 8kWh. Although this is presently not significant, the charging and discharging orchestration of battery storage will influence the observed system peak as the battery capacity grows.

Figure 6.3.2 shows the number and capacity of battery installations on our network.

Figure 6.3.2 Number and capacity of battery installations

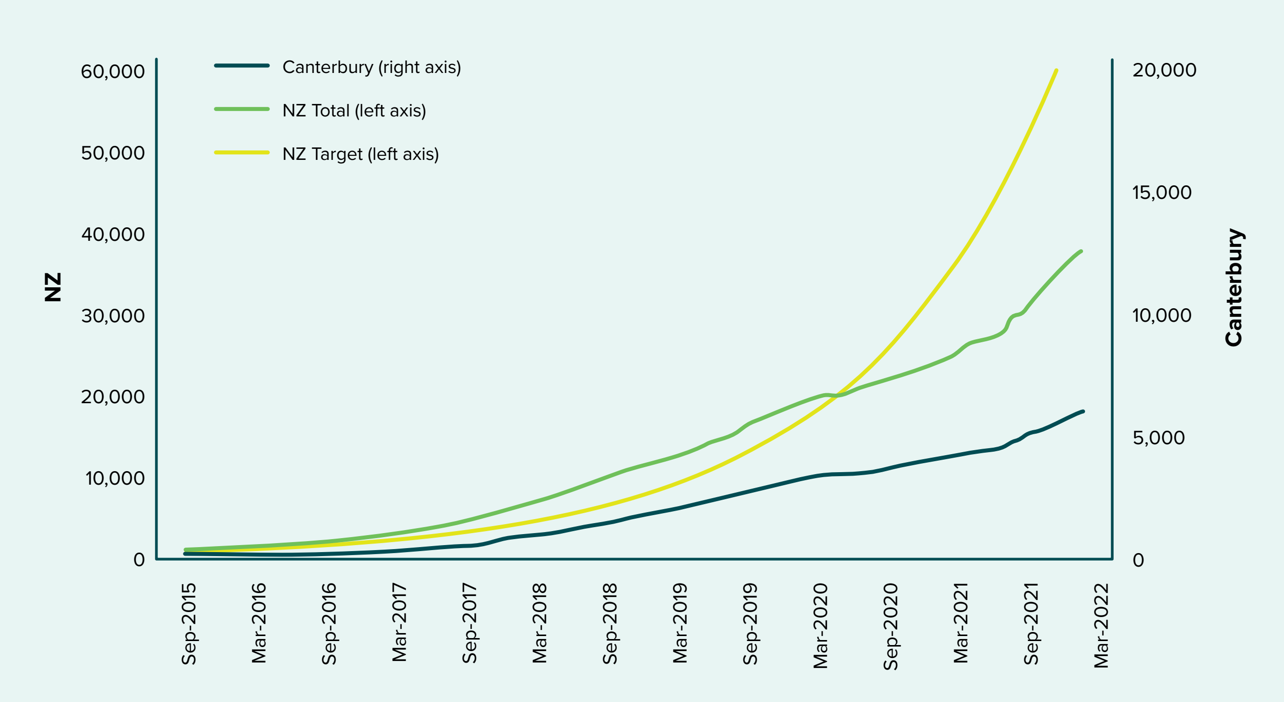


Electric vehicles

Electric vehicle uptake was increasing linearly until July 2021 when the Clean Car Discount was introduced. Uptake is expected to increase but limited by supply constraints. The majority of the local fleet are Nissan LEAF imports. Clustering of EV uptake due to neighbourhood demographics may impact areas of the low voltage network before overall numbers are substantial. Data from vehicle registrations indicates the suburbs with a higher concentration are Cashmere and Halswell. Figure 6.3.3 shows EV uptake has fallen below the NZ target.

We have conducted some preliminary research into the impacts of EV uptake on our LV network. Results of this research are summarised in Section 6.2.1.3.

Figure 6.3.3 Electric vehicle uptake in New Zealand and Canterbury



Distributed generation

In conjunction with University of Canterbury, and thanks to MBIE research funding, Orion contributed to the development of a Distributed Generation Connection Guideline. The guideline requires distributors to establish a Distributed Generation (DG) hosting capacity for each low voltage network feeder. This hosting capacity will be based on an expected medium-term uptake/penetration level.

Figure 6.3.4 shows solar uptake in terms of connections and capacity since 2008. Solar PV penetration is about 2% by network connection count and less than 1% of energy delivered. The installed capacity has reached 3%. Figure 6.3.5 shows that the uptake rate picked up again in 2021.

Figure 6.3.4 Current level of solar PV uptake on our network

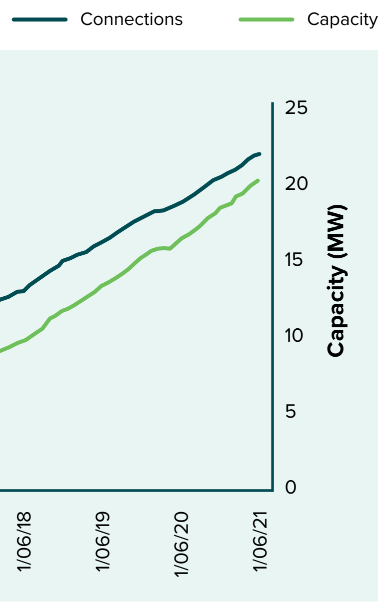
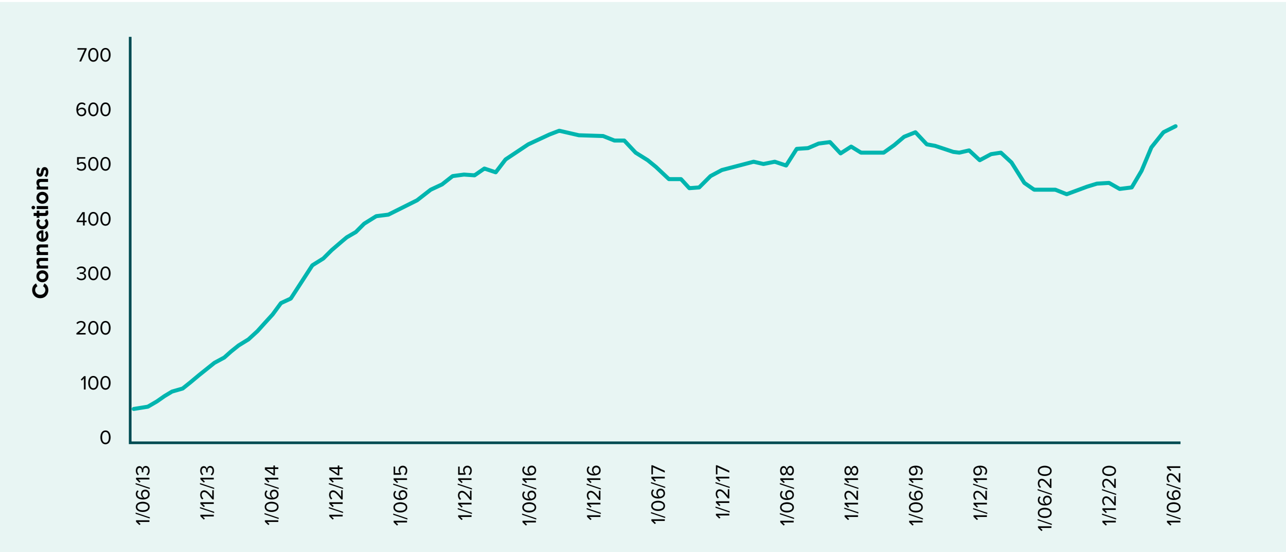


Figure 6.3.5 Rolling 12 month increase in solar PV connections



Subdivisions

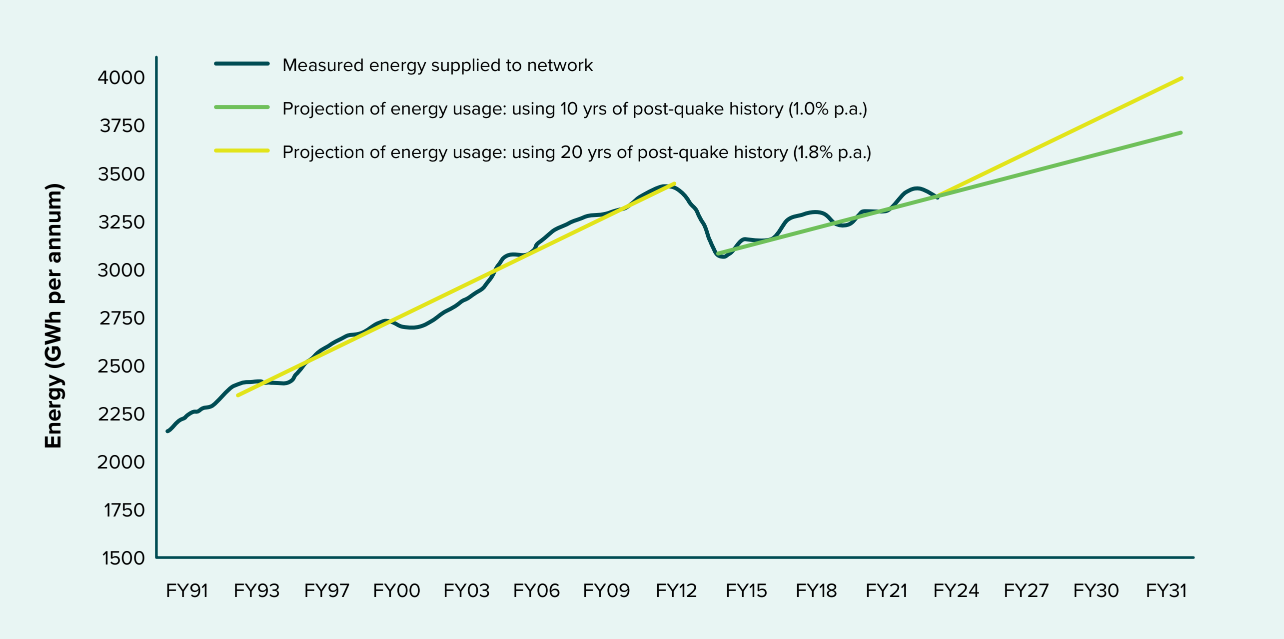
The level of subdivision activity depends on economic conditions and population growth. The response to COVID-19 may include an increase in immigration to NZ but data to inform forecasting is not yet available.

The most recent population forecast update has the annual increase in households remaining approximately 3,000 for several years then dropping to 2,000.

6.3.2 Our network's energy throughput

Prior to the 2010/11 Canterbury earthquakes, our network showed an average energy growth rate of about 1.8% per year, see Figure 6.3.6. The drivers behind this were population growth in Christchurch, growth in holiday population for Banks Peninsula and changes in land use on the Canterbury Plains. For the years post the Canterbury earthquakes, this rate decreased to approximately 1.0% per year, due to more energy efficient new housing and commercial buildings and more energy efficient domestic heating and production processes.

Figure 6.3.6 System energy throughput



6.3.3 Territorial authority growth

Our network spans two territorial authority areas: Christchurch City Council (CCC) and Selwyn District Council (SDC). The following information summarises our forecasts for each of these territorial areas, before we move into demand forecasts at GXP and zone substation level. Both territorial authorities publish useful area planning information and we use this to plan for growth on our distribution network. Their plans are informed by the Greater Christchurch Partnership which is a collaboration between local councils, iwi, and government organisations.

6.3.3.1 Christchurch city demand growth forecast – Region A

To forecast the growth in residential demand in the Christchurch city area, we map each of the census area units to one or more zone substations in our model.

To forecast industrial growth, we utilise Christchurch city industrial vacant land reports to identify areas developed and zoned for potential growth. We utilise historic uptake rates and market judgement to allocate 20Ha of growth per annum to the different areas of available land. These allocations are mapped in our model to a zone substation with a forecast load density of 130kW per hectare.

Large loads at specific points are identified through connection applications and allocated to the relevant zone substation. This is supplemented by use of CCC land zone maps to determine the areas suitable for commercial/ industrial infill growth. This part of our forecast is a relatively discretionary process and is heavily dependent on the vagaries of the commercial development market.

Overall Region A growth is winter dominated and follows the same trend as the maximum demand of the overall network. See Figure 6.3.1.

In the medium-term, CCC's District Plan review expects to deliver an increase in residential infill within the Christchurch central city and areas around shopping malls by introducing Medium Density Residential zones and Suburban Density Transition. In the short-term, major subdivision growth is planned for Halswell and the central city East Frame. Industrial development is expected to mainly continue in Islington, Belfast and airport areas.

6.3.3.2 Central Canterbury and Banks Peninsula demand growth forecast – Region B

For Region B, we use the latest SDC household growth projections to forecast residential growth in the greater Selwyn region. Most of our zone substations within Selwyn District are required to meet irrigation load and predominately have their peak load in summer. However, significant residential growth has occurred around Rolleston, Larcomb and Lincoln zone substations and these substations have their peak load in winter. Region B, the majority of which is in Selwyn District, network peak is anticipated to increase by approximately 18MW (12%) in the next 10 years.

We have started to receive enquiries about connecting utility-scale solar PV within Region B. This has potential to reduce the peak summer GXP load, but network capacity is still required for evening peaks and cloudy periods.

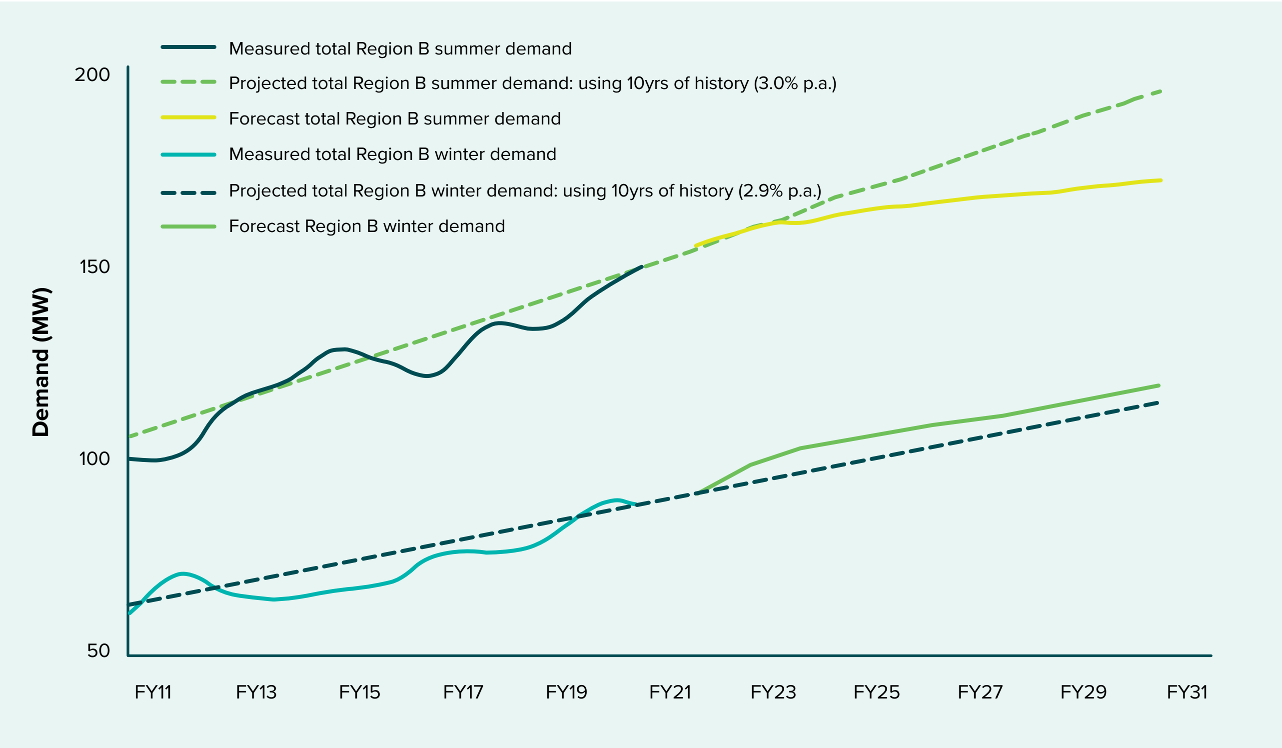
Figure 6.3.7 shows recent summer load growth in our Region B area. The FY21 summer peak included cooling load of ~9MW when the temperature reached 34°C.

Region B winter load growth is also shown in Figure 6.3.7 with the FY12 peak due to a significant August snowstorm.

The SDC residential forecast indicates significant growth is expected to continue around Rolleston, Prebbleton and Lincoln townships for a few years. Higher than normal growth is also expected due to planned development at Lincoln University.

The SDC residential forecast indicates significant growth is expected to continue around Rolleston, Prebbleton and Lincoln townships for a few years.

Figure 6.3.7 Region B maximum demand



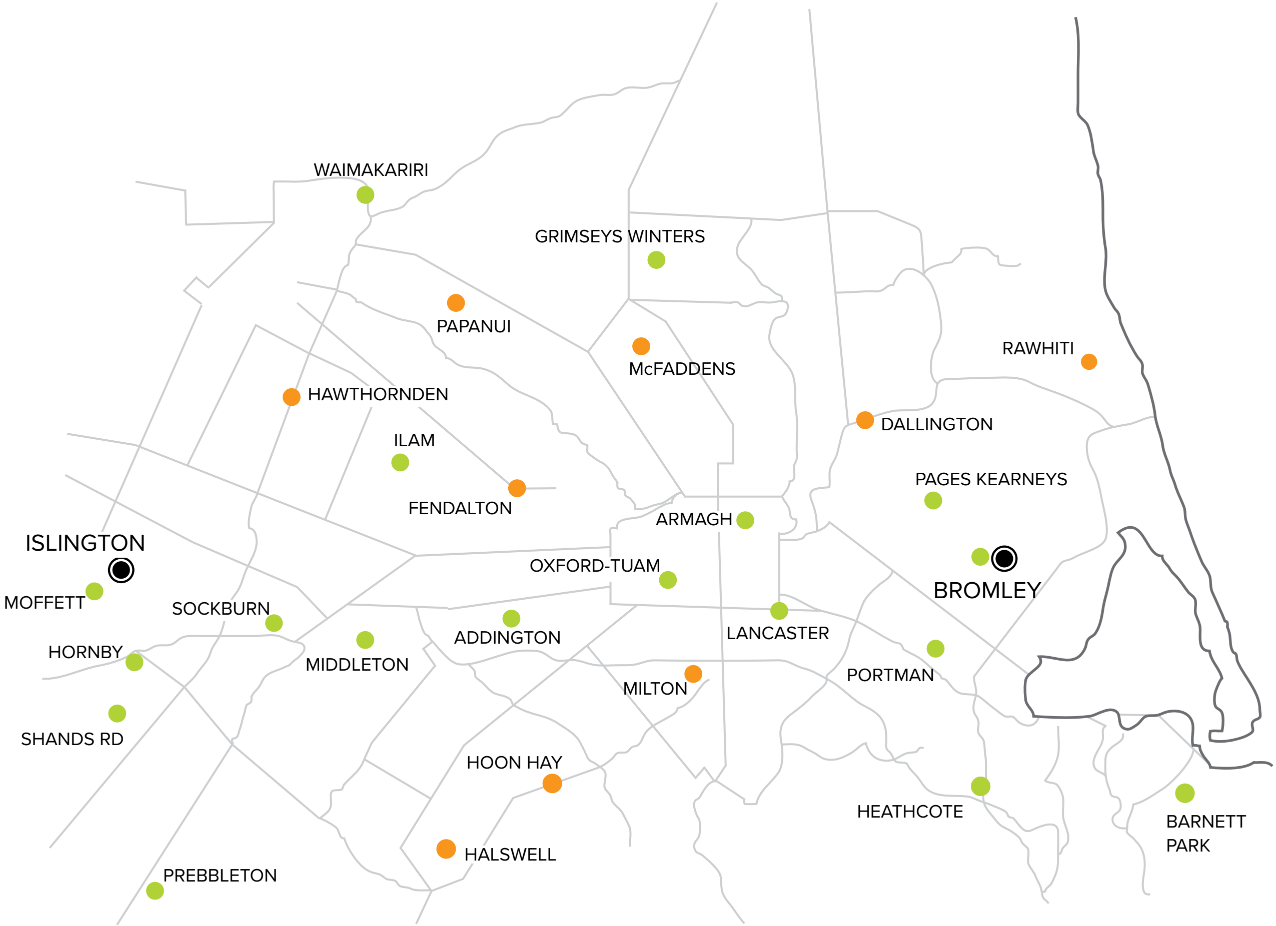
6.3.4 Present loading

Region A geographical map in Figure 6.3.8 demonstrates areas of high and moderate loading on our network.

The changes from our 2021 AMP are:

- Dallington and Rawhiti moved to more than 70%
- Hornby, Ilam and Sockburn moved to less than 70%

Figure 6.3.8 Zone substations – Region A FY21 maximum demand as a percentage of firm capacity



Key:

Transpower GXP

Maximum demand - as a percentage of firm capacity

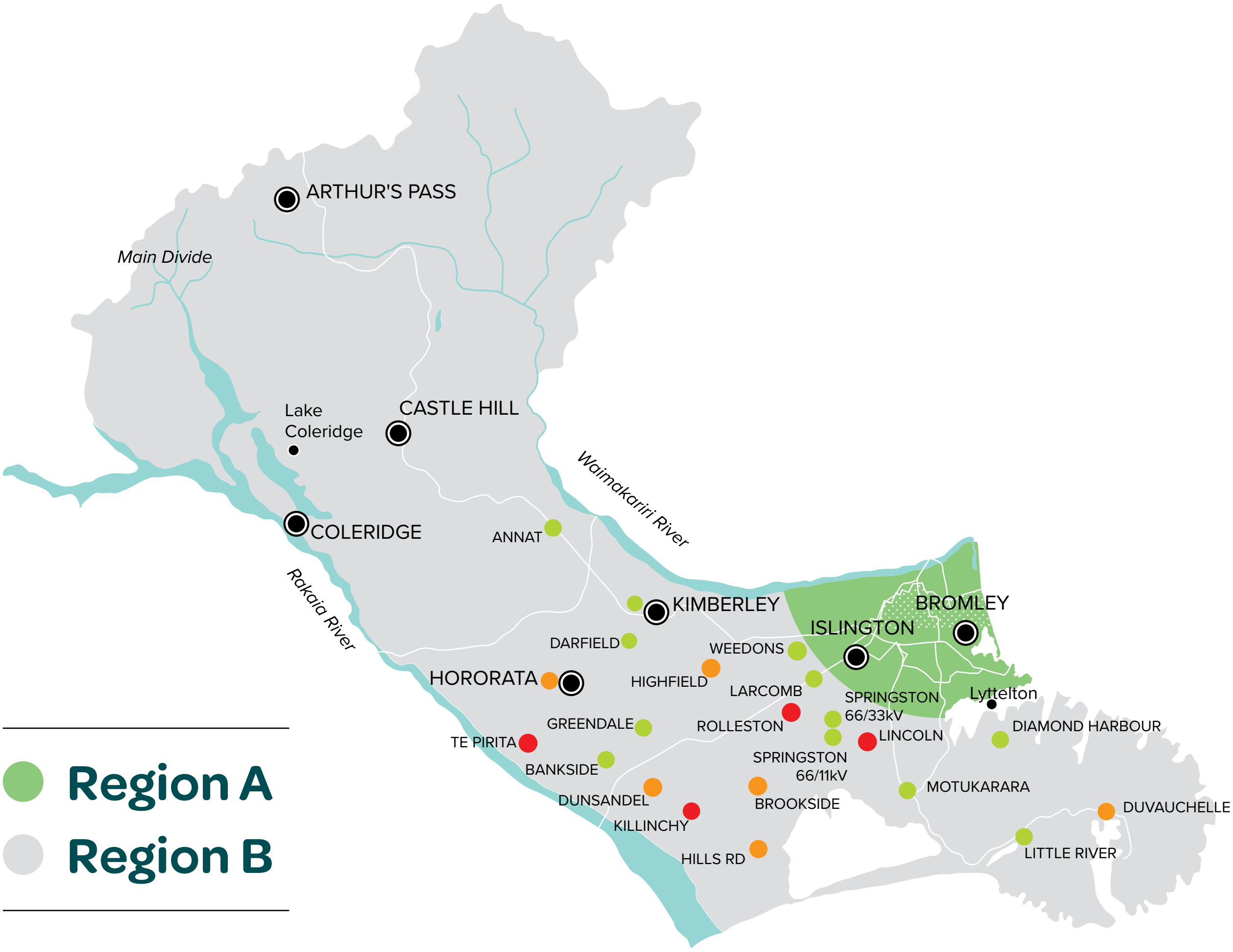
- More than 90%
- Between 70% and 90%
- Less than 70%

The Region B geographical map in Figure 6.3.9 demonstrates areas of high and moderate loading on our network. Substations with load exceeding 90% of firm capacity have been coloured red.

The changes from our 2021 AMP are:

- Te Pirita moved to more than 90%
- Hororata moved to less than 90%
- Duvauchelle moved to more than 70%.

Figure 6.3.9 Zone substations – Region B FY21 maximum demand as a percentage of firm capacity



Key:

Transpower GXP

Maximum demand - as a percentage of firm capacity

- More than 90%
- Between 70% and 90%
- Less than 70%

6.3.5 Load forecast

Using the inputs detailed in the previous sections, we have forecast our GXP and zone substation load for the next 10 years. Each substation is assigned a Security Standard Class which outlines our restoration targets under different contingency scenarios (refer to Section 6.4.1 for further details). Firm capacity is determined by calculating the remaining capacity of each site should one item of plant fail (N-1).

6.3.5.1 Transpower GXP load forecasts

Table 6.3.1 indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands over the next 10 years are also shown.

Note the impact of projects incorporated in this plan is not reflected in the GXP load forecasts. The tabled loads are those expected if no development work is undertaken. Firm capacity is the capacity of each site should one item of plant fail. See Section 5.2 for a map of Transpower's system.

Table 6.3.1 GXP substations – load forecasts (MVA)

GXP substation	Security Standard Class	Firm capacity	Actual FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Bromley 66kV	A1	220	142	141	142	143	144	145	145	146	147	148	149	154
Islington 33kV	B1	107	67	68	72	74	75	76	78	79	81	82	83	87
Orion Islington 66kV	A1	480 [1]	402	406	418	428	434	440	444	448	453	458	464	479
Hororata 33kV [2]	C1	23	21	21	21	21	21	21	22	22	22	22	22	22
Kimberley 66kV, Hororata (66 & 33kV)	C1	70 [3]	49	49	49	50	50	50	50	51	51	51	51	52
Arthur's Pass	D1	3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Castle Hill	D1	3.75	0.6	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Coleridge	D1	2.5	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Notes:

1. **532 MVA total firm capacity.** Assumes only 45% of Mainpower's load is fed from Islington post Islington T6 contingency. Emerging constraint to be managed by transferring Larcomb and Weedons to Norwood GXP
2. **Monitor growth and transfer load to Hororata 66kV if needed in the short-term.** Project 604 scheduled for FY26/27 to reduce loading on this GXP by transferring Bankside from the 33kV to the 66kV subtransmission network.
3. **Assumes full generating capacity available from Coleridge.** Can be limited to 40MW capacity when Coleridge is not generating or providing reactive support

6.3.5.2 Zone substation load forecasts

The following two tables compare the firm capacity of each of our zone substations with present and forecast load.

The electric vehicle uptake scenario and customer actions described in Section 6.3.1.1 have been incorporated into the forecasts. The uptake of residential solar PV connections is being recorded but not incorporated into the forecasts because the impact on zone substation peak demand, especially winter peaking areas, is negligible. At this stage we have not incorporated the impact of battery storage into our zone substation forecasts as we do not anticipate the impact of batteries to be significant at the zone substation level within the next 10 years.

The "Year 10 High EV Impact" in the final column of Table 6.3.2 shows the potentially higher load if there is:

- clustering of EV uptake three times higher than the network average. This scenario allows for accelerated localised uptake due to neighbourhood influence i.e. neighbours are more likely to buy an EV, if EVs are more common in the area, and
- diminished response to measures to encourage charging away from peak. This allows for twice as many charging at 6pm i.e. 40% of EVs

Table 6.3.2 Region A 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Year 10 High EV Impact
Addington 11kV #1	B2	30	16	16	16	19	19	19	19	19	19	19	20	20	21
Addington 11kV #2	B2	30	18	18	18	18	18	18	18	18	18	18	19	19	20
Armagh	A2	40	18	19	19	20	21	22	22	23	23	24	25	26	27
Barnett Park	B3	15*	10	10	10	10	10	10	10	10	10	10	10	10	11
Bromley	B2	60	32	32	32	33	33	33	33	33	34	34	34	35	38
Dallington	B2	40	28	28	28	28	28	28	28	29	29	29	29	29	33
Fendalton	B2	40	35	35	35	35	35	35	35	35	35	35	35	35	38
Halswell	B2	23	19	20	21	22	22	23	23	24	24	25	25	26	29
Hawthornden	B2	40	33	32	33	33	33	33	34	34	34	34	35	35	38
Heathcote	B2	40	23	23	23	24	24	24	24	24	24	25	25	25	27
Hoon Hay	B2	40	30	30	30	30	30	30	31	31	31	32	32	33	35
Hornby	B2	20	13	13	14	14	14	14	14	14	14	14	14	14	15
Ilam	B3	11	7	7	8	8	8	8	8	8	8	8	8	8	8
Lancaster	A2	40	17	17	17	18	18	18	18	18	18	19	19	19	21
McFaddens	B2	40	35	35	35	35	35	35	36	36	36	36	36	37	39
Middleton	B2	40	26	26	26	26	28	28	28	28	28	28	28	28	28
Milton	B2	40	35	35	36	36	36	36	37	37	37	38	38	38	41
Moffett	B3	23	14	15	15	16	16	16	17	17	18	18	18	19	19
Oxford Tuam	A2	40	15	16	16	16	16	17	17	17	17	17	17	17	18
Papanui	B2	48	42	42	42	43	44	44	45	45	46	47	47	48	49
Prebbleton	B3	15	7	7	8	8	8	9	9	9	9	9	10	10	10
Rawhiti	B2	40	30	30	30	30	30	30	30	30	30	30	30	30	33
Shands	B3	20	13	16	17	17	17	17	18	17	18	18	19	20	20
Sockburn	B2	39	23	22	22	23	23	23	23	23	23	23	23	24	25
Waimakariri	B2	40	19	19	20	20	20	21	21	21	21	22	22	22	23

* 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

Our proposed resolution is:

Halswell	Load transfer to Hoon Hay & Shands then a transformer upgrade
Milton	Load transfer to Addington zone substation
Papanui	Transfers to Waimakariri & new Belfast zone substation
Shands	Upgrade capacity with site conversion to 66kV

6.3 Preparing for growth continued

Table 6.3.3 Region B 66 and 33kV zone substations – load forecasts (MVA)

Zone substation	Security Standard class	Firm capacity	Actual winter FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Year 10 High EV Impact
Annat*	C4	7.5	3.5	4	4	4	4	4	4	4	4	4	4	4	4
Bankside*	C3	10	4.1	4	4	4	4	4	4	4	4	4	4	4	4
Brookside 66kV*	C3	10	8.6	9	9	9	9	9	9	9	9	9	9	9	9
Darfield*	B3	8.8	5.1	5	5	5	5	5	5	6	6	6	6	6	6
Diamond Harbour*	B3	7.5	2.5	2	3	3	3	3	3	3	3	3	3	3	3
Dunsandel	A2	23	19.8	20	20	20	20	20	20	20	20	20	20	20	20
Duvauchelle	B3	7.5	5.3	5	5	5	5	5	5	5	5	5	5	5	5
Greendale*	C3	10	6.7	7	7	7	7	7	7	7	7	7	7	7	7
Highfield*	C3	10	8.5	8	8	8	9	9	9	9	9	9	9	9	9
Hills Rd*	B3	10	7.2	8	8	8	8	8	8	8	8	8	8	8	8
Hororata*	C3	10	8.2	8	8	8	8	8	8	8	8	8	8	8	8
Killinchy*	C3	10	9.2	9	9	9	9	9	9	9	9	9	9	9	9
Kimberley	A3	23	15.4	15	15	15	15	15	15	15	15	15	15	15	15
Larcomb	B3	23	14.2	15	16	16	17	17	18	19	19	20	21	22	24
Lincoln	B3	10	10.3	9	9	10	10	10	10	11	11	11	11	11	12
Little River*	C4	2.5	0.7	1	1	1	1	1	1	1	1	1	1	1	1
Motukarara	C4	7.5	3.4	3	3	3	3	3	3	3	3	3	3	3	3
Rolleston	B3	10	9.8	11	11	11	11	12	12	12	12	13	13	13	14
Springston 66/33kV	B2	60	34.2	39	38	40	41	42	42	43	43	42	42	42	43
Springston 66/11kV*	B3	13	7.1	9	10	11	11	11	12	12	12	12	12	12	13
Te Pirita	C3	10	9.0	9	9	9	9	9	9	9	9	9	9	9	9
Weedons	B3	23	14.2	16	18	18	18	19	19	19	19	20	20	20	21
Lincoln + Springston		20	15.9	17	19	21	21	21	22	22	23	23	23	24	25

* Denotes single transformer or line substation

Indicates load greater than firm capacity

Our proposed resolution is:

Highfield	Load shift from Rolleston will lead to constraint at Highfield which is resolved by new substation at Norwood
Larcomb	Load shift to Rolleston if needed
Lincoln & Springston	Load shift from Lincoln to Springston where a second transformer added when needed giving combined firm capacity of 43MVA
Rolleston	Load shift to Highfield (where transformer will be rerated when customer upgrade confirmed), then construct new Burnham 23MVA substation to replace Rolleston

6.4 Planning criteria

When planning our network, we:

- take account of customer feedback to determine the value they put on reliability, resilience, focus on the future and sustainability
- preserve our HV security of supply standard, which is the ability of our network to meet the demand for electricity when electrical equipment fails
- monitor our network utilisation thresholds to prepare an annual reinforcement programme for our network
- compare our current network capacity with load forecast scenarios. The resulting projects are based on our design standards
- projects are based on our design standards. The projects are then prioritised taking account of the ability to deliver the work each year
- consider, especially as the network becomes constrained, non-network solutions to relieve these constraints as an alternative to or to delay network investment

Security of supply underpins our HV network resilience.

6.4.1 HV security of supply standard

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. 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.

Security of supply underpins our HV network resilience. It is grounded in the flexibility of our network to be reconfigured to provide power from alternative sources when needed. Security of supply differs from reliability, which is how the network performs, measured by the frequency and duration of power outages per customer.

In addition to our security of supply standard, customers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We will also make changes to individual security of supply arrangements for existing customers.

Our security of supply standard caters for connections of sizes that meet our major customer's needs and individual security arrangements on our network are minimal. They are mainly limited to high profile services such as hospitals, ports, Christchurch International Airport and public sports venues. We also have in place individual security of supply agreements with milk processing plants at Darfield and Dunsandel.

Our Network Security of Supply Standard is shown Table 6.4.1.

6.4 Planning criteria continued

Table 6.4.1 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

Note 1. Assumes the use of interruptible irrigation load for periods up to 48 hours.
Note 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 Network utilisation thresholds

Historic loading data from our DMS and forecast zone substation and subtransmission utilisation figures are used to prepare our 10-year programme of works for our network.

Growth at the 11kV distribution level is largely dependent on individual subdivision development and customer connection upgrades. Growth in excess of the system average is not uncommon and localised growth rates are applied as necessary. 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
- **Bus fault 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 security of supply standard, the location and quantity of load supplied by a feeder has a bearing on whether all or only some of the four load categories described above should be applied to an asset for analysis.

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

6.4.3 Capacity determination for new projects

When a capacity or security gap is identified on the network we consider different capacity 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.

When comparing different capacity solutions, we use the Net Present Value (NPV) test. The NPV test is an economic tool that analyses the profitability 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 that can ultimately result in stranded assets.

The capacity of a new zone substation and 11kV feeders is generally dictated by the desire to standardise network equipment. The capacity of a zone substation and transformer/s is based mainly on the load density of the area to be supplied and the level of the available subtransmission voltage. 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 new cables. When overhead line capacities are exceeded, an upgrade of the current carrying conductor may be feasible. However, the increased weight of a larger conductor may require that the line 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. We discuss our approach to increased capacity in our architecture and network design document.

Table 6.4.2 provides a summary of our standard network capacities.

Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair.

Table 6.4.2 Standard network capacities

Location	Subtransmission voltage	Subtransmission capacity		Zone substation capacity	11kV feeder size [Notes 1 & 2]	11kV tie or spur [Note 1]	11/400kV 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.

6.4.4 Project prioritisation

Prioritisation of network solution projects for capacity and constraints is a complex process that involves multiple factors that are both external and internal to Orion.

The primary factors to be considered when prioritising projects, in decreasing order of significance, are:

- **Coordination with NZ Transport Authority and local authority civil projects** – where projects are known to occur in the same location, we aim to schedule our projects to coincide with the timing of key civil infrastructure projects by these two parties. 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 cables or excavate and then reinstate newly laid road seal.
- **Satisfying individual or collective customer expectations** – we work hard to satisfy the needs of our customers. We give priority to addressing constraints most likely to impact customer supply through extended or frequent outages, or compromised power quality.
- **Managing service provider resource constraints** – we aim to maintain a steady workflow 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.
- **Coordination with Transpower** – we endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and provide direction to Transpower to ensure consistency with our sub-transmission upgrade plans.
- **Our asset replacement programme** – we extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations.
- **Our asset maintenance programme** – we seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes, for example zone substation transformer refurbishment.

After assessing their relative priorities, the final decision to undertake investment in projects for the coming year depends on urgency. Other factors also apply, such as seasonal timing to avoid taking equipment out of service during peak loading periods. This means we endeavour to undertake projects in metropolitan areas in summer and projects in farming areas in winter. It is also important we consider the order of interconnected projects.

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.

The recent and forecast improvement in battery technology and forecast drop in price is likely to create new Distributed Energy Resources Management opportunities in the short to medium-term. We will continue to monitor and investigate opportunities.

For some major projects, we would consider paying for Distributed Energy Resources Management to avoid or defer network development. These projects, and an indication of the value possible are detailed in Section 6.7.

6.4.5 Non-network solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we look for network switching options and then consider the following alternatives:

- Distributed Energy Resources Management
- Distributed Generation
- Uneconomic connections

Distributed Energy Resources Management provides an alternative to transmission and distribution network development.

6.4.5.1 Distributed Energy Resources Management

Distributed Energy Resources Management provides an alternative to transmission and distribution network development.

We are open to exploring projects with customers or third parties in the DER space and are keen to partner where there are mutual benefits.

This promotes efficient operation of the network.

Some of the gains from Distributed Energy Resources Management are:

- increased utilisation of the network
- improved utilisation of Transpower's transmission capacity
- customers benefit by becoming more efficient in the utilisation of energy and network capacity
- customer relations improve through less upward pressure on prices

The following Distributed Energy Resources Management strategies are applied by Orion:

- ripple system – anytime hot water cylinder control
- ripple system – night rate price options
- ripple system – major customer price signalling
- ripple system – interruptible irrigation
- coordinated upper South Island load management
- power factor correction rebate
- diesel-fueled generation

Ripple control

Ripple control is one of the most effective tools available for implementing Distributed Energy Resources Management.

Ripple control has facilitated the implementation of the following Distributed Energy Resource Management:

- hot water cylinder control – 50MW of peak load deferment
- night store heating – 190MW of night load providing an estimated 75MW peak reduction
- peak price signalling mainly major customers – 25MW, includes embedded generation
- interruptible irrigation load groups (summer only) – 15MW during contingencies

We will continue to work with retailers, customers and meter owners to ensure that the benefits of ripple control are retained during any transition to other technology options.

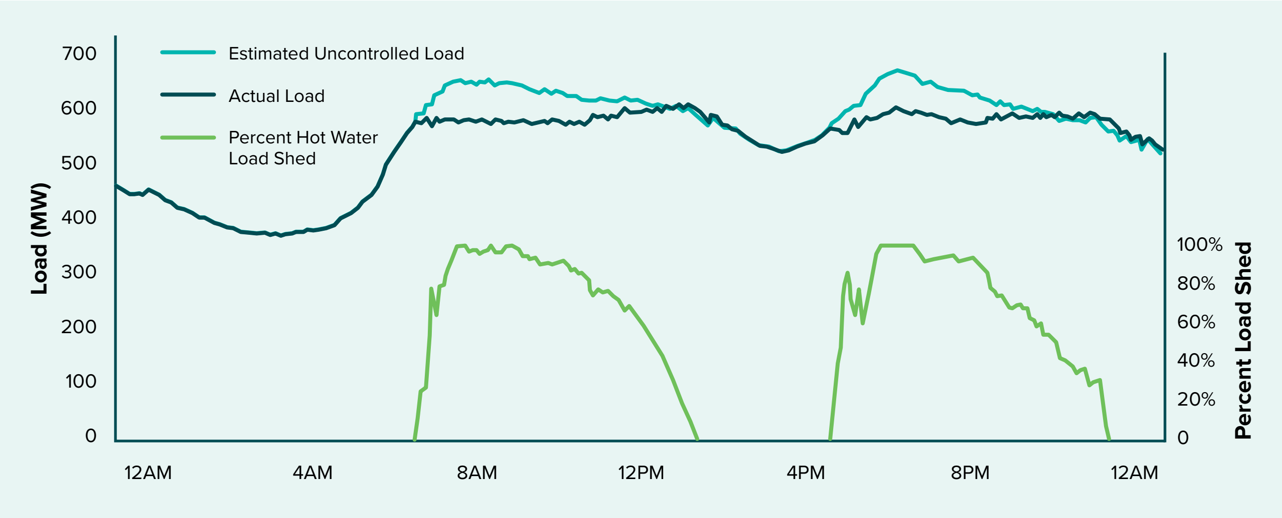
Winter load management

We design our network to meet peak demand, which we manage through hot water cylinder peak control and night rate price signalling. As network development costs and the transmission grid usage charges are driven by peak demand, the growth in the cost to our customers has been kept much lower than growth in overall annual demand.

A demonstration of the effectiveness of our winter load management, via hot water cylinder control and peak price signalling, in reducing the overall network load is shown in Figure 6.4.1.

Ripple control is one of the most effective tools available for implementing Distributed Energy Resources Management.

Figure 6.4.1 Example of a winter peak day demand profile



Note: uncontrolled load is our estimate of the loading levels that would have occurred if we had not controlled load.

Coordinated upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network we also provide a service to coordinate the management of hot-water cylinders on 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.

Cooperation and the coordination of upper South Island load management enables us to reduce peaks without excessive control of hot-water cylinders.

Interruptible load groups – irrigation

Orion offers an Irrigation Interruptibility Scheme where we pay rebates to customers who allow us to interrupt the supply to designated irrigators during a capacity emergency to help keep the power on for the wider community.

Used only rarely, the scheme allows Orion to reduce the load to irrigators leaving sufficient capacity remaining in the network to continue to supply electricity to more essential services, such as dairy sheds and medical centres.

It also means we do not need to invest in infrastructure to maintain services in an emergency in many rural areas, keeping costs and prices down for customers.

Power factor correction rebate

If a customer's load has a poor power factor then our network and the transmission grid are required to deliver a higher peak load than is necessary. This may lead to the need for an upgrade.

Our Network Code requires all customer connections to maintain a power factor of at least 0.95. In the Christchurch urban area where the predominately underground network is high in capacitance which helps to improve power factor, the minimum 0.95 power factor requirement has resulted in an overall 0.99 GXP power factor at times of network peak. This is a good outcome and any further benefit from offering financial assistance to correct power factor in the urban area would be uneconomic.

However, in the rural area, the predominately overhead network is high in inductance which reduces power factor and we offer a financial incentive in the form of a 'power factor correction rebate' to irrigation customers with pumping loads greater than 20kW. The rebate provides an incentive for irrigators to correct their power factor to at least 0.95. The rebate is set at a level where it is economic for the customer to provide power factor correction, which is lower than the avoided network investment cost associated with power factor related network upgrades.

6.4.5.2 Distributed Generation

The purpose of our distribution network has been to deliver bulk energy from Transpower GXPs to customers. In certain circumstances it can be more economic for the customer to provide a source of energy themselves in the form of Distributed Generation. Distributed Generation may also reduce the need to extend our network capacity.

We approach Distributed Generation in different ways, depending on the size of the system. For Distributed Generation above 750kW we consider the following issues:

- coincidence of Distributed Generation with Transpower interconnection charges
- benefits of avoided or delayed network investment
- security of supply provided by generators as opposed to network solutions
- hours of operation permitted by resource consents
- priority order for calling on peak lopping alternatives, such as hot-water control versus Distributed Generation

Region A load peaks on a winter evening when there is no solar PV generation. Diesel generation can reduce peak loads so is included in our peak forecast. Solar PV may offer a reduction to peak demand on our Region B network which is driven by summer irrigation load.

For diesel generation to be effective we require a contract to ensure peak lopping is reliably achieved. This is done through pricing structures that encourage users to control load at peak times. An incentive for major customers to generate electricity is provided through our pricing structure which includes an avoidable control period demand charge.

6.4.5.3 Uneconomic connections policy

When an application for a new or upgraded larger connection is requested, we undertake an economic assessment of the connection. This assessment determines whether our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic, and existing customers would be subsidising the new connection, then a connection contribution is required from the new customer. This policy ensures that the true cost of providing supply is passed on to the appropriate customer and allows them to make the right financial trade-offs.

6.5 Network gap analysis

We analyse the network for gaps using our Security of Supply Standard, see Table 6.4.1. It is a guide to the level of capital investment required in future network expansion to deliver the desired level of reliability performance expected by connected customers. The standard provides a sound basis for balancing the cost of providing the service with the value placed on that service by the customer.

Our 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 will, or will not, occur following an asset failure and if so the length of time that customers can 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 the network planning 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 of Supply Standard, then a gap in security is listed in Table 6.5.2. Before implementing a major solution to eliminate a security gap, our network planning team ensures that the solution can be justified with economic analysis and a risk assessment.

In general, network security gaps fall into the following categories:

- solution is currently uneconomic, and an economic solution is not anticipated in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but network expansion in adjacent areas is expected to provide a security improvement in the future
- solution requires co-ordination with Transpower’s asset replacement programme and/or is subject to Transpower/Commerce Commission approval

The economic analysis we undertake when considering investments to improve network security take into account the High Impact Low Probability (HILP) nature of the risks involved.

Transpower is required to maintain an N-1 level of security for the core grid as stated in the Electricity Industry Participation Code which includes a national transmission grid reliability standard. The GXP gaps identified in Table 6.5.1 are based on the application of our Security of Supply Standard to Transpower’s core-grid, spur or GXP assets.

6.5 Network gap analysis continued

Table 6.5.1 and Table 6.5.2 only show current Security of Supply Standard gaps. Additional projects listed in this 10 year AMP provide solutions for future forecast gaps that are not stated here. Some projects address more than one security gap and are therefore quoted in more than one location.

Table 6.5.1 Transpower GXP security gaps

GXP	Network gap	Solution	Proposed date
Islington	Partial loss of restoration for an Islington 220/33kV dual transformer failure	Upgrading Shands Rd ZS from 33kV to 66kV introduces greater 11kV tie capability to remaining zone substations supplied by Islington 33kV	FY31-32
Hororata	Interruption to all Hororata GXP load for a 66kV bus fault (restorable) Only partial restoration achievable for a Hororata 66/33kV dual transformer failure	Long-term solution of feeding load from proposed Norwood GXP. This requires all the remaining 33kV zone substations fed from Hororata GXP to be converted to 66kV. We have a set of projects that establishes a 66kV tie from Norwood GXP to Hororata GXP via Greendale ZS (Projects 1086, 1087 and 1072). This programme will enable fast restoration for a loss of the Hororata 66kV GXP	Beyond the current AMP 10 year period

Table 6.5.2 Subtransmission network security gaps

Substation	Network gap	Solution	Proposed date
Dallington	Loss of 28MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Complete a 66kV loop back to Bromley. Project 491	FY27-28
Rawhiti	Loss of 30MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.		
Hororata	Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable).	Installation of a bus coupler as part of 33kV switchgear replacement. Project 1064	FY27
Waimakariri	Loss of 20MW of load for a single 66kV circuit	Complete a 66kV loop from Papanui via Belfast and Waimakariri. Projects 491 and 942	FY27-28
Lancaster	Loss of 17MW of load for a single 66kV cable failure. Restoration achievable in 5 minutes.	Overall objective: complete a 66kV loop from Hoon Hay to Milton. Bromley to Milton ZS 66kV cable (Project 962) Lancaster ZS to Milton ZS 66kV (Project 589) Milton ZS 66kV switchgear and building. Project 723	FY24-25
Hororata to Springston 66kV circuit	The load on the 66kV overhead circuit between Springston and Hororata is in excess of 15MVA but still experiences an interruption for a single overhead line fault	Complete a 66kV closed loop between Norwood – Dunsandel – Killinchy – Brookside ZS's. Projects 940, 941 and 946	FY23-24

6.6 Network development proposals

This section lists our project proposals 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. Where economic, projects have been designed to meet our Security of Supply Standard requirements. See Section 6.4.1.

We account for the time it takes to plan and undertake the proposed projects for network improvements. This includes:

- 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

A major 66kV or 33kV network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. A 400V solution can take several months. In this context, it is prudent to be flexible in how we implement our network development proposals, rather than rigidly adhere to a project schedule based on an outdated forecast.

6.6.1 HV programmes of work and other projects

The following section outlines our Network Development HV 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. In contrast, projects in the latter five years are only outlined by project name, an indicative construction year, and their strategic driver(s).

There are ten main programmes of work scheduled in the 10 year period:

- Region A 66kV subtransmission resilience, Section 6.6.1.1
- Southwest Christchurch growth and resilience, Section 6.6.1.2
- Northern Christchurch network, Section 6.6.1.3
- Region A subtransmission capacity, Section 6.6.1.4
- Region B 66kV subtransmission capacity, Section 6.6.1.5
- Customer driven subtransmission projects, Section 6.6.1.6
- Lincoln area capacity and resilience improvement, Section 6.6.1.7
- Rolleston area capacity and resilience, Section 6.6.1.8
- Hororata GXP capacity and resilience, Section 6.6.1.9
- Distribution network reinforcement projects, Section 6.6.1.10

The following Region A and Region B maps indicate the location and timing of individual forecast major HV projects in this 10 year period, and the details of each project follow.

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 have specified the investment drivers for each programme of work, and their link to our Group Strategy, see Section 2.8.

The key for the investment drivers is:

Primary driver:

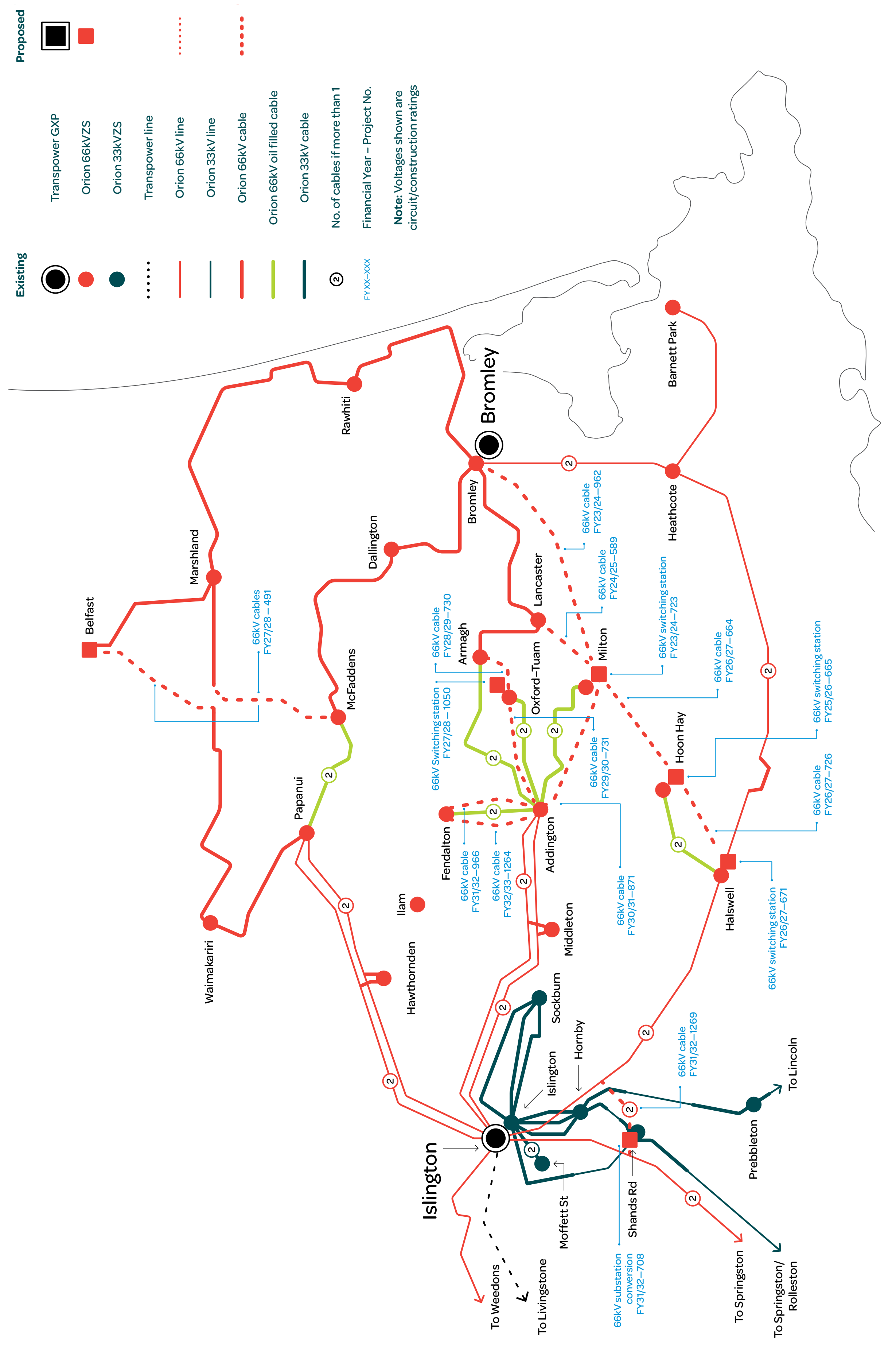
Primary

Secondary driver:

Secondary

6.6 Network development proposals continued

Figure 6.6.1 Region A subtransmission 66kV and 33kV – existing and proposed



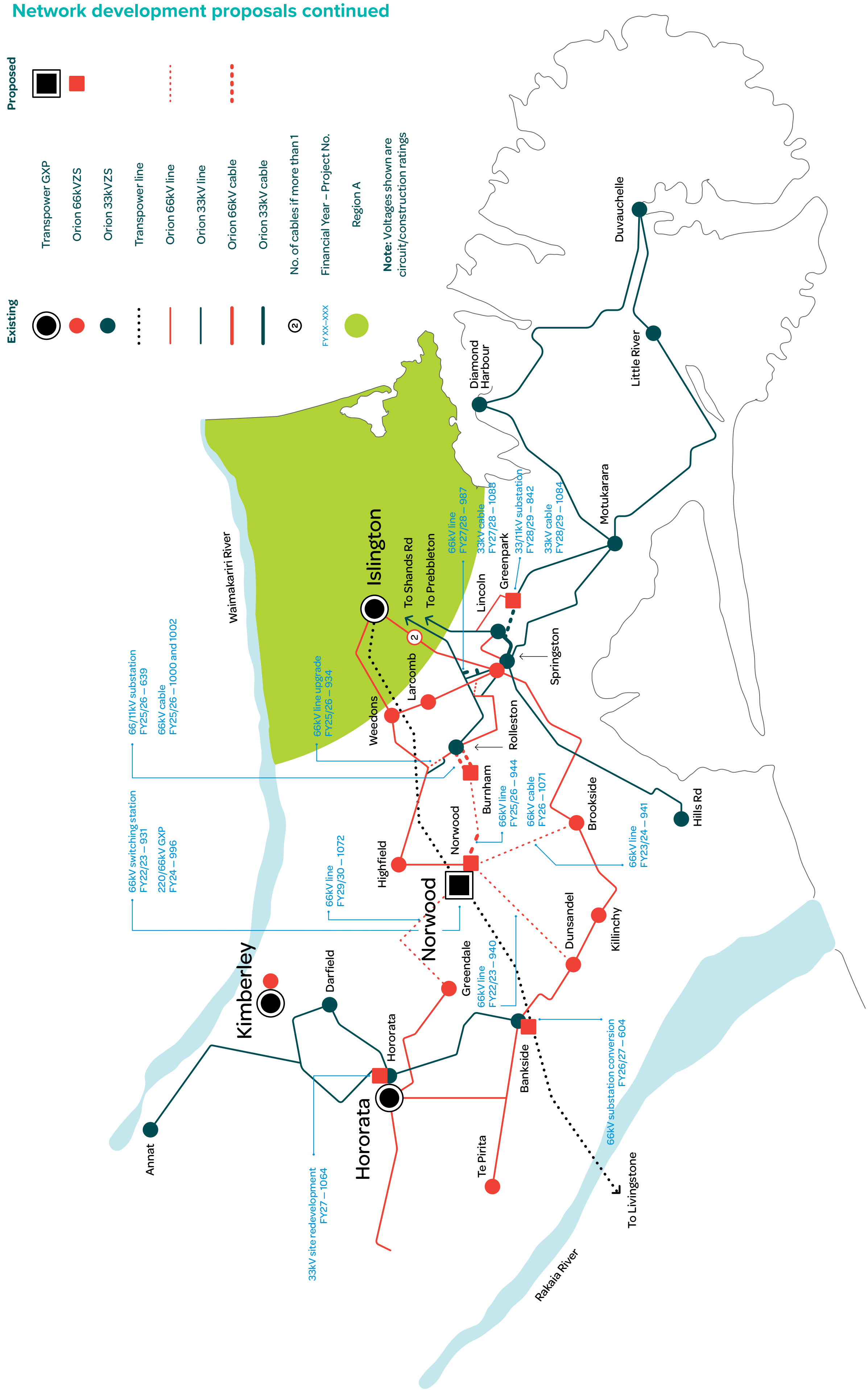
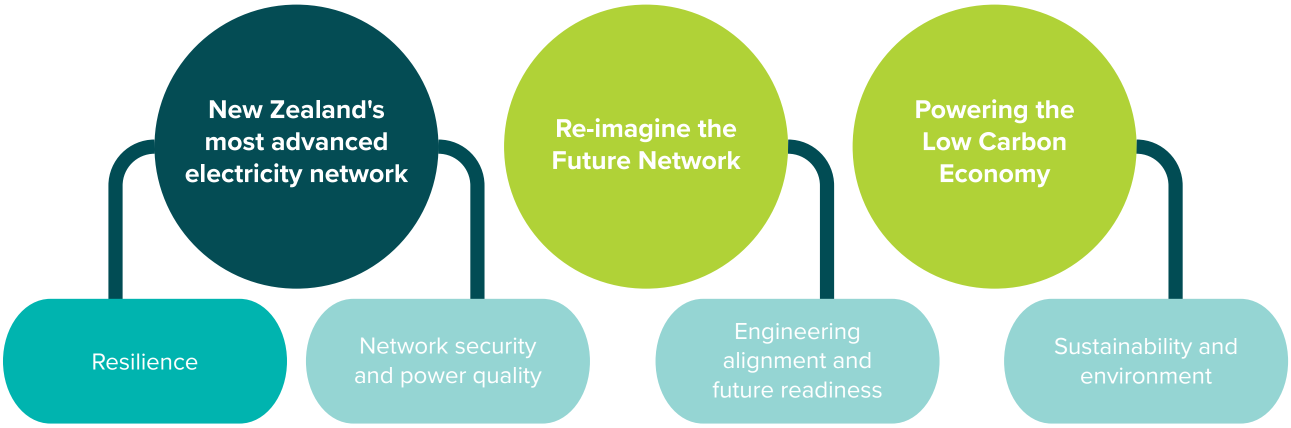


Figure 6.6.2 Region B subtransmission 66kV and 33kV – existing and proposed

6.6 Network development proposals continued

6.6.1.1 Region A 66kV subtransmission resilience

Investment drivers



To increase our urban 66kV subtransmission network's resilience against the impact of a major seismic event, we have developed a programme to replace our remaining 40km of 66kV oil filled underground cables commencing in FY23. 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.

We considered non-network solutions, however due to the capacity required at a subtransmission level these solutions are not suitable to supply base level demand. Non-network solutions are unable to provide subtransmission N-1 security, because repair times on 66kV equipment can be two weeks for joint issues. This is far beyond the energy storage capability of existing known Distributed Energy Resource (DER) systems during our winter peak load times.

This programme also replaces the legacy Region A 66kV bulk-supply point spoke-and-hub architecture with a far more resilient interconnected GXP ring architecture. The projects in this programme that fall within the 10 year plan are outlined in Table 6.6.1.

Table 6.6.1 Region A 66kV subtransmission resilience – HV major projects

No.	Project title		Year	Business case (yes/no)
723	**Milton ZS 66kV switchgear and building**		**FY23-24**	**Yes**
	Issue	The Milton ZS to Lancaster ZS 66kV cable (Project 589) will require switchgear installation at Milton ZS.		
	Chosen solution	This project is for the construction of a new 66kV switchroom, and purchase, installation and commissioning of 66kV switchgear at Milton ZS.		
	Remarks/alternatives	This switching station is located on a pivotal intersection of the proposed 66kV network. This facilitates shifting zone substations between GXPs to manage their growth constraints and provides resilience for GXP issues.		
962	**Bromley ZS to Milton ZS 66kV cable**		**FY23-24**	**Yes**
	Issue	As part of the 66kV oil filled cable replacement programme a high-level HILP analysis identified there was a need for an additional circuit out of Bromley GXP to cover for Islington 66kV GXP contingencies.		
	Chosen solution	This project is to purchase, install and commission a new 66kV cable between Bromley ZS and the new Milton ZS 66kV switchroom, Project 723.		
	Remarks/alternatives	The Bromley ZS 66kV bay for this project is the ex-Lancaster ZS feeder bay 170.		

6.6 Network development proposals continued

Table 6.6.1 Region A 66kV subtransmission resilience – HV major projects (continued)

No.	Project title		Year	Business case (yes/no)
589	**Lancaster ZS to Milton ZS 66kV cable**		**FY24-25**	**Yes**
	Issue	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.		
	Chosen solution	A new 66kV cable between Lancaster and Milton zone substations will provide extra security of supply for the CBD.		
	Remarks/alternatives	This cable link was envisaged as part of our post-earthquake 2012 subtransmission architecture review.		
665	**Hoon Hay ZS 66kV switchgear and building**		**FY25-26**	**Yes**
	Issue	Hoon Hay ZS is currently supplied via dual circuit transformer cable feeders from Halswell ZS. These cables are 66kV oil filled cables so are programmed for replacement with a new diverse route 66kV closed-ring supply from Bromley ZS. To facilitate this new architecture a 66kV switchroom is required at Hoon Hay ZS.		
	Chosen solution	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 (Project 664).		
	Remarks/alternatives	The new building will fit within the existing Hoon Hay ZS site, but further land acquisition is needed to meet building set-back requirements.		
664	**Milton ZS to Hoon Hay ZS 66kV cable**		**FY26-27**	**Yes**
	Issue	To facilitate the new Region A 66kV architecture as part of the 66kV oil filled cable replacement programme a cable connection between Milton ZS and Hoon Hay ZS is required. This addresses the existing lack of route diversity supplying Hoon Hay and mitigates the emerging constraint on the Islington – Halswell tower line.		
	Chosen solution	This project is the purchase, installation and commissioning of a new 66kV cable between the new Milton ZS 66kV switchroom (Project 723) and the new Hoon Hay ZS 66kV switchroom (Project 665).		
	Remarks/alternatives	This project has been deferred by one year, from the previous 2021 AMP, to balance the cable installation service provider resourcing.		
671	**Halswell ZS 66kV switchgear and building**		**FY26-27**	**Yes**
	Issue	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 solution	This project is the construction and commissioning of a new 66kV ring-bus and switchroom at Halswell ZS.		
	Remarks/alternatives	This project has been timed to coincide with the lifecycle replacement of four 66kV CBs at Halswell ZS and the purchase, installation and commissioning of a 3rd 11kV bus section and new 23MVA transformer (Project 919) to increase the 11kV capacity of Halswell ZS.		
726	**Halswell ZS to Hoon Hay ZS 66kV cable**		**FY26-27**	**Yes**
	Issue	Hoon Hay ZS is currently supplied via spur dual circuit 66kV oil filled cables from Halswell ZS. These cables are a seismic vulnerability and are to be replaced with a new closed-ring 66kV architecture.		
	Chosen solution	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 (Project 665).		
	Remarks/alternatives	This project will supply Hoon Hay ZS with a 66kV supply with diverse supply routes, providing full N-1 security of supply.		

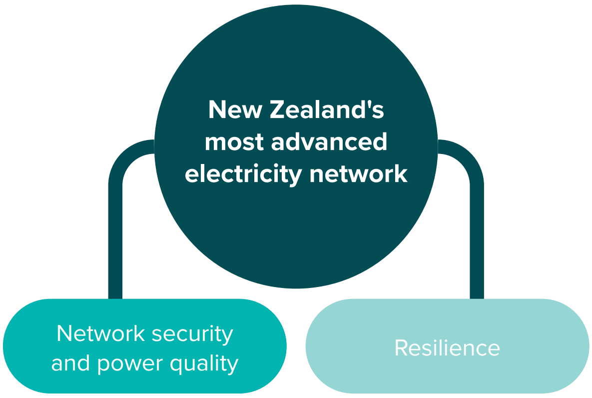
6.6 Network development proposals continued

Table 6.6.1 Region A 66kV subtransmission resilience – HV major projects (continued)

No.	Project title		Year	Business case (yes/no)
872	**Addington ZS 66kV bus coupler**		**FY26-27**	**Yes**
	Issue	Addington ZS 66kV currently operates as two separate 66kV supply points due to the lack of busbar protection or bus coupler.		
	Chosen solution	This project is the purchase, construction and commissioning of the 66kV switchgear to create a bus coupler and fit bus zone protection to the 66kV bus.		
	Remarks/alternatives	This project will enable the 66kV bus at Addington to be operated closed upon completion of the new CBD 66kV ring.		
1050	**Oxford Tuam ZS 66kV switchgear and building**		**FY27-28**	**Yes**
	Issue	The proposed replacement Region A 66kV architecture has Oxford Tuam ZS on a closed-ring supply requiring a new 66kV switching station.		
	Chosen solution	This project is the construction, installation and commissioning of a new 66kV indoor switching station on our section adjacent to the existing Oxford Tuam ZS site.		
	Remarks/alternatives	Projects 730 and 731 are the 66kV cable projects that connect this into the network.		
730	**Armagh ZS to Oxford Tuam ZS 66kV cable**		**FY28-29**	**No**
731	**Addington ZS to Oxford-Tuam ZS 66kV cable**		**FY29-30**	**No**
871	**Addington ZS to Milton ZS 66kV cable**		**FY30-31**	**No**
966	**Addington ZS to Fendalton ZS T1 66kV cable**		**FY31-32**	**No**
1264	**Addington ZS to Fendalton ZS T2 66kV cable**		**FY32-33**	**No**

6.6.1.2 Southwest Christchurch growth and resilience

Investment drivers



The southwest area of Christchurch is experiencing steady load growth due to the green-fields expansion of residential subdivisions in and around Halswell and the popularity of the Hornby industrial belt, on the fringe of Christchurch city and the Selwyn region. This is driven by the ease of access to the Southern Motorway.

The forecast load on the two main zone substations supplying these areas, Halswell and Shands Rd ZS, will exceed their capacities so this body of projects will restore network security and provide headroom for the forecast increase in electric vehicle charging during peak load times.

A secondary driver is to address the resilience of the Islington GXP 33kV supply point. Shands Rd ZS will be converted to 66kV, removing load from the 33kV system, strengthening the ability to fully restore load after a major double fault 33kV outage.

The timing of the Halswell ZS upgrade will coordinate with the Region A 66kV subtransmission resilience programme, see 6.6.1.1, ensuring that the subtransmission architecture will support the additional load.

We investigated non-traditional reinforcement using Distributed Energy Resources (DER), however the base load industrial and winter peaking loads combined with significant industrial and residential growth mean that using other sources such as generators to meet expected loads is not feasible. Diesel generation is also at odds with Orion’s commitment to reducing its carbon emissions and the rate of load growth also makes it unsuitable for grid scale battery storage. Technologies such as STATCOMs unlock thermal capacity in voltage constrained areas of the network, but do not provide real power capacity as required in the Southwest Christchurch area.

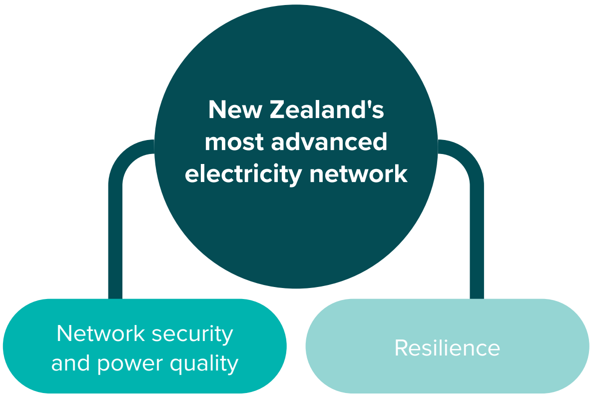
6.6 Network development proposals continued

Table 6.6.2 Southwest Christchurch growth and resilience – HV major projects

No.	Project title		Year	Business case (yes/no)
919	**Halswell ZS 3rd transformer and 11kV switchgear**		**FY26-27**	**No**
	Issue	High residential growth in the southwest of Christchurch has meant that the 11kV capacity is close to the N-1 limit between Halswell ZS and Hoon Hay ZS.		
	Chosen solution	Purchase, install and commission 3rd transformer and new 11kV switchgear for 3rd bus section. This project includes the 11kV switchroom and 23MVA transformer pad construction.		
	Remarks/alternatives	An alternative to introduce new capacity is to establish a new zone substation (Awatea), but upgrading an existing established site is much more cost effective. Upgrading Halswell to a 2x 40MVA transformer site was considered but ruled out due to the need to upgrade the existing 11kV switchgear under this option.		
669	**Shands Rd ZS site redevelopment**		**FY27-28**	**No**
	Issue	The 33kV and 11kV switchgear is due for replacement at Shands Rd ZS. The existing 33kV structure is outdoor and 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 space constrained with no ability to expand the switchboard size.		
	Chosen solution	As part of the surrounding industrial subdivision we have secured an adjacent lot to Shands Rd ZS. This project is to construct new switch-rooms to coincide with the lifecycle replacement of the 33 and 11kV switchgear. The 33kV switchroom will be constructed at 66kV insulation levels to prepare the site for conversion from 33kV to 66kV (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.		
702	**Shands Rd ZS 66kV termination poles**		**FY31-32**	**No**
708	**Shands Rd ZS 33kV to 66kV conversion**		**FY31-32**	**No**
1269	**Shands Rd ZS to Islington / Halswell ZS tower line 66kV cables**		**FY31-32**	**No**

6.6.1.3 Northern Christchurch network

Investment drivers



Presently Orion's Belfast, Dallington, Rawhiti and Waimakariri zone substations are fed on either single spur cable or open-ring 66kV supplies and have potential loads in-excess of 15MVA. These sites do not currently meet our Security of Supply criteria as they are vulnerable to complete outages for single cable faults. Belfast zone substation is also currently only equipped with a single transformer so does not provide a firm 11kV supply.

The rate of growth and the existing load at each of these sites makes generators and battery storage uneconomic as significant capacity would need to be replicated at each site. Technologies such as STATCOMs unlock thermal capacity in voltage constrained areas of the network, but do not provide real power capacity as required in the Northern Christchurch area.

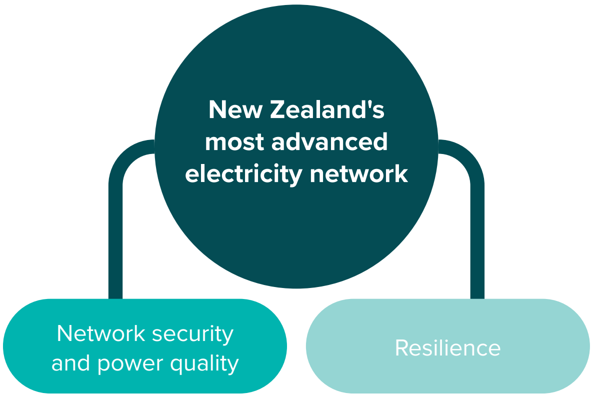
This set of projects is a continuation of our programme of works to increase the capacity, reliability and resilience of the northern Christchurch network that began in FY20.

Table 6.6.3 Northern Christchurch network – HV major projects

No.	Project title		Year	Business case (yes/no)
1174	**Belfast ZS 2nd transformer / network spare**		**FY26-27**	**No**
	Issue	There is currently no network spare for the 40MVA 66/11kV power transformers.		
	Chosen solution	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.		
491	**Belfast ZS to McFaddens ZS 66kV cable links**		**FY23-24**	**Yes**
	Issue	The supplies to Belfast ZS, Dallington ZS, Rawhiti ZS and Waimakariri ZS have only switchable N-1 security at 66kV.		
	Chosen solution	This project establishes 66kV cable links from Belfast ZS to Waimakariri ZS and from Marshland 66kV switching station to McFaddens ZS.		
	Remarks/alternatives	Belfast ZS, Dallington ZS, Rawhiti ZS and Waimakariri ZS will have full N-1 security at 66kV on completion of this cable link project.		

6.6.1.4 Region A subtransmission capacity

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. As stated in Section 6.3.5.1, Transpower GXP load forecasts, our current forecast only captures load increases where we have certainty regarding the location, size and timing of projects. Therefore, we anticipate that as more fossil-fuelled process heating is converted to electric the capacity of Islington 66kV GXP will be reached sooner. Rather than putting more dependency on Islington 66kV GXP by introducing more capacity into 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 6.6.4 enable Weedons and Larcomb ZS to be offloaded and fed from Norwood GXP by establishing new connections and increasing the capacity of others. The timing of these projects is indicative and will likely change as we gather more information about our customers plans to decarbonise.

6.6 Network development proposals continued

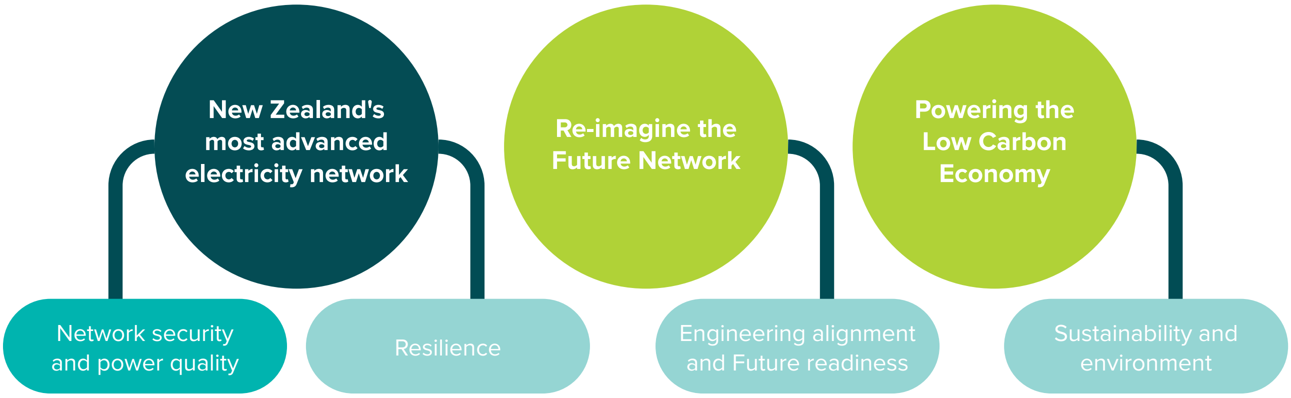
Table 6.6.4 Region A subtransmission capacity – HV major projects

No.	Project title		Year	Business case (yes/no)
987	**Lincoln Rolleston Rd 66kV line**		**FY27-28**	**No**
	Issue	The Islington 66kV GXP is forecast to exceed the N-1 capacity due to continued growth in both Region A and B.		
	Chosen solution	This project enables Larcomb and Weedons ZS to be transferred from Islington to Norwood GXP. This is achieved by utilising and extending the Burnham (ex-Rolleston) to Springston ZS 66kV constructed line from the end of Rattletrack Rd onto the Springston to Larcomb ZS 66kV line on Weedons Rd.		
	Remarks/alternatives	This line section is currently constructed at 33kV and is the most cost-effective solution to mitigate the Islington 66kV GXP loading issue.		
1088	**Weedons Rd 33kV cable**		**FY27-28**	**No**
	Issue	To maintain the 33kV support from Springston ZS to Shands ZS once Project 987 converts a section of 33kV overhead to 66kV, a new 33kV cable is required.		
	Chosen solution	The cable will be laid from the corner of Weedons Rd and Lincoln Rolleston Rd to the corner of Weedons Rd and Selwyn Rd.		
	Remarks/alternatives	Re-establishing the connection via a 33kV cable is simpler and more cost-effective solution than installing a new 66kV cable to establish the Burnham ZS to Larcomb ZS connection.		
1095	**Wards Rd 66kV line reconductor**		**FY28**	**No**
	Issue	The Norwood GXP – Highfield ZS – Burnham ZS 66kV ring is limited in its capability to carry Weedons and Larcomb ZS due to the existing overhead conductor on Wards Rd.		
	Chosen solution	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 thermal upgrade**		**FY28**	**No**
	Issue	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		
	Chosen solution	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 is far more cost-effective than reconductoring the line as this would require the entire line to be rebuilt.		

6.6 Network development proposals continued

6.6.1.5 Region B 66kV subtransmission capacity

Investment drivers



Continued residential and commercial growth around the areas of Rolleston, Lincoln and growth from major consumers will cause load on the Islington – Weedons – Larcomb – Springston 66kV (Western) Loop to exceed firm capacity around FY23. Commercial and residential load growth in the central city, Halswell, Rolleston and Lincoln as well as large industrial and commercial developments in Belfast and at Dunsandel ZS are driving the constraint.

The resilience of the subtransmission supply to Region B is currently limited by the supply at Islington 66kV, the generation from Trustpower's Lake Coleridge and the 66kV subtransmission capacity. The 66kV subtransmission circuit between Hororata and Springston has been identified as a network security gap. With the load on this circuit exceeding 15MVA, our Security of Supply Standard requires that a fault on a single cable, line or transformer causes no interruption of supply to customers which is not currently achievable.

It should also be noted that the primary supply to a major consumer from Dunsandel ZS is voltage drop and thermally constrained.

We investigated solutions to address the Islington 66kV GXP constraints such as increasing capacity at Bromley GXP and shifting some Islington GXP load to Bromley GXP. They will fix the Islington 66kV GXP issue but will not address the other issues that have been identified. Other possible sites for the new GXP were considered but were determined to be less suitable due to their location relative to the Orion subtransmission and Transpower networks as well as their distance from the areas of load growth / constraint. Distributed Energy Resources, for example solar plus batteries, are better suited to deferring investment in a slowly developing load environment. The growth rate expected in Region B means this is not a good candidate. A new GXP also supports the growth likely to come from customers switching from coal to electric boilers in Region B and the west of the city.

The chosen solution to address all these issues is to install a new 220/66kV GXP at Norwood that is supplied from the Transpower Islington-Livingstone 220kV circuit.

Projects that form the Region B 66kV subtransmission capacity programme of works are outlined in Table 6.6.5.

Table 6.6.5 Region B 66kV subtransmission capacity – GXP projects

No.	Project title		Year	Business case (yes/no)
996	**Norwood GXP - new Region B 220/66kV substation**		**FY24**	**Yes**
	Issue	The 66kV capacity supplying Region B is becoming constrained due to rapid growth in this area, with the Western Loop forecast to exceed firm capacity around FY23.		
	Chosen solution	Install a new dual transformer 220/66kV GXP at Norwood that is supplied from the Transpower Islington-Livingstone 220kV circuit.		
	Remarks/alternatives	Construction of a new Region B GXP was the most cost-effective option from the Transpower Grid Reliability Standard (GRS) assessment. Two alternative GXP locations were also considered as part of our 'Region B subtransmission options' business case. Although this project is Orion initiated, it will be constructed, owned and operated by Transpower.		

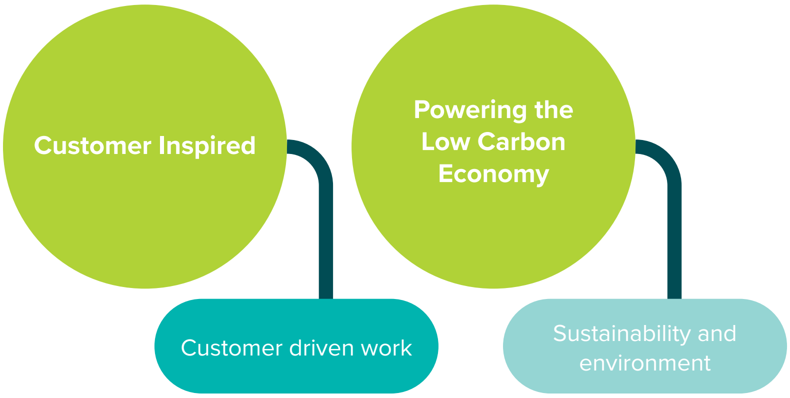
6.6 Network development proposals continued

Table 6.6.6 Region B 66kV subtransmission capacity – HV major projects

No.	Project title		Year	Business case (yes/no)
931	**Norwood ZS 66kV**		**FY22-23**	**Yes**
	Issue	The 66kV capacity supplying Region B is becoming constrained due to rapid growth in this area, with the Western Loop forecast to exceed firm capacity around FY23.		
	Chosen solution	Construct a new outdoor 66kV busbar to take bulk supply from the new Norwood GXP (Project 996).		
	Remarks/alternatives	We investigated constructing an indoor busbar similar to our Region A 66kV switching stations, but for this application it is significantly more cost-effective to build an outdoor yard (~30% less).		
940	**Dunsandel ZS to Norwood ZS 66kV line**		**FY22-23**	**Yes**
	Issue	The existing 66kV subtransmission network supplying Dunsandel ZS has no capacity available for any additional load growth.		
	Chosen solution	This project provides a direct 66kV connection between the new Norwood GXP (Project 931) and Dunsandel ZS.		
	Remarks/alternatives	This project forms one leg of the full N-1 66kV ring supply to Dunsandel ZS, refer to Project 941 for the Norwood – Brookside ZS 66kV line.		
946	**Dunsandel ZS 66kV line bay**		**FY22-23**	**Yes**
	Issue	A new 66kV CB bay is required at Dunsandel ZS to terminate the new 66kV line from Norwood ZS (Project 940).		
	Chosen solution	The existing 66kV ring-bus at Dunsandel ZS was originally designed and constructed for additional 66kV bays to be added. This project is the purchase, construction and commissioning of a new 66kV bay to terminate the new 66kV line from Norwood ZS.		
	Remarks/alternatives	Refer to Project 931 for the construction of the 66kV busbar at Norwood ZS.		
941	**Brookside ZS to Norwood ZS 66kV line**		**FY23-24**	**Yes**
	Issue	Dunsandel ZS load has grown beyond the N-1 capability of the existing subtransmission network so an additional 66kV supply from Norwood ZS is required.		
	Chosen solution	This project provides a 66kV connection between Norwood ZS (Project 931) and Brookside ZS provides an uninterrupted N-1 supply to Dunsandel ZS and Killinchy ZS. The new line will tee into the existing Brookside ZS to Killinchy ZS 66kV line so no additional 66kV CB bay will be required at Brookside ZS.		
	Remarks/alternatives	An alternative would be to double circuit the direct Norwood ZS to Dunsandel ZS 66kV line, but the chosen arrangement provides greater resilience through route diversity.		

6.6.1.6 Customer driven projects

Investment drivers



The customer driven projects in Table 6.6.7 are large connections requiring subtransmission or zone substation capacity upgrades. All these customer driven projects support our customers in reducing New Zealand's carbon footprint.

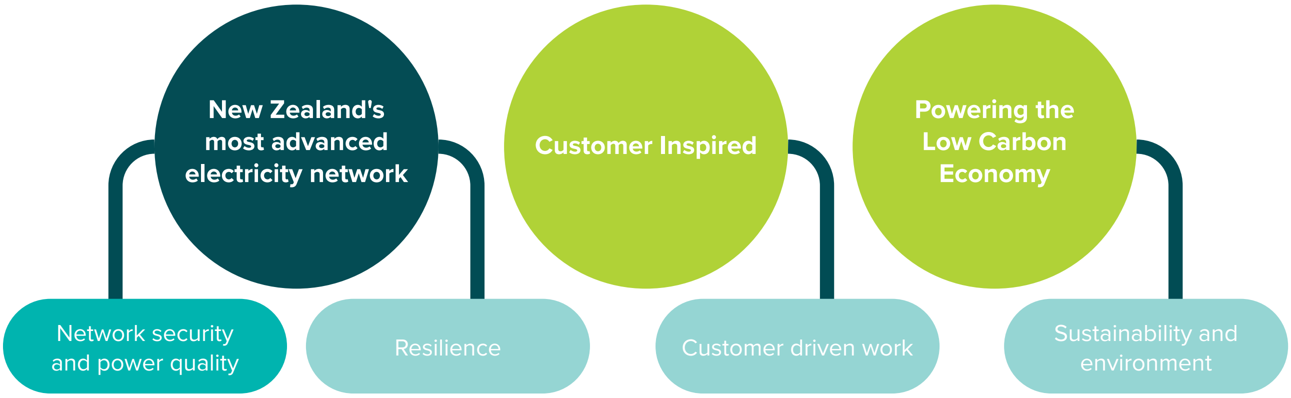
6.6 Network development proposals continued

Table 6.6.7 Customer driven projects – HV major projects

No.	Project title		Year	Business case (yes/no)
1237	**Brookside ZS upgrade (stage 1)**		**FY22-23**	**Yes**
	Issue	A customer connection adjacent to the Brookside ZS requires a large capacity 11kV connection, but there are no spare 11kV switches available.		
	Chosen solution	The connection capacity requires an additional 11kV circuit breaker to be added to the 11kV switchboard at Brookside ZS to facilitate the connection while simplifying the metering requirements.		
	Remarks/alternatives	Other associated works are required to enable space for the extension to occur.		
1266 1267	**Brookside ZS upgrade (stages 2 and 3)**		**FY23-25**	**Yes**
	Issue	The proposed Stage 2 and 3 of a customer development exceeds the capability of the existing power transformer at Brookside ZS.		
	Chosen solution	We propose to expand the Brookside ZS 66kV switchyard to provide the Stage 2 and 3 connections via two new power transformers.		
	Remarks/alternatives	These projects facilitate the connection of the new Norwood to Brookside ZS 66kV line (Project 941) into a separate 66kV bay. Stage 2 will utilise the unused capacity of the Springston ZS to Brookside ZS 66kV line upon completion of Norwood GXP.		
1275	**Dunsandel ZS 66kV tee-off**		**FY24-25**	**Yes**
	Issue	A customer requires a large capacity connection, but the existing 11kV distribution has limited capacity.		
	Chosen solution	The customer will be connected at 66kV via a new tee-off from the Dunsandel ZS to Norwood ZS 66kV line.		
	Remarks/alternatives	The overall solution may incorporate a future stage connection to a remote site. This future stage will require additional cabling. The timing of these projects is tentative and is dependent on the customer.		
1070	**Norwood 66/11kV zone substation**		**FY24-25**	**Yes**
	Issue	An existing major customer is increasing their load beyond the existing 11kV distribution capacity between Highfield ZS, Rolleston ZS and Greendale ZS. After the completion of Burnham ZS (Project 639) the Highfield ZS to Norwood ZS 66kV line (Project 943) will be required to operate at 66kV to create an N-1 supply for Highfield ZS and Burnham ZS. This means it can no longer be used for the 11kV supply to customer/s.		
	Chosen solution	The chosen solution is to construct an 11kV point of supply at Norwood ZS (Project 931) by installing a 66/11kV transformer and 11kV switchboard at the Norwood site to feed in to the surrounding 11kV network.		
	Remarks/alternatives	A large contributor to the major customer load increase is the conversion of coal to electric heat pump process heating.		

6.6.1.7 Lincoln area capacity and resilience improvement

Investment drivers



High residential subdivision growth in the Lincoln township has pushed the peak load of Lincoln ZS beyond the firm capacity by approximately 0.5MVA.

By FY31 this load is forecast to be approximately 130% of the site's firm capacity. Springston ZS also provides support for the Lincoln township and due to the additional commercial growth, is forecast to breach its capacity in FY24. If unaddressed, this situation puts the area at risk of a cascade failure, black-out fault, during peak load times.

We considered non-network alternatives but Distributed Energy Resources, for example solar, are better suited to deferring investment in a slowly developing load environment. The growth rate expected in the Lincoln area and the winter peaking aspect means it is not a good candidate.

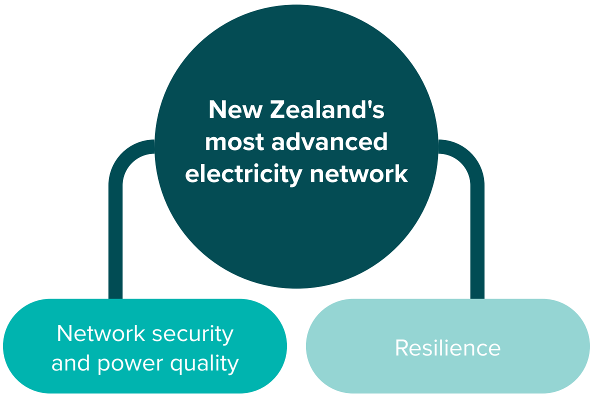
The projects in Table 6.6.8 address the short to medium term issues with upgrades to Springston ZS. The Lincoln township is growing away from both Springston and Lincoln ZS so in the longer-term a new Greenpark zone substation is forecast to be built on the eastern side of the township. The programme also incorporates various subtransmission enabling projects to reinforce the network into Greenpark ZS.

Table 6.6.8 Lincoln area capacity and resilience improvement – HV major projects

No.	Project title		Year	Business case (yes/no)
1235	**Birchs Rd 33kV overhead reconductor**		**FY23**	**Yes**
	Issue	The overhead line on Birchs Rd limits the capacity to the proposed new Greenpark ZS.		
	Chosen solution	Reconductor the existing 33kV OH from the Lincoln ZS end to Tancreds and Birchs Rd corner.		
	Remarks/alternatives	This is a low-cost solution to meet the capacity needs for Greenpark ZS and defers the need to construct the Tancreds and Springs Rd 66kV line (Project 1081) until Greenpark ZS is converted from 33kV to 66kV.		
728	**Springston ZS 11kV switchboard extension**		**FY23-24**	**Yes**
	Issue	At Springston ZS additional 11kV circuit breakers are required to connect the new 66/11kV transformer (Project 894).		
	Chosen solution	This project extends the 11kV CB's installed in FY18 to terminate the new transformer and provide additional feeders.		
	Remarks/alternatives	The 11kV CBs located within the modular building will be decommissioned as part of this project.		
894	**Springston ZS 2nd 66/11kV transformer bank**		**FY23-24**	**Yes**
	Issue	The excess capacity available at Springston ZS to provide contingency support to the neighbouring Lincoln, Rolleston and Brookside zone substations is diminishing due to sustained residential household and the university growth. Lincoln ZS and Springston ZS provide support for each other during major N-1 events, but by FY26 the total load of these substations is forecast to be in-excess of their combined N-1 rating (20MVA).		
	Chosen solution	We will increase the capacity by installing a second 66/11kV transformer and additional 66kV CB bay.		
	Remarks/alternatives	Upgrading the Lincoln ZS transformers is not practical and the addition of the second bank at Springston ZS upgrade defers the immediate need to construct the Greenpark substation.		
1099	**Springston ZS 66/11kV transformer upgrade**		**FY24-25**	**Yes**
	Issue	In FY24 a second 66/11kV transformer will be added to Springston ZS, but this won't provide any usable increase in firm capacity due to the original transformer bank being only 10MVA in size. The load at Lincoln University and Lincoln township has exceeded the N-1 capacity.		
	Chosen solution	Change the existing T3 66/11kV 10MVA transformer to a new 11.5/23MVA transformer.		
	Remarks/alternatives	This upgrade defers the need to construct the Greenpark substation.		
1080	**Springston to Lincoln ZS 66kV line reconductor**		**FY27**	**No**
	Issue	An existing 33kV operated overhead section, constructed on Shands and Boundary Rd's, from Springston ZS to Lincoln ZS does not have sufficient capacity to supply Greenpark ZS (Project 842).		
	Chosen solution	Reconductor the line to a higher capacity conductor.		
	Remarks/alternatives	This pole line has already been rebuilt to 66kV construction as part of an asset lifecycle refurbishment project.		
1084	**Edward St to Greenpark ZS 33kV cable**		**FY28-29**	**No**
842	**Greenpark 33kV zone substation**		**FY28-29**	**No**

6.6.1.8 Rolleston area capacity and resilience

Investment drivers



The Rolleston area has experienced rapid load growth due to the township residential and industrial subdivision growth. This growth has pushed the Rolleston ZS beyond its firm capacity and most practical 11kV load transfers to the supporting substations of Larcomb and Weedons ZS have been exhausted.

This programme of works addresses the local 11kV distribution capacity with the establishment of a new higher capacity substation to replace Rolleston ZS.

The programme of works also outlines the projects that develop the 66kV diverse route subtransmission closed-loop supply from Norwood ZS to the new substation. Options to supply the new substation from either the existing 33kV network or reinsulating the remaining 33kV to 66kV lines to complete the ring fed from Weedons and Springston ZS were investigated, but they do not address the impending 66kV subtransmission constraint on the Western Loop.

The first leg of the 66kV loop has already commenced with the construction of the Norwood ZS to Highfield ZS 66kV insulated line in FY22.

Table 6.6.9 Rolleston area capacity and resilience – HV major projects

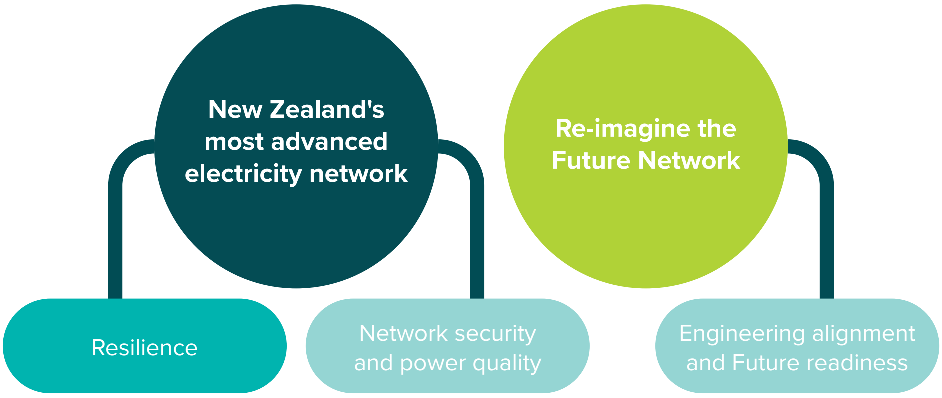
No.	Project title		Year	Business case (yes/no)
934	**Walkers Rd 66kV line conversion**		**FY25-26**	**No**
	Issue	The overhead 33kV conductor between Highfield ZS and Rolleston ZS has progressively been upgraded to 66kV construction in anticipation of operation at 66kV. However, there is a small section remaining down Walkers Rd that has yet to be upgraded.		
	Chosen solution	This project converts the remaining 33kV line construction, down Walkers Rd, between Two Chain Rd and Kerrs/Wards Rd, to 66kV construction.		
	Remarks/alternatives	This project coordinates with other projects to meet the requirement of creating a 66kV ring out of Norwood ZS to supply the new Burnham ZS.		
953	**Norwood ZS 66kV line bays**		**FY25-26**	**No**
	Issue	66kV bays at Norwood 66kV need to be equipped to enable connection and supply of the Burnham ZS to Highfield ZS 66kV ring.		
	Chosen solution	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, Burnham ZS and a bay for a 66/11kV transformer (Project 1070).		
	Remarks/alternatives	Although not required till FY26, the timing of this project is to ensure the resource required to construct the final solution is smoothed-out over several years.		

Table 6.6.9 Rolleston area capacity and resiliency – HV major projects (continued)

No.	Project title		Year	Business case (yes/no)
954	**Highfield ZS 66kV line bays**		**FY25-26**	**No**
	Issue	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.		
	Chosen solution	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 originally designed with future expansion to three 66kV CB's, but constructed with one.		
639	**Burnham ZS – new 66/11kV substation**		**FY25-26**	**No**
	Issue	The load growth in the Rolleston/Izone area has caused the 11kV firm capacity of Rolleston ZS to be exceeded and the upper network capacity is also reaching the firm capacity (Projects 931 and 944).		
	Chosen solution	A new 66/11kV 23MVA capacity Burnham ZS will be built to replace the 33/11kV 10MVA capacity at Rolleston ZS. The 11kV switchboard will be located at Rolleston ZS supplied via 11kV incomers from Burnham ZS.		
	Remarks/alternatives	Upgrading Rolleston ZS to 23MVA utilising the existing 33kV supply was investigated but was found to be unsuitable due to space constraints. This project also shifts load off the Islington 66kV GXP onto the new Norwood GXP relieving the upper network capacity.		
944 1071	**Burnham ZS to Norwood ZS 66kV circuit**		**FY25-26**	**No**
	Issue	A full N-1 66kV supply from Norwood ZS is required for Burnham ZS.		
	Chosen solution	These projects form a direct link from Norwood ZS to Burnham ZS via a 66kV cable out of Norwood ZS (Project 1071) and extended onto Burnham ZS with a new 66kV line (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. Supplying the new Burnham ZS from Springston ZS at 33kV or the Islington GXP were investigated, but these solutions do not provide the same additional resiliency or capacity benefits. Part of the 66kV line is partially formed as part of a supply upgrade project for the Burnham military camp.		
1000	**Burnham ZS to Dunns Crossing Rd north 66kV cable**		**FY25-26**	**No**
	Issue	The area surrounding the proposed Burnham 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 Burnham ZS to provide a N-1 supply.		
	Chosen solution	This project is a new 66kV cable circuit to connect the new Burnham ZS onto the O/H line running down Dunns Crossing Rd to provide part of the connection back to Norwood ZS via Highfield ZS.		
	Remarks/alternatives	An overhead line option was considered but is not suitable due to the proximity of the school and houses.		
1002	**Burnham ZS to Dunns Crossing Rd south 66kV cable**		**FY25-26**	**No**
	Issue	A second 66kV circuit heading east out of Burnham ZS is required to connect to the 66kV overhead line heading south down Dunns Crossing Rd.		
	Chosen solution	This project is the installation and commissioning of a new 66kV cable down Burnham School Rd from Burnham ZS to Dunns Crossing Rd to enable Larcomb and Weedons ZS to be supplied from Norwood GXP and includes the overhead line termination pole.		
	Remarks/alternatives	This project has been brought forward from FY29/30 to align with the construction of Burnham ZS to benefit from installation efficiencies.		

6.6.1.9 Hororata GXP capacity and resilience

Investment drivers



The Hororata 33kV GXP has reached the firm capacity due to the 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. Therefore, any reduction of load will benefit the overall post-contingency voltage stability. This GXP does not have a 66kV bus coupler either so is exposed to single bus faults causing complete outages to the 66kV and 33kV Orion load and the connection through to Coleridge GXP.

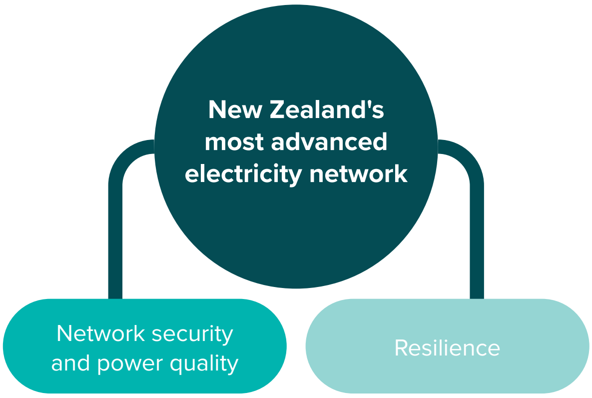
The projects in Table 6.6.10 reduce the Hororata 33kV GXP load and create a new 66kV connection to Norwood GXP increasing the resilience of Greendale ZS.

Table 6.6.10 Hororata GXP capacity and resilience – HV major projects

No.	Project title		Year	Business case (yes/no)
604	**Bankside ZS 33kV to 66kV conversion**		**FY26-27**	**No**
	Issue	The Hororata 33kV load has reached the Hororata 33kV GXP N-1 capacity at summer peak load periods putting greater than 23MVA at risk of cascade failure if a single transformer fault was to occur.		
	Chosen solution	Convert Bankside to 66kV by replacing existing 33/11kV transformer with a 66/11kV 10MVA transformer. Two new 66kV bays and a line diversion will connect Bankside into the Dunsandel ZS to Te Pirita/Hororata ZS 66kV line.		
	Remarks/alternatives	Options to relieve the 33kV constraint via 11kV load transfers have been exhausted and further shifts would significantly affect the 11kV reliability due to excessively large feeders. This project should be completed before proceeding with the 33kV switchgear replacement at Hororata ZS, see Project 1064.		
1064	**Hororata ZS 33kV site redevelopment**		**FY27**	**No**
	Issue	The present Orion Hororata ZS is a combination of the ex-Central Canterbury Power Board and ex-Transpower assets spread across two switchyards. All seven bays of switchgear are due for replacement and the existing bus layout does not meet current design standards or operator safety clearances.		
	Chosen solution	This solution rationalises the assets from the two 33kV sites into a new site. The new bus will be constructed at a 66kV insulation level to prepare the site for a future connection to Norwood ZS.		
	Remarks/alternatives	A prerequisite for this project is that Bankside ZS has been converted from 33kV to 66kV, see Project 604. This negates the need for an additional switchgear bay on the new Hororata bus.		
1072	**Norwood ZS to Greendale ZS 66kV line**		**FY29-30**	**No**
1086	**Norwood ZS 66kV line bay for Greendale ZS**		**FY29-30**	**No**
1087	**Greendale ZS 66kV bays**		**FY29-30**	**No**

6.6.1.10 Distribution network reinforcement projects

Investment drivers



This set of projects are reconfigurations or reinforcements of the 11kV distribution system across the Orion network. These are identified through our ongoing monitoring of 11kV feeder loadings and regular review of our zone substation contingency plans.

Table 6.6.11 Distribution network reinforcement projects – HV minor projects

No.	Project title		Year	Business case (yes/no)
1055	**Papanui 11kV primary reconfiguration**		**FY23**	**Yes**
	Issue	The network in the north of Christchurch is supplied from Papanui ZS via an 11kV primary feeder group with six feeders operating in parallel. To ensure safety is maintained for all faults on the 11kV primary feeder group, a multi-feeder protection scheme has been installed at Papanui ZS. The resilience of this network is poor because any downstream busbar, CB or relay failure will result in a loss of supply to all six feeders.		
	Chosen solution	With the completion of Belfast ZS there is now an opportunity to reconfigure the six-feeder primary. The proposed works splits the lower part of the six-feeder primary into two three feeder primaries. This rearrangement, including the unloading of the top of the primary feeder onto Belfast ZS, greatly reduces the quantity of customers exposed to an outage caused by a failure of a downstream component.		
	Remarks/alternatives	This work increases the resiliency of the feeder group and increases the reliability to Grampian St substation. This project will be completed in-conjunction with 11kV switchgear replacements at Grimseys Rd. No.187 and Grampian St No.62		
1118	**Selwyn St 11kV reinforcement**		**FY23**	**Yes**
	Issue	The secondary network on Selwyn St in Spreydon is at capacity due to the current network configuration.		
	Chosen solution	Reconfigure and reinforce the secondary network between Redruth Av and Selwyn St No.226 substations.		
	Remarks/alternatives	Shifting load with open point changes was explored but did not fix the underlying capacity issue in the area.		

6.6 Network development proposals continued

Table 6.6.11 Distribution network reinforcement projects – HV minor projects (continued)

No.	Project title		Year	Business case (yes/no)
1229	**Maunsell St E reinforcement**		**FY23**	**Yes**
	Issue	Over the past year there have been several requests submitted for new or upgraded commercial and industrial developments on the Heathcote ZS primary ring supplying the area in and around Hillsborough and Woolston. Due to an imbalance in the sharing of the load on the three legs of the ring the increase in load will cause the N-1 rating to be exceeded.		
	Chosen solution	This project will reduce the imbalance on the primary ring by creating an 11kV tie point at Maunsell St E substation and swapping some cables around outside of Chapmans Rd N substation		
	Remarks/alternatives	The other options are either more costly over the long term or do not provide enough N-1 capacity to meet the forecast growth.		
1242	**Prebbleton 11kV feeder reinforcement**		**FY23**	**Yes**
	Issue	The observed load on the main Prebbleton residential feeder, which supplies over half of the Prebbleton ZS load, reached ~65% loading during the winter 2020 peak. With the growth planned and approved for the next couple of years this loading is expected to reach ~90% which does not allow much headroom for additional growth.		
	Chosen solution	This project will install new 11kV cable between Prebbleton ZS and Farthing Dr No.71 to create a new feeder. This will allow for the main Prebbleton residential feeder to be offloaded providing headroom for future growth and reducing the number of customers at risk from a single fault.		
	Remarks/alternatives	The other options considered were more costly and could lose efficiency if not coordinated with future subdivision works.		
913	**Heathcote Lyttelton reconfiguration**		**FY24**	**Yes**
	Issue	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.		
	Chosen solution	This project is to 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.		
1093	**Innovation Dr 11kV reconfiguration**		**FY24**	**No**
	Issue	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 Moffett St ZS and Shands Rd ZS. Part of original distribution design for the area no longer matches the trunk feeder architecture due to changes in customer requirements.		
	Chosen solution	This project will change around 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 solution to provide capacity for the future commercial and industrial growth in the area.		

6.6.2 LV programmes of work

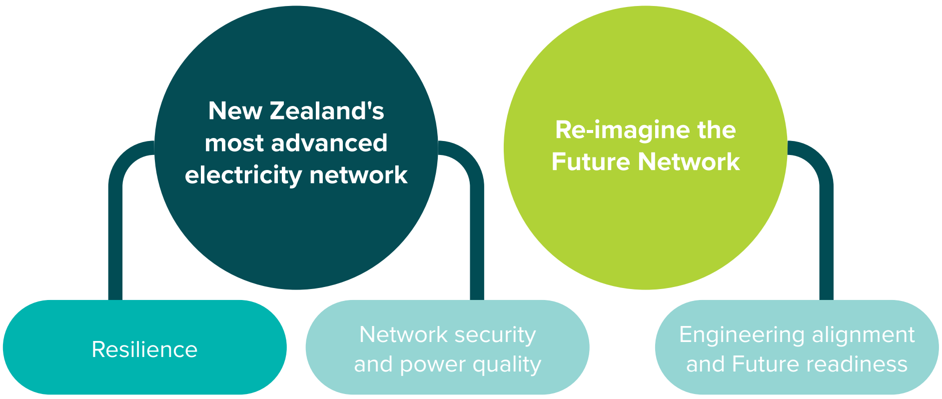
The following section outlines our Network Development LV projects and programmes of work planned for the next 10 years. With ongoing residential infill in Christchurch city as well as new technologies such as electric vehicles and photovoltaic generation becoming more economical, the capability of our LV network is becoming increasingly important. To prepare for the future and help to facilitate customer choice, we are focussing on gaining more visibility of how our LV networks are being utilised and reinforcing vulnerable areas of our LV network.

There are two main programmes of work scheduled in the 10-year period:

- LV monitoring, Section 6.6.2.1
- Proactive LV reinforcement, Section 6.6.2.2

6.6.2.1 LV monitoring

Investment drivers



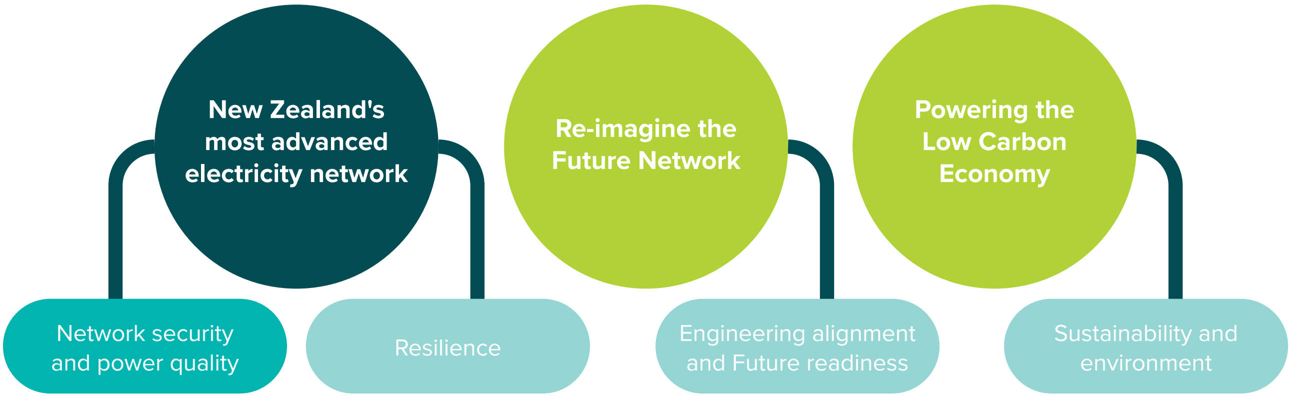
To increase the visibility and understanding of our LV networks, we aim to install approximately 1,600 LV monitors by FY26. These monitors will be targeted towards sites with a higher risk of constraint, as forecast by the research we have completed with the EPECentre. This number of monitors approximates to 13% of the total number of transformers on the network, and therefore aligns with the 'expansion scenario' described by Sapere Consulting in their 'Low Voltage Monitoring' guideline document produced for the Electricity Networks Association (ENA) in 2020.

Table 6.6.12 LV monitoring

No.	Project title		Year	Business case (yes/no)
884	**Low voltage monitoring programme**		**FY20-26**	**Yes**
	Issue	New technologies such as photovoltaic (solar) 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 solution	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.		

6.6.2.2 Proactive LV reinforcement

Investment drivers



LV network issues are not easy to identify due to high volume, low visibility and data gaps which make it difficult to model on a regular basis. Using the results of our LV research, we formulated a threshold-based system to classify LV constraints into low, medium, and high priority. It is envisaged that LV constraints will be investigated in detail on a targeted area by area basis, in order to develop project scopes for each reinforcement. During these investigations, model results will be further verified using LV monitoring data, where available, and other techniques before network upgrades are initiated.

Table 6.6.13 Proactive LV reinforcement

No.	Project title		Year	Business case (yes/no)
1277	**Proactive LV reinforcement programme**		**FY23-30**	**Yes**
	Issue	Modelling of the LV network indicates that there are several constraints existing which will be exacerbated by EV load and housing infill.		
	Chosen solution	Investigate issues and initiate proactive reinforcements to reinforce areas of the network which have been identified as constrained.		
	Remarks/alternatives	Where possible, non-network solutions will be implemented, such as network switching, phase balancing and voltage support. The feasibility of these solutions will be determined on a case by case basis.		

The top five constrained areas to be investigated are listed in Table 6.6.14.

Table 6.6.14 Top five constrained areas

Rank	Area (by number of constraints)
1	**Rawhiti**
2	**Somerfield East**
3	**Christchurch Central**
4	**Hornby Central**
5	**Bexley**

6.7 Value of Distributed Energy Resources Management alternatives

Distributed Energy Resources Management (DERM) initiatives can provide alternatives to investment in traditional network development solutions. This section is included in our AMP to assist potential DERM providers to determine the approximate funding available from Orion when specific projects are deferred through DERM.

Table 6.7.1 is a high-level assessment of the annual per kW cost of proposed network solutions where DERM could be used to defer the project. If a DERM solution is presented, further detailed analysis is undertaken to compare options.

For example:

Burnham zone substation provides capacity for a 1300kW security breach and 300kW of annual load growth. For a DERM solution to be economic it needs to provide at least one-year deferral of a network solution, and the cost per kW must be lower than $ listed below. If the DERM solution can provide three years of deferral (2.2MW at peak) then the DERM proposal cost must be lower than:

- $680/kW for 1.6MW in the first year
- $450/kW for 1.9MW in the second year
- $400/kW for 2.2MW in the third year

The values in Table 6.7.1 assume that the Distributed Energy Resources Management solution is provided in the year required.

Distributed Energy Resources Management (DERM) initiatives can provide alternatives to investment in traditional network development solutions.

Table 6.7.1 Distributed Energy Resources Management value for network development alternatives

No.	Project description	Year	Base constraint (kW)	Growth per year (kW)	$ per kW available for DERM		
					Year 1	Year 2	Year 3
1070	Norwood 66/11kV zone substation	FY24	2200	–	70	70	70
639	Burnham 66/11kV zone substation	FY25	1300	300	680	450	400
919	Halswell ZS 3rd transformer and 11kV switchgear	FY26	–	700	310	160	100
842	Greenpark 33/11kV zone substation	FY28	–	300	3450	1730	1150
1080	Springston to Lincoln 66kV line reconductor for Greenpark						
1084	Edward St to Greenpark 33kV cable						
708	Shands zone substation conversion to 66kV	FY31	–	800	1330	670	440
702	Shands 66kV termination poles						
1269	Shands cables to Islington/Halswell line						

7 Managing our assets

Photo: Orion's Hawthornden substation.

Contents

Contents continued

7.1 Introduction

We take a whole of life approach to managing our assets. In the process we develop maintenance plans and replacement plans which are discussed in Section 5.6.

The price quality trade-off is important when developing our forward works programme. We have engaged with our customers in a number of forums, see Section 4, and the consensus is that they are satisfied with our current levels of network performance.

Orion has taken a proactive approach to managing our assets with our maintenance and replacement programmes. We believe a planned approach is in the long-term interest of our customers as it minimises outages, addresses assets on a risk basis and is more cost effective. A secondary advantage is that a consistent flow of work maintains the competencies of our people and service providers which means our customers benefit during adverse events through the quality and timeliness of emergency repairs.

Replacement programmes for our poles and switchgear assets dominate our capital expenditure forecast.

The driver for these programmes is to continue addressing the potential safety consequences of asset failure.

Events that materially impact our network are weather events, vegetation and plant failure for example cable, insulator and conductor tail failure. We reduce the impact of these events by conducting regular proactive programmes where approximately 70% of our network operational expenditure is spent on inspections, maintenance and vegetation management. The remaining 30% is spent on responding to service interruptions and emergencies, the majority of which occur on our overhead network and are largely weather related.

With the exception of our new pole inspection process, our assumptions listed in Section 2.13 mean we do not expect an upswing in our inspection / monitoring programmes' expenditure. We expect the forecast expenditure for our maintenance and replacement strategies will maintain our overall performance at the current level without compromising important safety outcomes.

7.2 How this section is structured

In the following Sections 7.3 to 7.20 for each asset class we have taken a consistent approach to describing the assets, their current health, our plans for inspection, maintenance and replacement and any innovations that we are considering.

For each asset class we provide:

Summary

A summary of the current state, 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 will also be provided together with the age profile. Information on asset data management can be found in Section 2.12.2.

Asset Health

Condition

The health of an asset which considers the asset's current condition including its Health Index (HI) profile. An age profile is provided if not already outlined in the asset description. We use the CBRM models to calculate the HI and Probability of Failure (PoF) of each individual asset. The CBRM process is described in Section 5.6.

Reliability

We look at the performance of the asset class, in relation to 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' 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 major work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity. We also briefly outline the options we explore in optimising the replacement work if they are additional to those described in Section 5.6.2. 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.

Innovation

We outline innovations we are trialling which may be implemented if found to improve our current lifecycle asset management practices. This section is only provided for asset classes where it is relevant.

This section covers more than 11,900 buildings, substations, kiosks and land assets that form an integral part of Orion's distribution network.

7.3 Network property

7.3.1 Summary

This section covers more than 11,900 buildings, substations, kiosks and land assets that form an integral part of Orion's distribution network. Our distribution substation buildings vary in both construction and age. Around 150 of our substations are incorporated in a larger building that is often customer owned.

7.3.2 Asset description

7.3.2.1 Zone substation

A zone substation is a site housing high voltage infrastructure that is an important hub in our network.

It includes buildings, switchgear, transformers, protection and control equipment used for the transformation and distribution of electricity. Orion's zone substations, see Table 7.3.1, generally include a site where one of the following takes place: voltage transformation of 66kV or 33kV to 11kV, two or more incoming 11kV feeders are redistributed or a ripple injection plant is installed.

Table 7.3.1 Zone substation description and quantity

Voltage	Quantity	Description
66kV	1	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	27	Of the 27 there are 18 in Region A. 9 of those are urban substations and have an exposed bus structure. The Armagh, Dallington, Lancaster, McFaddens and Waimakariri structures are inside a building. 9 in Region B are supplied by overhead lines (Brookside, Dunsandel, Highfield, Killinchy, Larcomb, Kimberley, Greendale, Te Pirita and Weedons). All 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. Capacity of these substations is split into three groups as follows: • Larger urban substations have two or three independent dual rated transformers • Smaller urban and larger rural substations have a pair of single rated transformers • Smaller rural substations have one single rated transformer Zone substations at Annat, Bankside and Little River have 66kV structures but are currently operating at 33kV
11kV	4	These are all in Region A. They are directly supplied by either three or four radial 11kV cables and do not have power transformers. None of the 11kV zone substations have any form of outdoor structure or bus-work. We have had the opportunity to decommission some 11kV zone substations rather than replace them due to the changing load profile in certain parts of the network
Total	**50**	

7.3.2.2 Distribution substation

The different types of our distribution substations are shown in Table 7.3.2. Where our equipment is housed in buildings, many of these are owned by our customers.

Table 7.3.2 Distribution substation type

Type	Quantity	Description
Customer building	206	Customer substations are typically Orion substations contained within a customer's building. They usually contain at least one transformer with an 11kV switch unit and 400V distribution panel. There may also be 11kV circuit breakers or ring main units
Orion building	251	Orion owned substation buildings are normally stand-alone buildings. They vary in size and construction
Kiosk	3,235	Our kiosks are constructed of steel to our own design and manufactured locally. The majority fall into two categories; an older high style, and the current low style. Full kiosks vary in size and construction but usually contain a transformer with an 11kV switch unit and a 400V distribution panel
Outdoor	841	These vary in configuration, but usually consist of a half-kiosk with 11kV switchgear and a 400V distribution panel as per a full kiosk. An outdoor transformer is mounted on a concrete pad at the rear or to the side of the kiosk
Pole	6,404	Single pole mounted substations usually with 11kV fusing and a transformer
Pad transformer	831	These are a transformer only, mounted on a concrete pad and supplied by high voltage cable from switchgear at another site. Transformers are generally uncovered
Switchgear cabinet	184	Cabinets that contain only 11kV switchgear
Totals	**11,952**	

7.3.3 Asset health

7.3.3.1 Condition

Our zone substation buildings are well designed and mostly constructed with reinforced and concrete filled blocks.

Prior to the Canterbury earthquakes in 2010 and 2011 we undertook a 15-year programme to seismically strengthen our zone and distribution substation buildings. We completed the programme before the Canterbury earthquakes and recognised an almost immediate benefit for our community.

Our kiosks are generally in reasonable condition. Steel kiosks in the eastern suburbs nearer the sea are more prone to corrosion and we will replace these kiosks much sooner than those in the remainder of our network. We attend to these kiosks as needed, based on information from our condition surveys, and we now have a stainless-steel design option to guard against corrosion. The age profiles are shown in Figures 7.3.1 and 7.3.2.

Steel kiosks in the eastern suburbs nearer the sea are more prone to corrosion and we will replace these kiosks much sooner than those in the remainder of our network.

Figure 7.3.1 Substation buildings age profile by zone substation and distribution substation

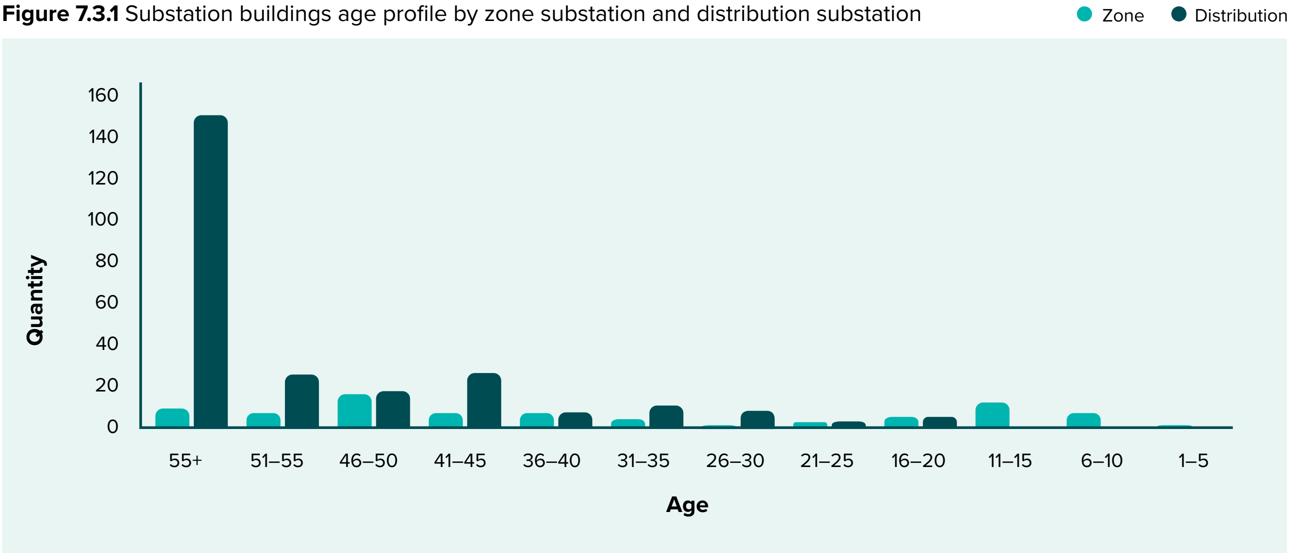
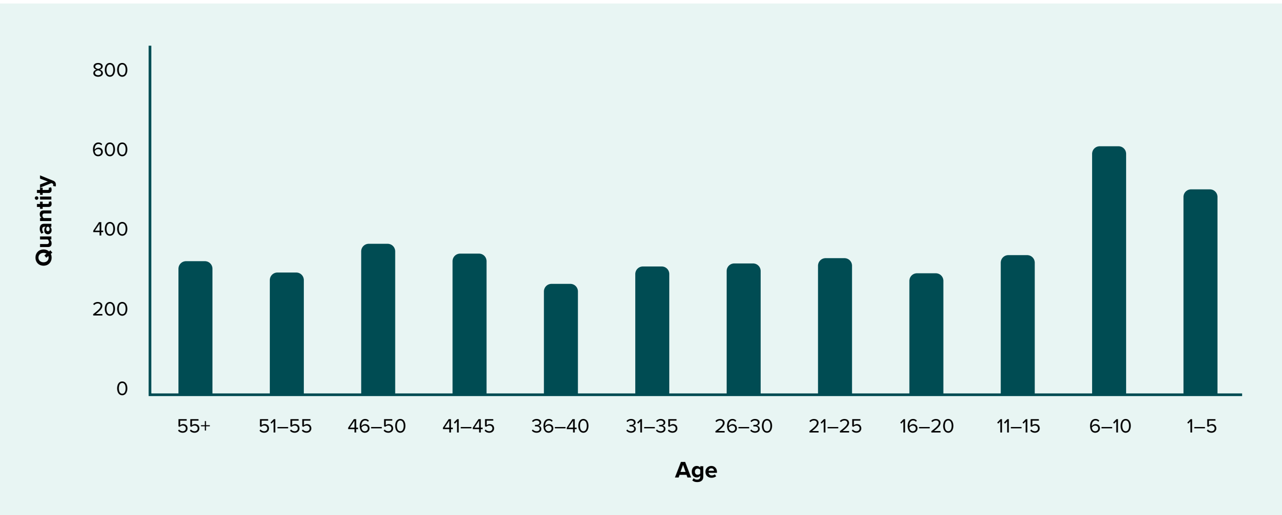


Figure 7.3.2 Kiosk age profile



7.3.3.2 Reliability

The reliability of the equipment is not impacted by the buildings or housings, providing they are kept secure. Orion rigorously controls security and entry to its substations, with regular monitoring of site security.

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 and illegal entry onto our sites poses a risk to the persons health and safety	Our 10-year programme to upgrade security and safety has been completed. This involved access (locks and gates/doors), fencing and earthing. All ground-mounted installations in industrial and commercial locations have already been independently surveyed to gauge their susceptibility to damage. To improve public safety we are currently installing double fencing to the majority of zone substations; boundary fencing and security fencing
	Vegetation in and around our assets poses an operational safety hazard	We conduct planned 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 to our assets can be restricted if contained within buildings susceptible to earthquake damage	We have completed a seismic strengthening programme
	Asbestos in Orion and privately owned sites contained within the building materials poses a risk to the health of our staff and service providers	Asbestos management plan and asbestos registers, training and education. Procedures and Accidental Discovery Processes (ADP) established
	Work on contaminated land poses a health risk to our people and public and can cause more harm to the environment	ADP are established to control health and environmental risks
Deterioration	Water-ingress into buildings can damage our assets	We conduct routine building inspections and maintenance
	Old wooden substation doors require more maintenance and are not as secure as newer aluminium doors	We replace old wooden doors with aluminium doors

7.3.4 Maintenance plan

The substation monitoring and inspection programmes are listed in Table 7.3.4. Our forecast operational expenditure, Table 7.3.5, is in the Commerce Commission categories.

Table 7.3.4 Network property maintenance plan

Maintenance activity	Strategy	Frequency
Zone substation maintenance	Substation Building Condition Assessments are carried to identify the 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 includes recording any transformer loading (MDI) value. 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 a proactive graffiti removal plan where our service providers survey allocated areas of the city and remove graffiti as they find it	The sites which go through the reporting process are attended usually within 48 hours
Kiosks	Inspection rounds identify any maintenance requirements Grounds maintenance ensuring clear and free access to kiosks is undertaken on urban sites Grounds maintenance on rural sites is undertaken We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas	6 months 2 years As required As required
Substation earthing	A risk-based approach has been taken for the inspecting and testing of our site earths. In general, earth systems in our rural area are subject to deterioration because of highly resistive soils, stony sub-layers of earth 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	A number of our substation buildings were constructed with a flat concrete roof with a tar-based membrane covering. These have been prone to leaking when cracks develop in the concrete. Over the past few years we have begun to upgrade these buildings by constructing a new pitched colour steel roof over the top	Roof replacement is scheduled and prioritised as required, based on survey data

Table 7.3.5 Network property operational expenditure (real) – $000											
	FY23	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**Total**
Service interruptions and emergencies	-	-	-	-	-	-	-	-	-	-	**-**
Routine and corrective maintenance and inspections	2,412	2,313	2,313	2,331	2,322	2,322	2,322	2,331	2,322	2,322	**23,310**
Asset replacement and renewal	95	95	95	95	95	95	95	95	95	95	**950**
Total	**2,507**	**2,408**	**2,408**	**2,426**	**2,417**	**2,417**	**2,417**	**2,426**	**2,417**	**2,417**	**24,260**

7.3.5 Replacement plan

The forecast capital expenditure in Table 7.3.6 in Commerce Commission categories covers the following:

- Ongoing replacement of our substation ancillary equipment such as battery banks and battery chargers
- Our replacement programme to address safety and seismic risk of some older pole substation sites by upgrading the substation design to current standards

In addition, we are planning to do the following:

- Upgrade security fencing
- Targeted replacement of steel kiosks located near the coast due to rust

Table 7.3.6 Network property replacement capital expenditure (real) – $000											
	FY23	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**Total**
Zone substations	319	100	100	100	100	100	100	100	100	100	**1,219**
Distribution substations and transformers	487	487	487	487	487	422	468	502	527	520	**4,874**
Other network assets	749	448	446	410	410	477	514	541	560	555	**5,110**
Total	**1,555**	**1,035**	**1,033**	**997**	**997**	**999**	**1,082**	**1,143**	**1,187**	**1,175**	**11,203**

7.3.5.1 Disposal

We assess ownership of interests in a property, in particular easements on unused sites. We will relinquish ownership of these sites as and when required. The procedures for disposal are shown in Table 7.3.7.

Table 7.3.7 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 asset design standards for substations contain information on how to risk assess works in and around potentially contaminated land and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. A network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces

More than 50% of our 66kV poles are less than 20 years old and are well within their life expectancy.

7.4 Overhead lines – subtransmission

7.4.1 Summary

Our subtransmission network spans 506 kilometers and is the backbone of our service to customers. These lines are supported by 396 towers and 5,425 poles. Any failure of our subtransmission network has the potential to severely affect our safety and performance objectives, and disrupt our customer's lives.

The overall condition of Orion's subtransmission lines is good. Our asset management strategy and practices for our tower fleet are currently under review to ensure we achieve the best possible lifecycle outcomes.

We are developing a painting programme for our towers which makes up majority of the maintenance expenditure, together with regular condition inspections. Each year we reconstruct parts of our subtransmission network which are near end of life by replacing poles and end of life components such as insulators, crossarms and conductors.

7.4.2 Asset description

Here we describe our 33kV and 66kV overhead line asset components. For a map and detailed description of our subtransmission network configuration see Section 6.

Our subtransmission overhead asset has three distinct components; towers and poles; tower and pole top hardware; and conductors.

Towers

Our towers are steel lattice type, supported by different foundation types to maintain the stability and functionality of our overhead subtransmission network. Most are a mixture of concrete footings and grillage. Grillage is a framework of crossing beams used for spreading heavy loads over large areas. Used in the foundations of towers, steel grillage was buried directly into the ground for tower foundations in the 50s and 60s, and more recently it is encased in concrete.

Poles

We use three types of poles:

Timber – hardwood and softwood. Hardwood has superior strength over softwood poles due to its dense fibre characteristics. Nominal service life of hardwood poles depends on timber species, preservative treatment and configuration. Timber poles in areas in areas of harsh environment conditions have a reduced service life

Concrete – prestressed concrete poles have superior tensile strength compared to precast concrete. We no longer install precast poles on our network

Steel – we have 16 steel monopoles specifically designed to suit their location and span length

For a detailed table of poles by type see Table 7.4.1.

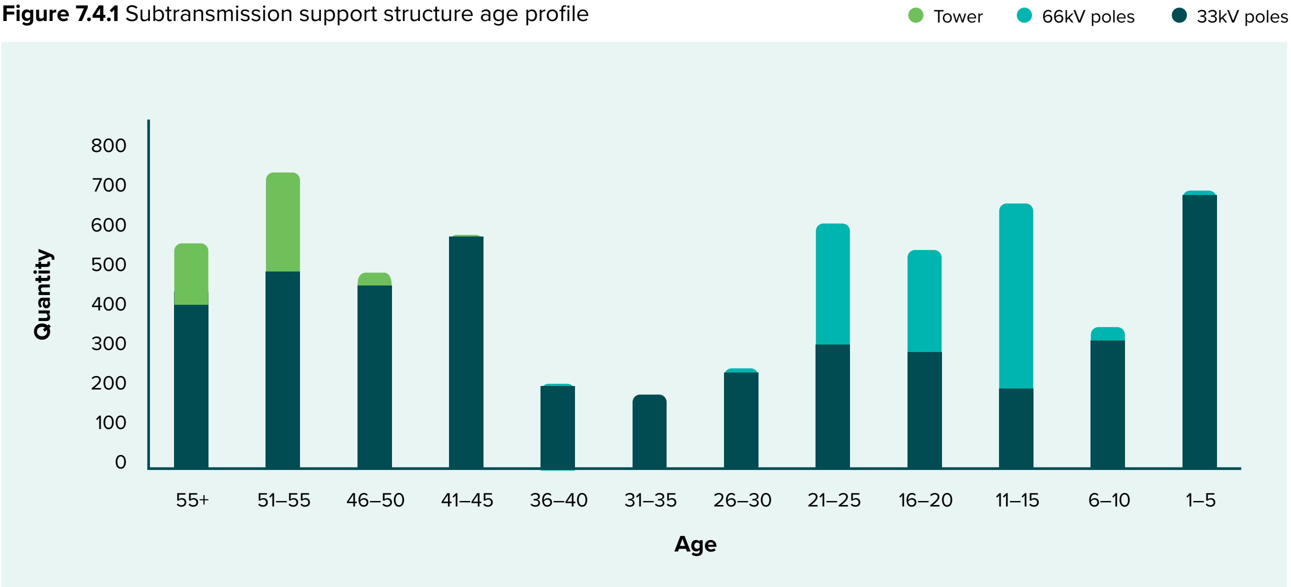
The age profile is shown in Figure 7.4.1. More than 50% of our 66kV poles are less than 20 years old and are well within their life expectancy. The life expectancy for timber poles is 40 to 45 years, 80 years for concrete poles and 60 years for steel poles.

Overall, our subtransmission poles are in good condition.

Table 7.4.1 Subtransmission support structure type

Type	66kV	33kV	
	Quantity	Quantity	Total
Hardwood pole	999	2,294	3,293
Softwood pole	35	434	469
Concrete pole	24	1,623	1,647
Steel pole	14	2	16
Steel tower	396	-	396
Total	**1,468**	**4,353**	**5,821**

Figure 7.4.1 Subtransmission support structure age profile



Tower hardware
Tower hardware is attached directly to the steel lattice structure. It consists of mainly glass disc assemblies in strain and suspension configurations along with some polymer post insulators.

Pole top hardware
Pole top hardware supports the overhead conductors on the pole. It consists of crossarms and braces, insulators, binders and miscellaneous fixings. Crossarms are constructed of hardwood timber or steel. Orion uses hardwood timber crossarms which have a nominal asset life of 40 years.

We have porcelain, glass disc and composite insulators installed on our network as well as line post, pin and strain types.

Conductors
The conductor types used in our subtransmission overhead network are largely aluminum conductor steel reinforced cable (ACSR) and hard drawn copper (HD). Their different attributes are:

ACSR – a stranded conductor used extensively on our HV network. This conductor is chosen for its high strength good conductivity and lower cost when compared to copper. It performs well under snow, wind and ice environments.

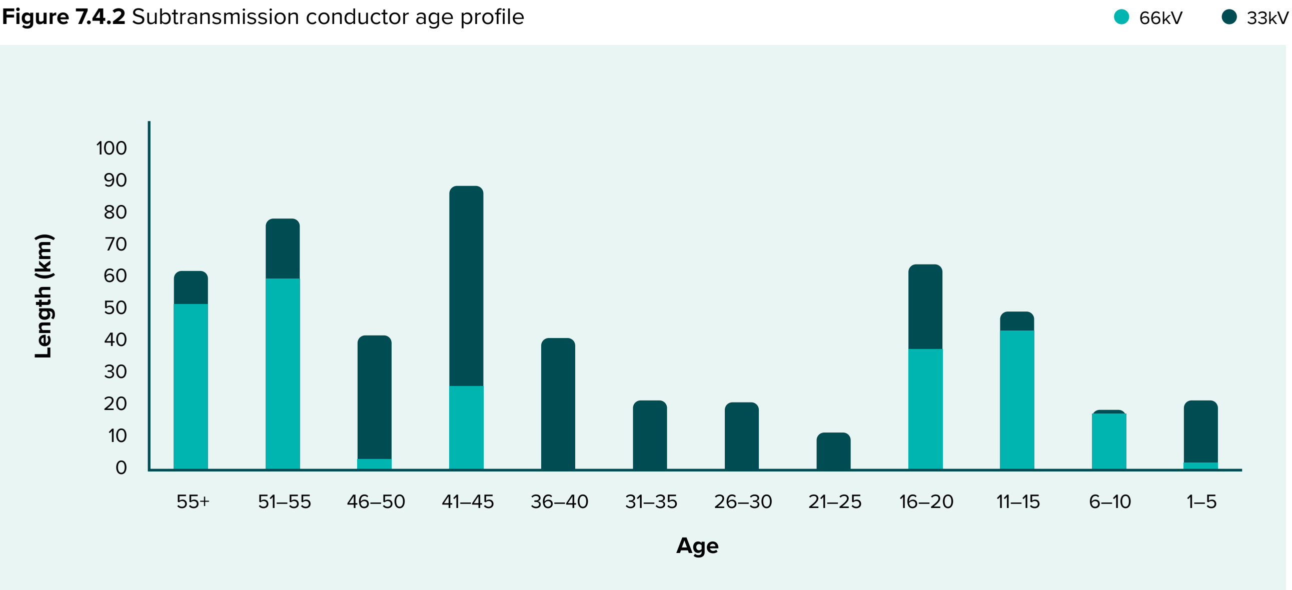
HD – hard drawn stranded copper conductors offer greater flexibility than other conductor types. These conductors are installed on our LV and HV networks, excluding 66kV. Due to its cost and other modern alternatives we now only install it on our LV network when we do replacement works.

Details of conductor type and age profile can be found in Table 7.4.2 and Figure 7.4.2.

Table 7.4.2 Subtransmission conductor type

Type	66kV	33kV	
	Length (km)	Length (km)	Total
ACSR	259	213	472
HD copper	-	34	34
Total	**259**	**247**	**506**

Figure 7.4.2 Subtransmission conductor age profile



7.4.3 Asset health

7.4.3.1 Condition

Towers

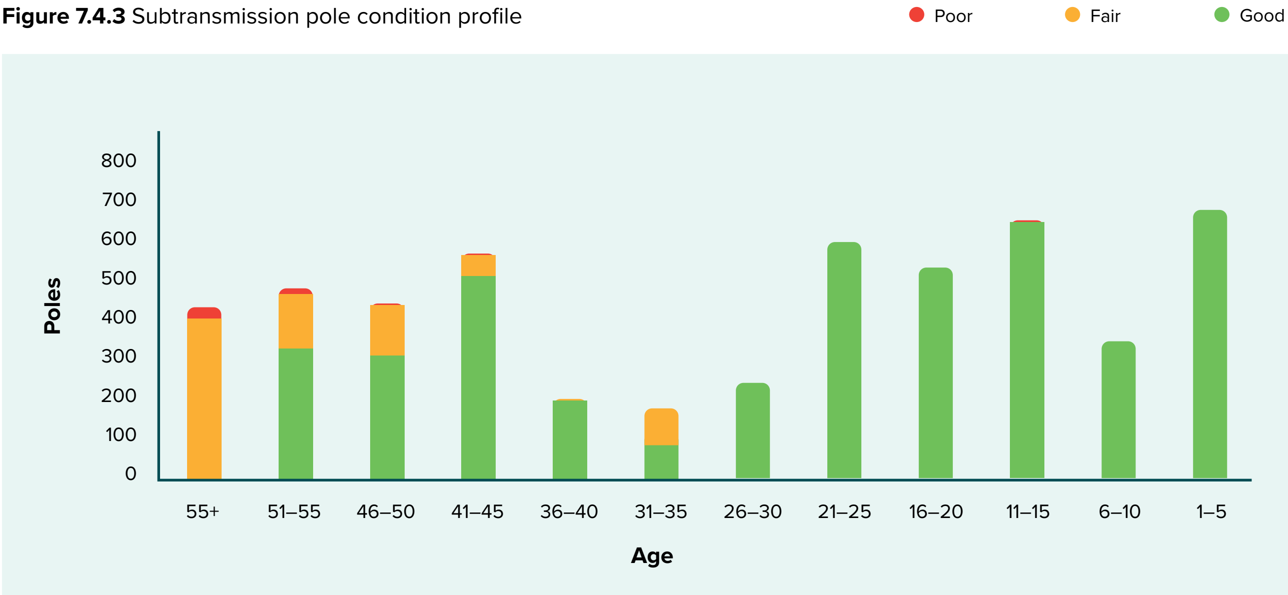
The overall condition of our steel towers is good. The Transpower spur assets - Addington and Islington to Papanui - were purchased with no additional paint protection which we are addressing with our painting programme. We have a foundation refurnishment and concrete encasement programme to address the condition of these towers. The condition of the tower grillage foundations below ground level is good and as a result this work has been deferred and budget moved to FY26.

Poles

As shown in Figure 7.4.3 the overall condition of the subtransmission poles is good. More than 50% of our 66kV poles are less than 20 years old and therefore are in good condition. Most of the 33kV poles are older but are also in good condition, with some mainly timber pole age-related deterioration. These are being prioritised for replacement.

The overall condition of our steel towers is good.

Figure 7.4.3 Subtransmission pole condition profile

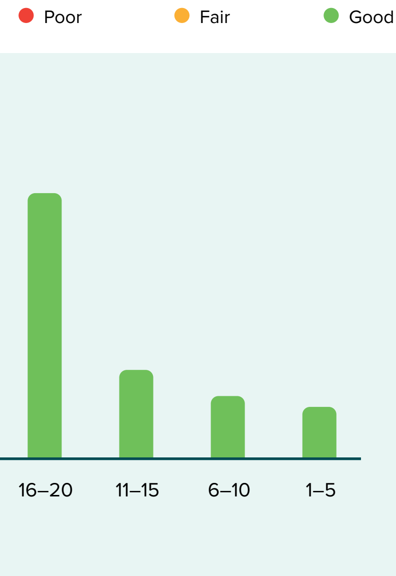


Conductors

The conductors on our overhead subtransmission network are performing well, see Figure 7.4.4. The copper conductors on some 33kV lines are older and showing some signs of wear and is being monitored during routine maintenance. The ACSR conductors on the tower lines are generally in good condition.

We have undertaken detailed testing of some tower line conductors. The Bromley to Heathcote line is in fair condition due to its age, circa 1957, and coastal location. We expect to replace this conductor later in the 10 year plan. We will retest these conductors in the interim to assess the rate of deterioration and better determine end of life.

Figure 7.4.4 Subtransmission conductor condition profile

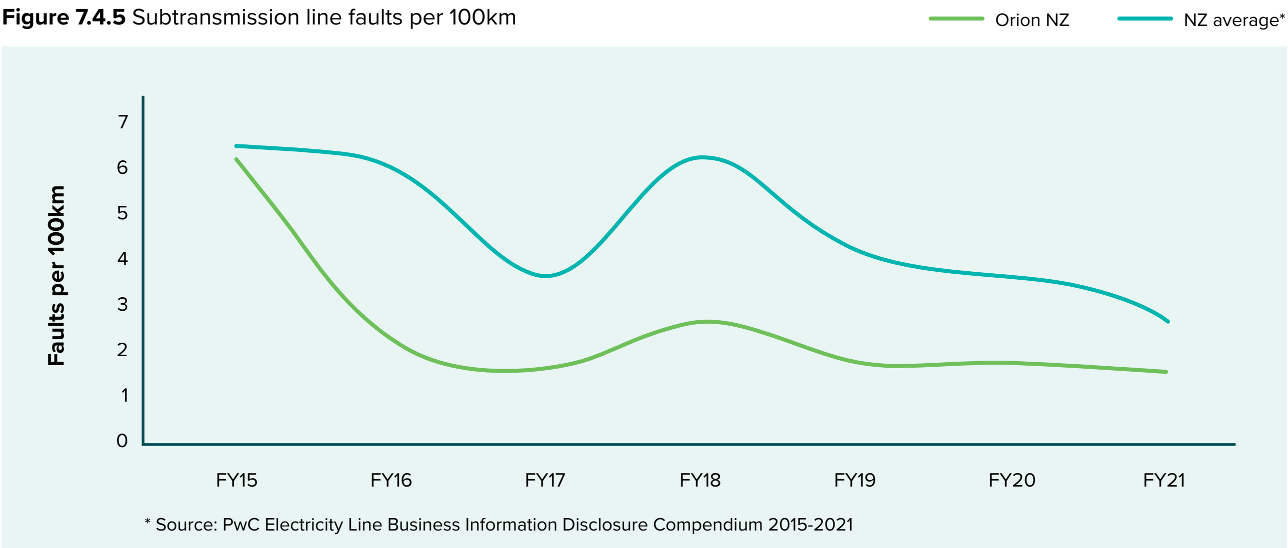


7.4.3.2 Reliability

Our subtransmission lines failure rate has been lower than the industry average for the last seven years. See Figure 7.4.5.

Our subtransmission lines failure rate has been lower than the industry average for the last seven years.

Figure 7.4.5 Subtransmission line faults per 100km



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 **Conductors** – degrade over time, fretting, corrosion, loss of cross-sectional area **Hardware** – binders fatigue and insulators fail over time. Wooden crossarms can fail due to decay/rot. Insulators on wooden crossarms may loosen due to shrinkage or rot	Robust design standards exceed AS/NZS7000-2016 Pole inspection programme and replacement programme Conductor visual inspection Maintenance inspections and re-tightening programme
Third party interference	**Poles** – third party civil works haves the potential to undermine pole foundations **Conductors** – working near power lines can be fatal or lead to serious injury **Conductors** – clearance from the road surface may change over time because of road resurfacing, vehicle contact with poles or conductors sagging too low	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 A High Load consent is required when transporting loads with an overall height of 4.8 meters and higher along the road corridor Conductor crossing height inspected and maintained for compliance (NZECP34)
	Conductor – trees in contact with conductors can cause damage to the conductor and heighten the risk of electrocution to anyone coming into contact with them or environmental impacts	Tree regulations Vegetation control work programme Tree cut notices are sent to tree owners Public information advertising campaign
Environmental conditions	**Timber poles** – ground conditions can contribute to pole structure decay **Conductors** – 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 high wind 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

7.4.4 Maintenance plan

Our maintenance activities as listed in Table 7.4.4, are driven by a combination of time-based inspections, maintenance and reliability centred 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 x-ray inspection Tower lines have sections of conductor removed and tested	As required
Subtransmission thermographic survey	This technology can 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	Our obligation is to keep the network safe. We follow the annual tree management programme to remove vegetation when it is required Our vegetation trimming programme consists of clearing only allows us to cut trees inside specific zones that are stipulated in the regulations – most vegetation faults happen outside these zones and are out of Orion's control. In 2020, we introduced a new programme to address problem trees and vegetation outside of these specified zones. As part of our programme we have also implemented electronic platforms to manage programme data collection, reporting and contractor accountability We also notify tree owners if their trees might become a hazard, and conduct public information advertising campaigns We will continue to be proactive and carry out the HV tree management programme, work with and educate land owners on the importance of vegetation management around the network and identify and remove vegetation that is at risk of impacting on the network both inside and outside the Notice Zone	2 years
Retightening / refurbishment programme	Retightening of hardware components for pole lines only and the replacement of problematic assets if required; e.g. 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 steel condition and we undertake further investigation when issues are highlighted. The ongoing painting programme is designed to protect good steel prior to any issues arising, and the coatings systems are then maintained to optimise this protection	Approx. 30 – 40 years from new, dependent on environmental factors
Tower foundations	Tower foundation maintenance is focused on the concrete encasement programme for the existing grillage foundations, and once this is complete only the above ground interfaces will need ongoing attention	One off
Tower inspection	Visual and lifting inspections provides condition assessment of the tower steel, bolts, attachment points, insulators, hardware and conductors	10 years for visual and lifting inspections 20 years each circuit (10 years each line)

A breakdown of subtransmission overhead opex in the Commerce Commission categories is shown in Table 7.4.5. The annual operational expenditure forecast is expected to maintain our current good performance for this asset class.

Table 7.4.5 Subtransmission overhead operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	155	155	155	155	155	155	155	155	155	155	**1,550**
Routine and corrective maintenance and inspections	1,655	1,525	1,620	1,610	1,930	1,875	1,925	1,910	1,860	1,860	**17,770**
Asset replacement and renewal	0	0	0	250	250	250	250	250	250	250	**1,750**
Total	**1,810**	**1,680**	**1,775**	**2,015**	**2,335**	**2,280**	**2,330**	**2,315**	**2,265**	**2,265**	**21,070**

7.4.5 Replacement plan

Towers

Currently we have not seen any evidence to suggest any of our towers require replacement.

Poles

Our replacement strategy is based on a combination of our risk-based approach to replacement and our new pole inspection programme. We have set an asset class objective to maintain a pole failure rate of less than one in ten thousand poles and reduce our faults per km rate. In setting this objective we considered two scenarios ‘do nothing’ and ‘targeted intervention’.

‘Do nothing’ involves regular maintenance only, but our chosen solution identifies and prioritises poles based on condition and criticality.

We plan to continue replacing our 33kV poles at a steady rate. The replacement rates have been projected with consideration for cost vs benefit and constraints on resource requirements. We continue to monitor our performance and safety to ensure the optimum levels of replacement are delivered. Based on our projected pole replacement plan, the current and future pole health scenarios are shown in Figure 7.4.7.

We have set an asset class objective to maintain a pole failure rate of less than one in ten thousand poles and reduce our faults per km rate.

While our asset management approach is risk based historically it has been difficult to produce a visual representation of this. In 2019 the Electricity Engineers Association (EEA) released an asset criticality guide which gives industry-led guidance on how to determine an asset's criticality and provides descriptions and grades of risk. As mentioned in Section 5.6, we have produced a risk matrix for our pole assets fleet based on the EEA Asset Criticality Guide. Figure 7.4.6 is an example of our current, do nothing and targeted intervention risk profile for our subtransmission poles over the next 10 years. It shows that if we do nothing it poses a significant risk to us in the future where we would struggle to avoid catastrophic failures of poles.

Figure 7.4.6 Subtransmission pole risk matrix

Current

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	0	1	33	0	34
H2	0	3	14	0	17
H3	0	147	610	0	757
H4	0	305	1,165	0	1,470
H5	0	484	2,648	0	3,132
Total	0	940	4,470	0	5,410

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

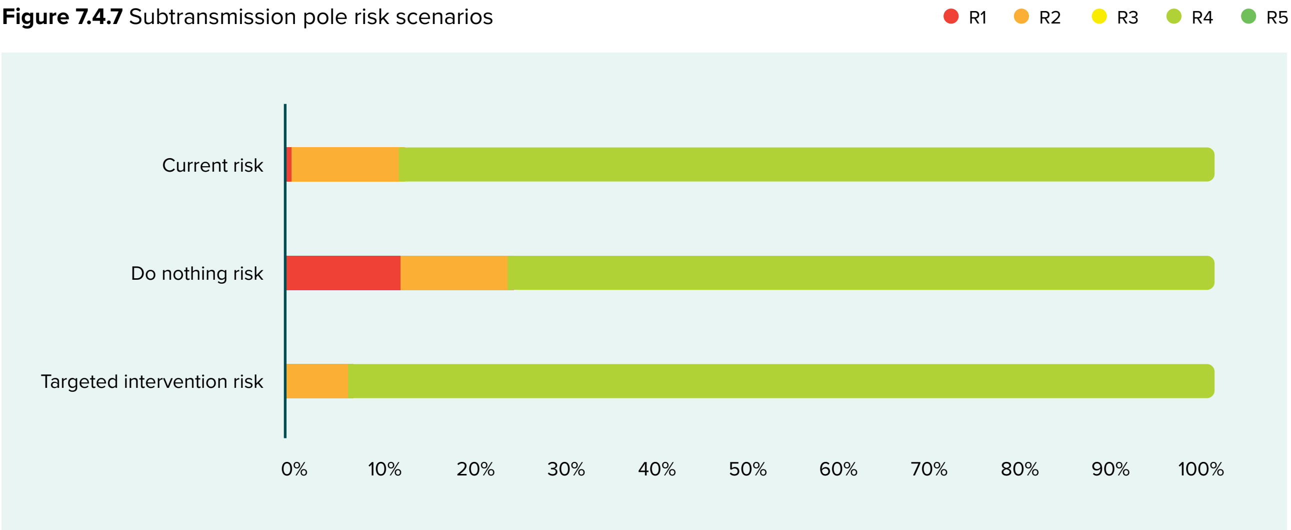
Do nothing at Y10

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	0	6	601	0	669
H2	0	0	9	0	9
H3	0	257	619	0	876
H4	0	309	1,888	0	2,197
H5	0	306	1,353	0	1,659
Total	0	940	4,470	0	5,410

Targeted intervention at Y10

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	0	0	0	0	0
H3	0	145	364	0	509
H4	0	309	1,888	0	2,197
H5	0	486	2,218	0	2,704
Total	0	940	4,470	0	5,410

Figure 7.4.7 Subtransmission pole risk scenarios



Pole top hardware

For economic efficiency crossarms and insulators are replaced or refurbished in conjunction with the pole replacement programme, the line retightening programme and targeted programmes if required.

Conductors

We have tested conductor samples from our Bromley to Heathcote, Islington to Halswell and Heathcote to Barnett Park lines to determine end of life. Our testing confirmed we may need to replace the conductor on our Bromley to Heathcote line. Replacement has been deferred while we assess options and will be included in the FY27 budget.

We also intend to replace portions of these overhead lines with new conductor and have a placeholder budget for FY29.

A breakdown of subtransmission overhead capex in the Commerce Commission categories is shown in Table 7.4.6. The annual capital expenditure forecast is expected to maintain our current good performance for this asset class.

Table 7.4.6 Subtransmission replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtransmission	1,260	990	90	1,080	3,745	1,468	4,782	1,680	1,746	1,729	**18,570**
Total	**1,260**	**990**	**90**	**1,080**	**3,745**	**1,468**	**4,782**	**1,680**	**1,746**	**1,729**	**18,570**

7.4.5.1 Disposal

All poles are disposed of by our service providers in a manner appropriate to the pole type. A lifecycle analysis carried out in 2020 confirmed 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 dispatched to landfill. Metal materials are disposed of through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

7.4.6 Innovation

We have adopted a non-destructive x-ray testing technology which enables us to better determine conductor condition and optimal replacement timing of our subtransmission conductor. We have trialed the use of a resistance drill on our timber poles to help identify internal decay and have an improved pole inspection process. Results have been positive, and the drill is only used sporadically when deemed necessary by Orion engineers. We are now using Unmanned Aerial Vehicles (UAVs) to assist us to maintain and inspect our network. UAVs provide us with cost savings and improved inspections.

Our 11kV distribution overhead system has 3,146km 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 Region B and outer Christchurch city. Their failures have the potential to negatively affect our safety objectives, and disrupt the lives of the community. We are increasing 11kV lines expenditure over the next 10 years, mainly to minimise pole failures, but also to maintain overall reliability and asset condition.

7.5.2 Asset description

Our 11kV distribution overhead system is 3,146km of lines servicing the rural area of central Canterbury, Banks Peninsula and outer areas of Christchurch city. These lines are supported by 47,522 timber and concrete poles, some of which also support subtransmission and 400V conductors.

Our 11kV lines are supplied from zone substations. Supply is also taken directly at 11kV from the GXPs at Coleridge, Castle Hill and Arthur's Pass. We have 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 assets: pole, pole top hardware and conductor.

Poles

The 11kV poles provide support for the 11kV line assets and other classes of network assets, such as pole-mounted transformers, low voltage lines and associated hardware. There are four types of poles used on our network:

- **Timber** – comes in hardwood and softwood. Hardwood has superior strength over softwood poles due to its dense fibre characteristics. The nominal service life of hardwood poles depends on the timber species, preservative treatments and configuration. Timber poles in areas exposed to harsh environmental conditions have a reduced nominal service life
- **Concrete** – pre-stressed concrete poles which have superior tensile strength compared to precast concrete. We no longer install precast poles on our network
- **Steel** – we have four steel monopoles specifically designed to suit their location and span length. We have installed concrete pile foundations to support these poles
- **Steel pile** – we have 44 steel pile structures to support the hardwood poles in or near riverbeds

Today, we predominantly install timber poles. Table 7.5.1 shows the pole types and quantities installed on our network.

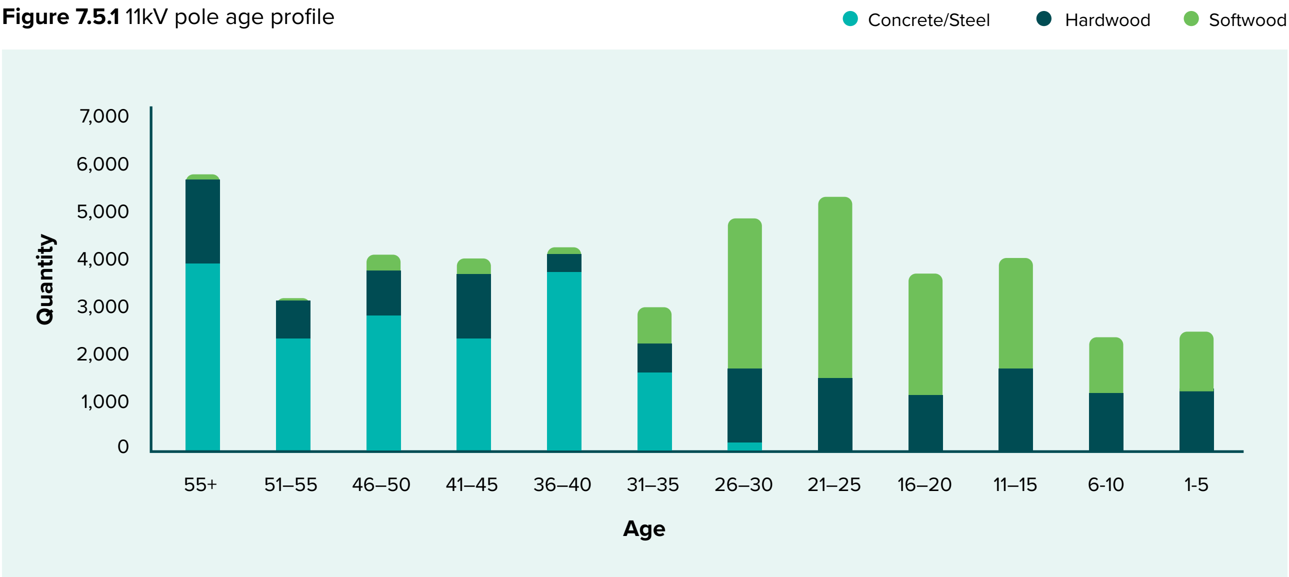
Table 7.5.1 11kV pole quantities by type

Pole type	Quantity
Timber (Hardwood)	14,151
Timber (Softwood)	16,047
Concrete	17,276
Steel pole and piles	48
Total	**47,522**

7.5 Overhead lines – distribution 11kV continued

The Figure 7.5.1 age profile shows a transition in the 1990s from concrete poles to timber poles. This change was made based on a combination of lifecycle economics and engineering considerations. It also shows that the majority of our older poles are concrete and steel.

Figure 7.5.1 11kV pole age profile



Pole top hardware
Pole top hardware are components used to support overhead conductors on the pole. This consists of crossarms and braces, insulators, binders and miscellaneous fixings. Crossarms are constructed of either hardwood timber or steel. We use hardwood timber crossarms which have a nominal asset life of 40 years. We have porcelain, glass and polymer insulators installed on our network. We do not have complete records of the ages of these components.

Conductors
A variety of conductor types are used for the 11kV overhead network. The decision as to which conductor type is used is influenced by economic considerations, the asset location, environmental and performance factors. The number of conductor types we use is listed in Table 7.5.2.

They are:

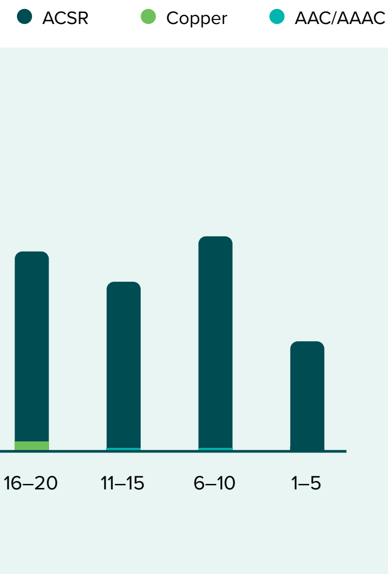
- **HD Copper –** hard drawn stranded copper conductor, which is no longer installed on our 11kV network
- **Aluminium conductor-steel reinforced (ACSR) –** a stranded conductor used extensively on our HV network. This conductor is chosen for its high strength good conductivity and lower cost when compared to copper. It performs well in snow, wind and ice environments
- **Other aluminium –** all 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 also offer improved electrical properties and corrosion resistance

Table 7.5.2 11kV conductor quantities by type

Conductor type	Length (km)
HD Copper	279
Aluminium (ACSR)	2,805
Other Aluminium (AAC & AAAC)	62
Total	**3,146**

The age profile in Figure 7.5.2 shows that our conductor population is predominantly ACSR, with hard drawn copper the second most prevalent conductor type.

Figure 7.5.2 11kV conductor age profile



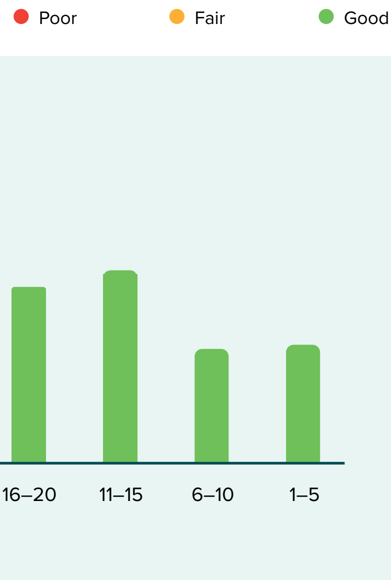
7.5.3 Asset Health

7.5.3.1 Condition

Poles

The condition of our 11kV network has been modelled using CBRM. Figure 7.5.3 shows the current age and condition profile for our overhead 11kV poles. Our poles are predominantly in good condition.

Figure 7.5.3 11kV pole condition profile



Conductor

Across our wide range of conductor types and ages we have identified a number of poorer performing conductor types. A replacement programme has targeted the worst performing (7/16 Cu) conductors. Once that has been completed, we will replace a range of small and end-of-life ACSR conductors.

7.5 Overhead lines – distribution 11kV continued

7.5.3.2 Reliability

Figure 7.5.4 is compiled using information disclosure data. It shows our 11kV lines fault rate per 100km has been higher than the industry average and has also exceeded our target of 18 faults per 100km. The increase in overhead fault rate is due to wildlife which climb onto the power lines, vegetation and lightning strike.

A contributing factor may be warmer weather conditions which caused a mega mast year 2019/2020 creating exceptionally high levels of plant seeds, stimulating higher breeding rates of wildlife such as possums and rats. These conditions are also favourable to faster growth rates for vegetation.

Lightning Strikes
We have seen a significant increase in lightning strikes in recent years particularly in spring and summer with warmer temperatures. These happen predominantly in the rural and Banks Peninsula areas and are sporadic in nature.

Wildlife
Over the last four years we seen an increase of possums coming into contact with our overhead lines. Orion has been installing possum guards on the concrete poles that have 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 land owners to manage their trees. We have also initiated a project to target areas with fast growing vegetation issues.

While the number of faults is increasing, our reliability with regards to SAIDI and SAIFI is improving. This is likely to as a result of our installation of remote line switches on our network that enable us to switch and restore the network faster in response to faults.

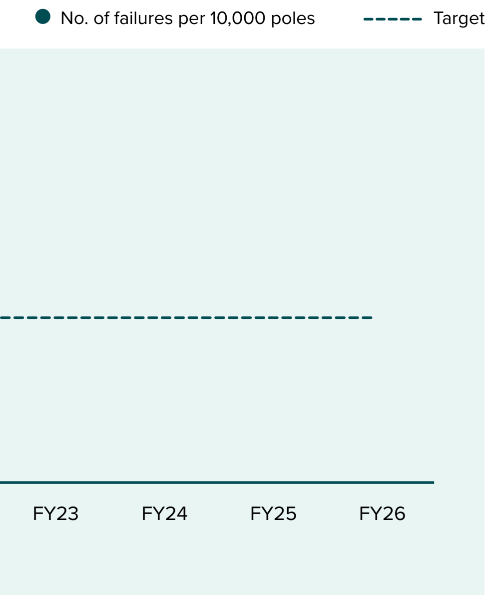
Figure 7.5.4 11kV line faults per 100km

* Source: PwC Electricity Line Business Information Disclosure Compendium 2015-2021

Pole failure rate

To support public safety and network reliability we have established a pole failure rate[1] target of less than one failure per 10,000 of all pole voltage classes combined. In 2016 we established a more robust definition of 'pole failure' along with a renewed approach to identifying and reporting suspect poles. Since taking effect, five years of comparable data has been reviewed under this benchmark. Figure 7.5.5 shows we met our asset class objective for the last five years.

Figure 7.5.5 Pole failure rate (all voltage classes)



[1] "Pole Failure" is 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. We have monitored our poles according to this definition since 2016.

7.5 Overhead lines – distribution 11kV continued

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 **Conductor** – degrades over time, fretting, corrosion, loss of cross–sectional area **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

Regular inspections are carried out to ensure the safe and reliable operation of our assets. This supports Orion's asset class objectives to maintain our overhead network performance in balance with risk and cost to meet customer expectations.

Our maintenance activities, as listed in Table 7.5.4, are driven by a combination of time based inspections, and reliability centred maintenance.

Table 7.5.4 11kV overhead maintenance plan

Maintenance activity	Strategy	Frequency
Pole inspection	Detailed inspection of poles and lines including excavation for some types	Five 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	Two years
Vegetation management	We have a proactive programme in place to trim trees within the corridor stated in the tree regulations. We also consult with land owners with trees that pose a risk to our assets, but are outside the trim corridor. Refer to Table 7.4.4 for more information	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)

An annual forecast of 11kV overhead operational expenditure in the Commerce Commission categories is shown in Table 7.5.5.

Table 7.5.5 11kV overhead operational expenditure (real) $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	**12,050**
Vegetation management	4,000	4,100	4,200	7,400	7,400	7,400	7,400	7,400	7,400	7,400	**64,100**
Routine and corrective maintenance and inspection	994	2,237	2,328	7,401	6,244	6,374	7,617	7,673	7,569	6,069	**54,506**
Asset replacement and renewal	1,522	1,325	1,692	1,899	2,464	2,396	2,242	2,470	3,191	3,191	**22,392**
Total	**7,721**	**8,867**	**9,425**	**17,905**	**17,313**	**17,375**	**18,464**	**18,748**	**19,365**	**17,865**	**153,048**

7.5.5 Replacement plan

Poles

As a pole's age increases, so too does its probability of failure, and defects and condition driven failures are likely to increase. To meet our asset class objective to maintain 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:

- **Targeted intervention –** the chosen solution which identifies and prioritises poles based on condition and criticality
- **Do nothing –** regular maintenance only, but does not prevent material deterioration in condition
- **Underground conversion –** an option that is normally uneconomical

The optimised replacement approach options are shown in Figure 7.5.6 and Figure 7.5.7.

As mentioned in Section 5.6, 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 it poses a significant risk to us in the future where we would struggle to avoid catastrophic failures of poles.

Figure 7.5.6 11kV pole risk matrix

Current

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	11	85	1	0	98
H2	71	536	15	0	622
H3	537	7,533	539	0	8,609
H4	319	16,428	864	0	17,611
H5	643	18,643	1,281	0	20,567
Total	1,581	43,226	2,700	0	47,507*

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 at Y10

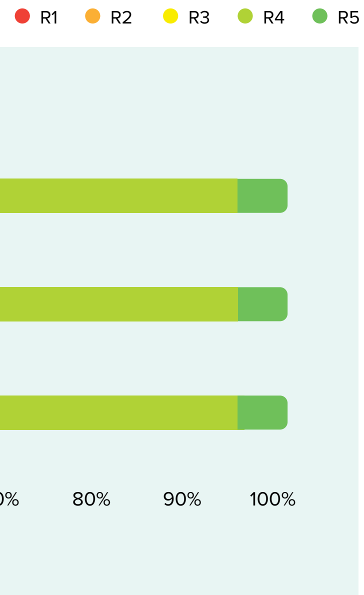
Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	601	5,756	490	0	6,847
H2	14	578	19	0	611
H3	212	12,216	581	0	13,009
H4	491	17,553	1,146	0	7,855
H5	283	7,123	469	0	11,452
Total	1,581	43,226	2,700	0	47,507*

Targeted intervention at Y10

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	23	0	0	0	23
H2	13	510	19	0	542
H3	212	12,211	579	0	13,002
H4	491	17,553	1,141	0	19,185
H5	842	12,952	961	0	14,755
Total	1,581	43,226	2,700	0	47,507*

* Numbers may vary slightly from Table 7.5.1 depending on the timing of data extracts.

Figure 7.5.7 11kV pole risk scenarios



We believe our targeted replacement plan is appropriate as it achieves our asset class objective to maintain a safe, reliable, resilient system. While the targeted intervention risk in Figure 7.5.7 shows some poles as orange (R2) or "high" risk the overall risk profile remains largely the same.

This replacement programme, in conjunction with subtransmission and LV pole replacement supports our asset class objective to maintain less than one in 10,000 failure.

As a result, we are planning a steady increase in the replacement of our mainly timber poles, as shown in Figure 7.5.8.

Figure 7.5.8 11kV pole replacement plan

Pole top hardware
For economic efficiency, crossarms and insulators are replaced or refurbished in conjunction with the pole replacement programme, the line retightening programme and targeted programmes if required. Recently we have been focusing on reliability improvement for rural townships by targeting feeders through a combination of insulator and crossarm replacements and installation of automated line switches.

Conductor
We aim for asset standardisation where possible, so unless demand or capacity reasons dictate otherwise, the standard like-for-like when replacing conductors will be Dog or Flounder ACSR.

Overhead to underground conversion

An option to consider for replacing end of life 11kV overhead lines is the possibility of 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.

A breakdown of 11kV overhead capex in the Commerce Commission categories is shown in Table 7.5.6.

The capex expenditure forecast is expected to contribute to improving our asset class reliability performance while maintaining our pole failure rate to less than one failure per 10,000 poles.

As an outcome of reviewing our pole replacement processes, we identified that replacing all the poles we needed to in a particular area, irrespective of the voltage of the lines, was more efficient than our previous approach of focusing on one asset class at a time.

As a result, the replacement capex for LV poles is combined with 11kV poles and the total capex is shown in Table 7.5.6.

The capex expenditure forecast is expected to contribute to improving our asset class reliability performance while maintaining our pole failure rate to less than one failure per 10,000 poles.

The capital expenditure for this asset class also includes the installation cost for replacing end of life Air Break Isolators (ABI). The material cost is captured in section 7.10 Switchgear. For more information see 7.10.5.

Table 7.5.6 11kV overhead replacement capital expenditure (real) $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Distribution & LV Lines	5,806	7,846	8,356	9,886	12,396	15,944	15,946	16,340	17,090	16,900	**126,510**
Distribution switchgear	525	525	525	525	525	300	300	300	300	300	**4,125**
Other reliability, safety and environment	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	**27,160**
Total	**9,047**	**11,087**	**11,597**	**13,127**	**15,637**	**18,960**	**18,962**	**19,356**	**20,106**	**19,916**	**157,795**

7.5.5.1 Disposal

See section 7.4.5.1.

7.5.6 Innovation

We worked with Christchurch City Council, Selwyn District Council and ECan to improve our operational efficiency and reduce cost by gaining global consents for the repetitive activity of undergrounding cables and installing poles across our network. This innovation in improving our efficiency delivers on our asset management strategy focus on ongoing operational optimisation.

Our customers also benefit from minimising our compliance costs while we continue to meet resource consenting requirements.

We are trialling Fusesavers on our 11kV overhead network. These act as a single-phase circuit breaker and recloser. The benefit of the reclose function is expected to be greatly increased network reliability and fewer power outages for our customers.

We have recently implemented a project to automatically enable/disable our auto-reclosers by network segment in response to localised weather data during high fire risk seasons. Early results show we are decreasing the fire risk and reducing the duration of power outages for our rural customers.

Our low voltage 400V distribution overhead network is 2,354km 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 low voltage 400V distribution overhead network is 2,354km of lines mainly within Region A, delivering power from the street to customer's premises. The lines are supported by timber, concrete and steel poles. To counteract our aging pole population and maintain our performance we are increasing the pole replacement rate and expenditure over the AMP period. We are also improving the quality of our fault data so that we can proactively target areas with vegetation issues. Expenditure on vegetation removal has also increased to target areas of Orion's network that have been significantly impacted by trees on our lines.

7.6.2 Asset description

The 400V overhead asset comprises three distinct components; poles, pole top hardware and conductors.

Poles

There are three types of poles on our LV network:

- **Timber – hardwood and softwood** – hardwood has superior strength over softwood poles due to its dense fibre characteristics. The nominal service life of hardwood poles depends on the timber species, preservative treatments and configuration. Timber poles in areas exposed to harsh environmental conditions have a reduced nominal service life.
- **Concrete – pre-stressed concrete** – have superior tensile strength compared to precast concrete. We no longer install precast poles on our network.
- **Steel poles** – we have three steel monopoles specifically designed to suit their location and span length.

Many of our older timber poles have estimated ages as no install date or manufacture date was recorded or available circa pre-2000. The new pole inspection process introduced in FY22 will address this within a five year period. Table 7.6.1 shows the pole type and quantities on our network.

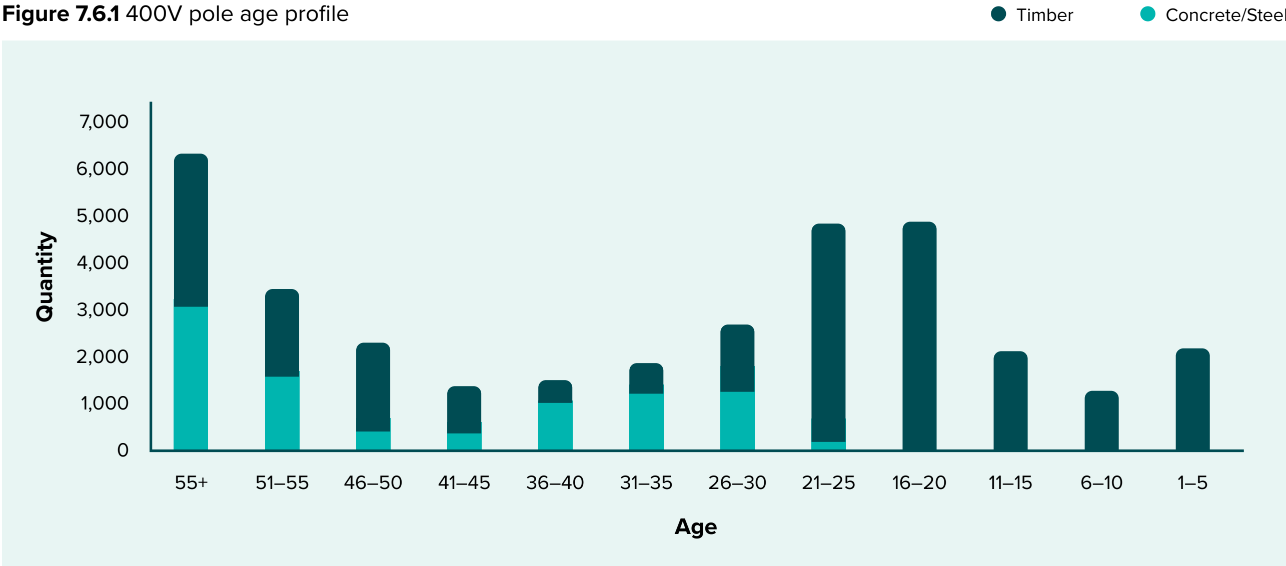
Table 7.6.1 400V pole quantities by type

Pole type	Quantity
Timber (hardwood)	10,783
Timber (softwood)	14,997
Concrete	9,101
Steel	3
Total	**34,884**

The profile in Figure 7.6.1 shows that our older poles are a mix of timber and concrete types. The age profile shows a transition in the 1990s from concrete pole types to timber pole types. This change was made based on a combination of lifecycle economics and engineering considerations.

The age profile also shows a large population of poles aged 16-20 years, which replaced existing poles when a telecommunications network was installed on our poles.

Figure 7.6.1 400V pole age profile



Pole top hardware

Pole top hardware are components used to support the overhead conductor on the pole. This consists of crossarms and braces, insulators, binders and miscellaneous fixings. We use hardwood timber crossarms which have a nominal asset life of 40 years. We have porcelain insulators installed on our network. We collect pole top hardware data on condition and record the age and type for new insulators.

Conductor

We use a variety of mainly covered conductor types for the LV overhead network. The conductor type chosen is influenced by economic considerations, asset location, environmental and performance factors. The different conductor categories are listed in Table 7.6.2.

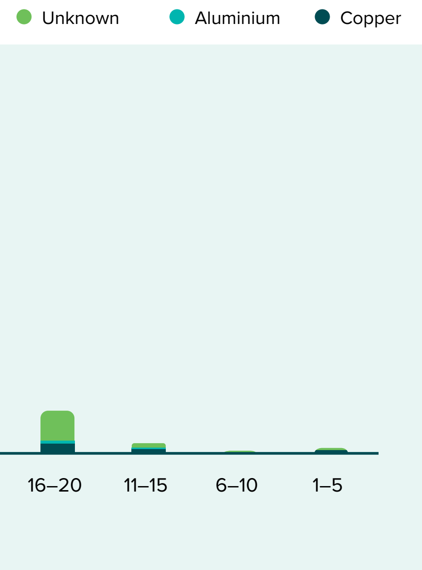
Table 7.6.2 400V conductor quantities by type

Conductor type	Length (km)
Copper (Cu)	792
Aluminium (Al)	148
Unknown	513
Streetlighting (Cu)	901
Total	**2,354***

* Total figure excludes adjustment for road crossings and back section lines.

The age profile in Figure 7.6.2 shows that 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 proportion are recorded as aluminium.

Figure 7.6.2 400V conductor age profile



7.6.3 Asset health

7.6.3.1 Condition

Poles

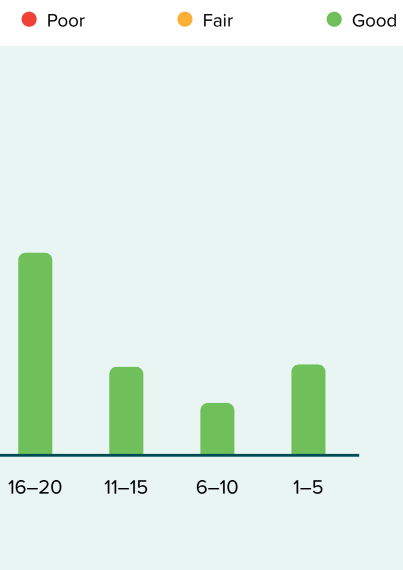
The condition of the low voltage poles has been modelled using the process of CBRM. Figure 7.6.3 shows the condition profile for our overhead LV poles. It can be seen that the pole population is predominantly in good or fair condition, with a smaller amount in poor condition.

Conductors

The condition of the conductors is generally good. However, recent modelling of our LV networks has indicated that some spans are operating above rated capacity. Consequently, we have allocated additional budget for upgrading network in these areas to relieve constraints. See Section 6.6.2.2 for details.

Low voltage conductors are predominantly PVC covered with typically shorter spans and tensions of about 5% of Conductor Breaking Load

Figure 7.6.3 400V pole condition profile



7.6.3.2 Reliability

We are not required to record SAIDI or SAIFI for our LV network. However, to ensure prudent asset management we collect performance data on our LV system. The level of defective equipment has been trending downwards over the last four years. Faults related to adverse weather have also been trending down over the same period and this is due to having fewer major weather events in recent years. We have also improved our data analysis to separate weather and vegetation events down to their root causes.

Historically some events categorised as weather may have been vegetation related. We intend to continually improve the distinction between weather and vegetation related faults so that identified areas with vegetation issues can be addressed. Third party related incidents are slowly trending upwards. The majority of these are due to contractor vehicles and excavators coming into contact with overhead lines.

7.6.3.3 Issues and controls

The controls for reducing the likelihood of failure for 400V overhead asset is the same as 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 reliability centred maintenance.

An annual forecast of 400V overhead operational expenditure in the Commerce Commission categories is shown in Table 7.6.3.

Faults related to adverse weather have also been trending down over the same period and this is due to having fewer major weather events in recent years.

Table 7.6.3 400V overhead operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	**10,000**
Vegetation management	900	900	900	1,800	1,800	1,800	1,800	1,800	1,800	1,800	**15,300**
Routine and corrective maintenance and inspection	3,450	2,250	2,250	2,250	3,350	3,350	2,150	2,150	2,150	3,350	**26,700**
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	**-**
Total	**5,350**	**4,150**	**4,150**	**5,050**	**6,150**	**6,150**	**4,950**	**4,950**	**4,950**	**6,150**	**52,000**

7.6.5 Replacement plan

Poles

In recent times our replacement rate for LV poles has been moderately low. This was in part due to our large investment in the replacement of poles in 2000 and 2001 which brought the condition of our poles up to a very good level. The buffer that this created has now reduced. We plan to increase our replacement rate to maintain the health and failure rate of our LV poles.

As mentioned in Section 5.6, 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 it poses a significant risk to us in the future where we would struggle to avoid catastrophic failures of poles.

Figure 7.6.4 400V pole risk matrix

Current

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	4	135	1	0	120
H2	54	1,893	26	0	1,973
H3	139	8,848	117	0	9,104
H4	21	5,228	56	0	5,305
H5	135	17,934	346	0	18,415
Total	353	34,018	546	0	34,917*

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 at Y10

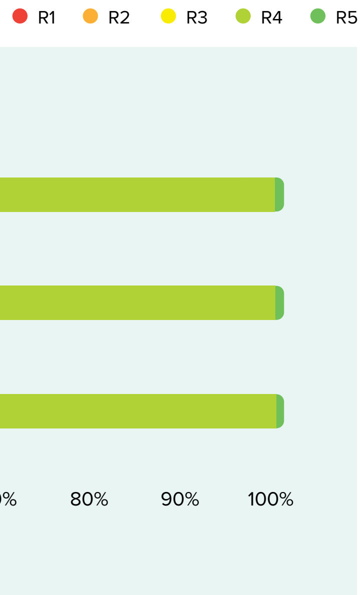
Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	68	2,747	30	0	2,845
H2	114	6,219	91	0	6,424
H3	16	3,255	32	0	3,303
H4	85	13,603	288	0	13,976
H5	70	8,194	105	0	8,369
Total	353	34,018	546	0	34,917*

Targeted intervention at Y10

Asset health index	Asset criticality index: C4	C3	C2	C1	Total
H1	0	0	0	0	0
H2	52	1,756	0	0	1,808
H3	135	8,640	114	0	8,889
H4	21	5,228	56	0	5,305
H5	145	18,394	376	0	18,915
Total	351	34,101	546	0	34,917*

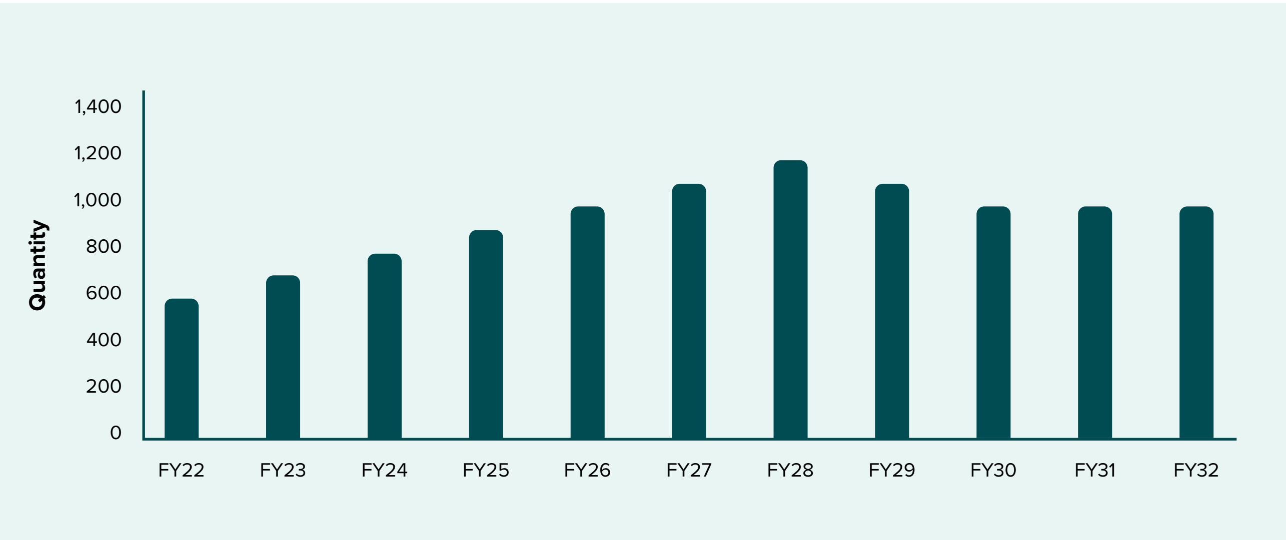
* Numbers may vary slightly from Table 7.6.1 depending on the timing of data extracts.

Figure 7.6.5 400V pole risk scenarios



As a result, we are planning a steady increase in replacement of our mainly timber poles as shown in Figure 7.6.6. This steady increase is necessary to allow time for our service providers to resource appropriately for the work programme.

Figure 7.6.6 400V pole replacement plan



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.

Conductor

We do not have a proactive scheduled replacement plan for LV conductor. Any isolated sections requiring repairs or replacement are repaired or replaced under emergency maintenance or non-scheduled maintenance.

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.

Table 7.6.4 shows the replacement expenditure in the Commerce Commission categories.

As mentioned in Section 7.5, the pole replacement budget for this asset class has been included in the 11kV overhead capex.

Table 7.6.4 400V overhead replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Distribution & LV Lines	390	290	290	290	245	339	390	327	351	345	**3,257**
Other network assets	120	120	120	120	120	120	120	120	120	120	**1,200**
Other reliability, safety and environment	240	160	160	160	160	160	160	160	160	160	**1,680**
Total	**750**	**570**	**570**	**570**	**525**	**619**	**670**	**607**	**631**	**625**	**6,137**

7.6.5.1 Disposal

A lifecycle analysis carried out in 2020 confirmed 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 dispatched to landfill or through members of the Scrap Metal Recycling Association of New Zealand (SMRANZ).

Our subtransmission underground cable network delivers electricity from Transpower's GXPs to substations across the region.

7.7 Underground cables – subtransmission

7.7.1 Summary

Our subtransmission underground cable network is a combination of 66kV and 33kV cables. Their main purpose is to deliver electricity from Transpower's GXPs to zone substations across the region. The majority of our 66kV and 33kV cables are in good condition. We have undertaken a risk assessment of our 66kV oil filled cables and 33kV XLPE cable joints. Our conclusion was that we should continue with our plans to replace our 66kV oil filled cables due to the Alpine Fault risk. For our 33kV cables our risk assessment recommended replacement of the joints which is largely complete.

7.7.2 Asset description

Table 7.7.1 shows that 66kV underground cable consists of older oil-filled cables and more recent XLPE cables. 40km of three core oil filled cables were installed between 1967 and 1981. XLPE cable has been installed since 2001 and it is still our current 66kV cable standard.

We have 37km of 33kV underground cable. It is mostly situated in the western part of Christchurch city, with sections of cable in Rolleston, Lincoln, Prebbleton and Springston. In recent years we have replaced an increasing amount of 33kV overhead line with underground cables as land has been developed and road controlling authorities have requested removal for road upgrades.

Cables are laid in the city to conform to the requirements of the Christchurch city plan. Cables are also installed as a result of customer driven work from developers requiring the undergrounding of our overhead subtransmission lines. Table 7.7.1 shows the age cable type quantities for our 33kV and 66kV network.

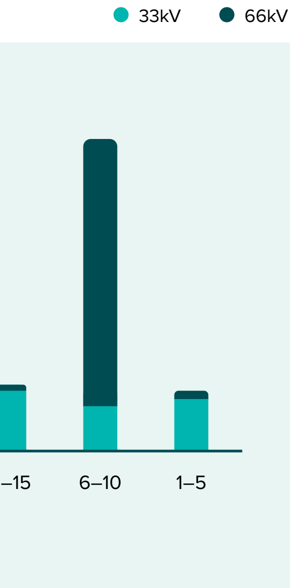
Table 7.7.1 Subtransmission cable length by type

Cable type	Length (km)		
	33kV	66kV	**Total**
PILCA	1.5	–	**1.5**
XLPE	36.5	50	**86.5**
3 core oil	–	40	**40**
Sub-total	38	91	
Total			**129**

7.7 Underground cables – subtransmission continued

Figure 7.7.1 shows the age profile for our 33kV and 66kV network. It can be seen that the majority of our assets are relatively new. The older 66kV cables are 3-core oil filled cables. Our newest 66kV XLPE cable was installed as part of our post-earthquake resiliency work.

Figure 7.7.1 Subtransmission cable network age profile



7.7.3 Asset health

7.7.3.1 Condition

We operate our 66kV cables conservatively which means they have not been subject to electrical aging mechanisms. We monitor the cables to ensure the integrity of their mechanical protection is maintained. We have replaced all the joints that indicated excessive movement of conductors. Some of our oil filled cables have returned poor sheath test results indicating some outer sheath damage. Our 66kV oil filled cable replacement programme will take this into consideration. We continue to inspect the joints as part of an ongoing maintenance plan.

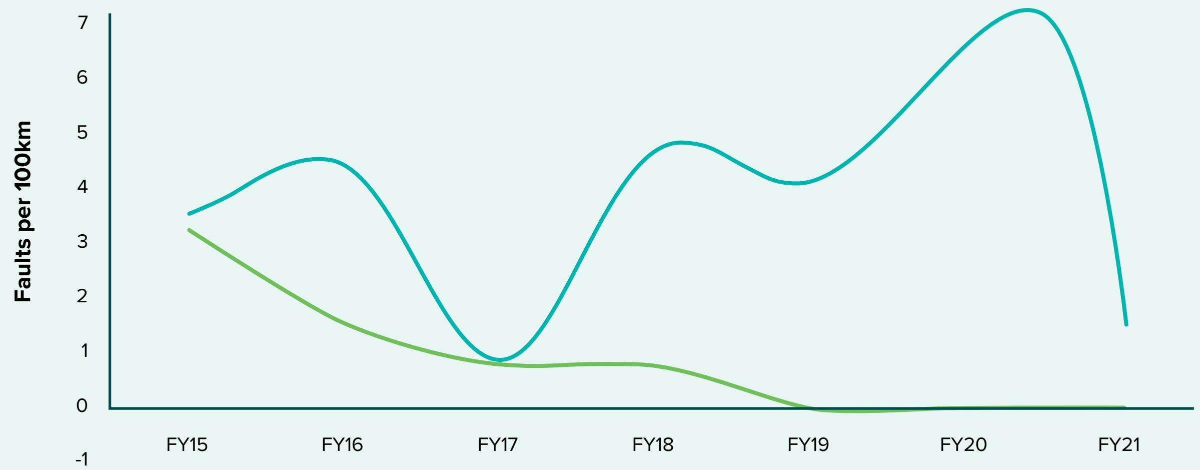
Our 33kV cables are relatively new and are in good condition. During the previous AMP period we identified 33kV joints were in poor condition and deemed them as high risk, and as a result we undertook a joint replacement programme.

7.7.3.2 Reliability

Our 66kV cables were reliable prior to the earthquakes and in recent years. The performance of the cables is based on benchmarks such as SAIDI, SAIFI and defect incident records. An example of a minor defect would be termination issues such as oil leaks which are repaired under emergency maintenance.

Between FY15-FY18 we experience eight 33kV joint failures. Most of these failures were attributed to poor jointing technique or methods. Over the last two years we have had no 33kV joint failures. This is because the risks that were identified with the vulnerable 33kV joints have been repaired.

Figure 7.7.2 Subtransmission underground cable faults per 100km



* Source: PwC Electricity Line Business Information Disclosure Compendium 2015-2021

7.7.3.3 Issues and controls

Subtransmission cable failures are rare, but when they do occur, they can significantly impact our customers through loss of supply. Table 7.7.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.7.2 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	Ultrasonic and partial discharge monitoring of terminations in zone substations
Quality of installation	Poor quality of workmanship while installing cable joints can lead to premature failure impacting reliability further down the track Poorly compacted fill material or naturally soft ground – for example organic clays and peat	Cable jointers are qualified, competent and trained to install specific products. We require them to be certified by the supplier Replacement programme for affected 33kV joints. Minimise high current loads to prevent thermal runaway of suspect joints Inspection of service providers during the laying of cables
Third party interference	Third parties dig up and damage our cables during road reconstruction	33kV and 66kV cables require standover process and consent application for any work Extensive safety advertising in the media. Free training on working safely around cables, including map reading and a DVD Orange coloured sheath 33kV cable is installed to allow easier identification Proactive promotion to service providers of cable maps and locating services

7.7.4 Maintenance plan

Our scheduled maintenance plan for subtransmission cables is summarised in Table 7.7.3 and the operational expenditure in the Commerce Commission categories is shown in Table 7.7.4. This includes a five year programme to inspect and refurbish 66kV joints on the Papanui to McFaddens circuit.

Table 7.7.3 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

Table 7.7.4 Subtransmission underground operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	110	110	110	110	110	110	110	110	110	110	**1,100**
Routine and corrective maintenance and inspections	38	38	38	38	38	38	38	38	38	38	**380**
Asset replacement and renewal	200	200	200	200	200	-	-	-	-	-	**1,000**
Total	**348**	**348**	**348**	**348**	**348**	**148**	**148**	**148**	**148**	**148**	**2,480**

7.7.5 Replacement plan

Our 66kV oil filled cables and joints have a medium to high risk of multiple faults occurring when the Alpine Fault ruptures. Recent research from Te Herenga Waka–Victoria University of Wellington estimates that there is a 75% chance of a major Alpine Fault earthquake in the next 50 years.

To minimise the risk of failure and to continue investing in the network resilience and provide security and confidence for our community, the replacement of our 40km of oil filled 66kV cables will be integrated into a wider 66kV architecture project.

We have allowed expenditure to carry out concept design for the 66kV cable route over the planning period.

7.7.5.1 Disposal

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. We have a network specification that details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

Table 7.7.5 Subtransmission underground capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtransmission	50	50	50	50	50	50	50	50	50	50	**500**
Total	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**500**

90% of our 2,736km network of 11kV underground cables are in the urban area of Christchurch also known as Region A.

7.8 Underground cables – distribution 11kV

7.8.1 Summary

90% of our network of 11kV underground cables are in the urban area of Christchurch also known as Region A. The overall condition of these cables is good. We proactively monitor, test and maintain our 11kV cables. Based on our current assessment, while failures do occur, from a cost-benefit point of view these are not at a significant level to warrant a scheduled 11kV cable replacement programme.

7.8.2 Asset description

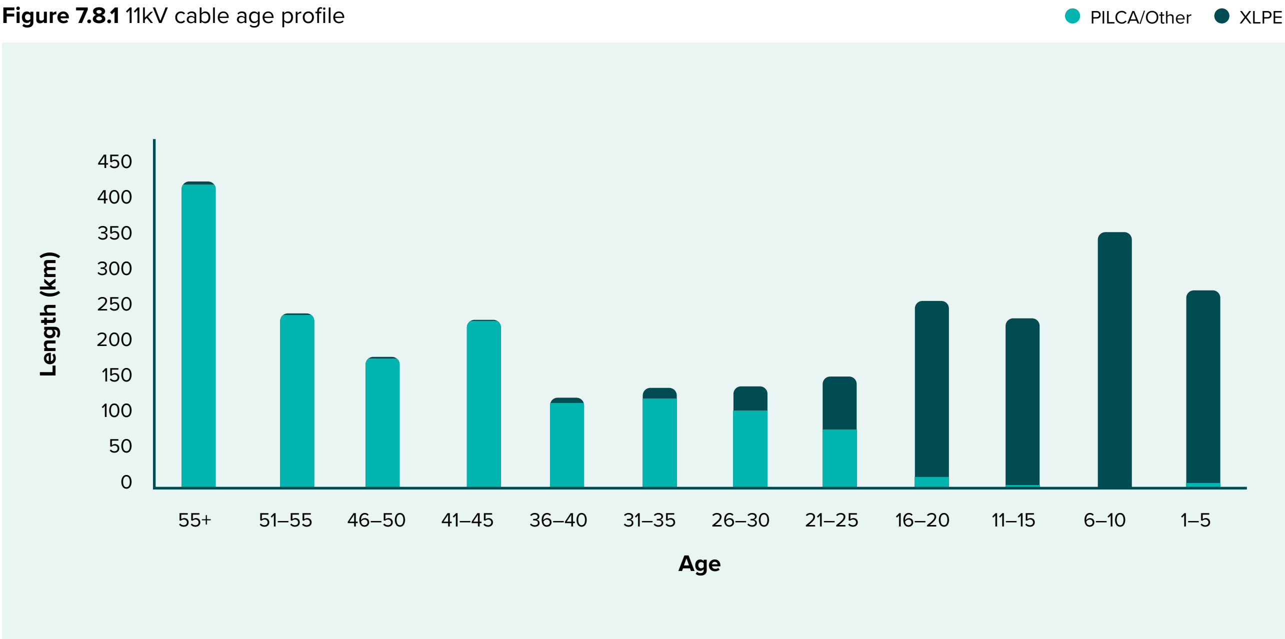
There are two main types of 11kV underground cable in our network:

- **PILCA** – paper insulated lead armour cables
- **XLPE** – cross linked polyethylene insulated power cables

Table 7.8.1 11kV cable length by type

Cable type	Length (km)
PILCA	1,529
XLPE	1,234
Others	2
Total	**2,765**

Figure 7.8.1 11kV cable age profile



7.8.3 Asset health

7.8.3.1 Condition

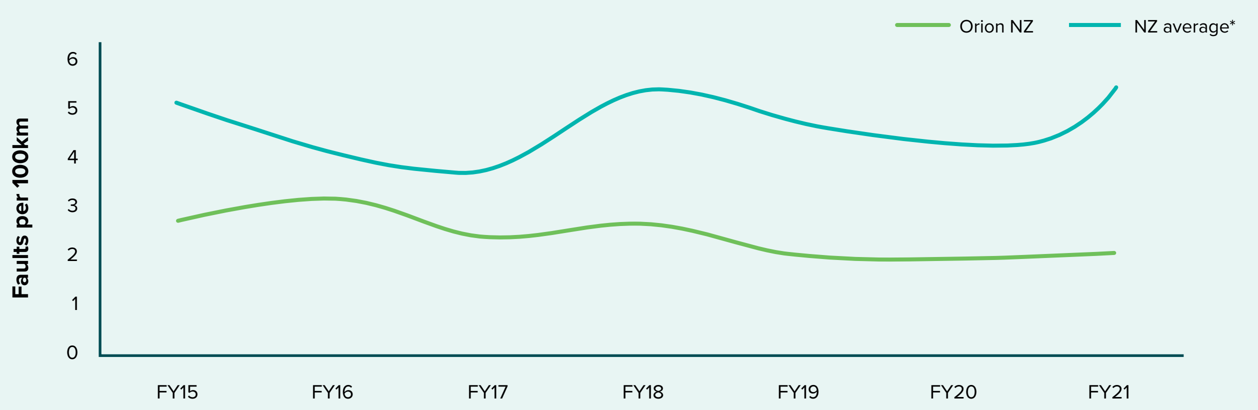
The condition of these cables are largely assessed by monitoring any failures. Condition testing of a sample of varying cable types and ages has been undertaken using the partial discharge mapping technique. A limited amount of partial discharge was noticeable in a few joints. However, there were no major areas of concern. This indicates that our cables are in good condition.

7.8.3.2 Reliability

In FY20, 11kV cable faults contributed to 18% of the total SAIDI and 29% of the total SAIFI. In recent years, the majority of failures have occurred in a joint section of the cable and half of these are located in or near Christchurch's Residential Red Zone. Options for the future of Residential Red Zone land are being explored with the community, led by Christchurch City Council. In the meantime, we are maintaining this network until its future is decided.

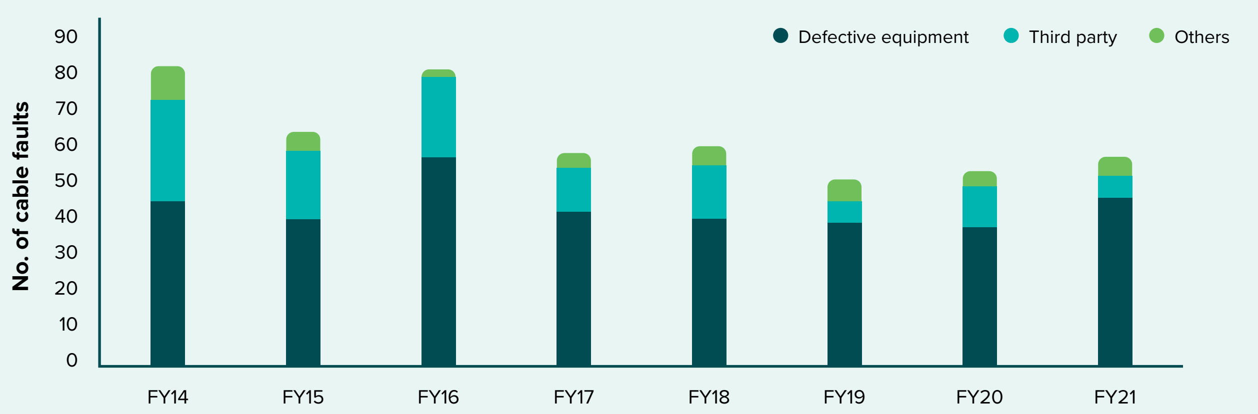
Our termination maintenance programmes have been effective in keeping the failure numbers low. The number of cable, joint and termination failures, excluding earthquakes, is shown in Figure 7.8.3. 'Others' refers to vehicle collision and weather related events where it caused a failure on the underground to overhead termination located on a pole. It also includes underground faults where the cause is unknown.

Figure 7.8.2 Number of 11kV underground cable failures and the corresponding SAIDI and SAIFI



* Source: PwC Electricity Line Business Information Disclosure Compendium 2015-2021

Figure 7.8.3 Cause of 11kV cable faults



We have seen a downward trend in third party cable strikes and other failure modes since 2014. This is due to a combination of improved excavation compliance from third party service providers, repair of earthquake damage being completed and the proactive maintenance of susceptible cable terminations. We believe the current number of failures and performance is satisfactory. The majority of 11kV cable failure is broken down to approximately 35% joint, 55% run of the cable and 10% termination. It appears that the underlying cause of failure could be due to joints reaching end of life. 'Run of the cable' failure is due to harsh environment, damaged from latent third party activity or poor insulation quality.

7.8.3.3 Issues and controls

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 11kV cable failure control

Common failure cause	Known issues	Control measures
Workmanship	Termination and joint failures can occur due to poor workmanship. It can lead to partial discharge which if not detected can cause explosive failure resulting in an outage and possible safety and environmental 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 external service providers to minimise the risk of cable disturbance while digging in close proximity to network cables Orange coloured sheath cables are installed to allow easier identification We undertake inspections during the laying of cables Proactive promotion to service providers of cable maps and locating services No joints are allowed within road intersections

7.8.4 Maintenance plan

We have programmes to address identified failure modes of cables. These failure modes have been predominately related to the terminations. Although failure rates are beginning to decrease, increased service provider costs mean our expenditure on this emergency work is not reducing.

The maintenance plan is shown in Table 7.8.3.

Table 7.8.3 11kV cable maintenance plan

Maintenance activity	Strategy	Frequency
MSU terminations	Inspections of MSU terminations, reporting grease terms and corona discharge	6 months
Diagnostic cable testing	Partial discharge and Tan Delta testing	Targeted ongoing

7.8 Underground cables – distribution 11kV continued

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 7.8.4.

Table 7.8.4 11kV underground operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	**17,000**
Routine and corrective maintenance and inspections	400	400	400	450	450	450	450	450	450	450	**4,350**
Total	**2,100**	**2,100**	**2,100**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**2,150**	**21,350**

7.8.5 Replacement plan

Any significant cable replacements will be undertaken as part of other works such as a reinforcement/switchgear replacement project or a local authority driven underground conversion project.

Some expenditure is forecast annually to allow for the replacement of short sections (<100m) of 11kV underground cable identified as being unreliable. These sections are predominantly in earthquake damaged areas.

Additional 11kV cables are installed as a result of the following:

- reinforcement plans – refer to Section 6 – Network development proposals
- conversion from overhead to underground as directed by Christchurch City and Selwyn District Councils
- developments as a result of new connections and subdivisions

An annual forecast of cable replacement capital expenditure in the Commerce Commission categories is shown in Table 7.8.5.

Table 7.8.5 11kV underground replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Distribution & LV cables	250	50	50	100	100	1,200	1,200	1,200	1,200	1,200	**6,550**
Total	**250**	**50**	**50**	**100**	**100**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**6,550**

7.8.5.1 Disposal

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. Our network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

Our 400V cable network is 3,262km and delivers electricity to street lights and customer's premises largely in Region A.

7.9 Underground cables – distribution 400V

7.9.1 Summary

Our 400V cable network delivers electricity to street lights and customer's premises largely in Region A. We also have around 60,000 distribution cabinets and distribution boxes installed on our 400V cable network. Generally, this cable network, cabinets and boxes are in good condition. We are currently in the process of carrying out a supply fuse relocation programme to increase safety for our customers and the public.

7.9.2 Asset description

The 400V underground asset class comprises two distinct subsets: LV cables and LV enclosures.

LV cables

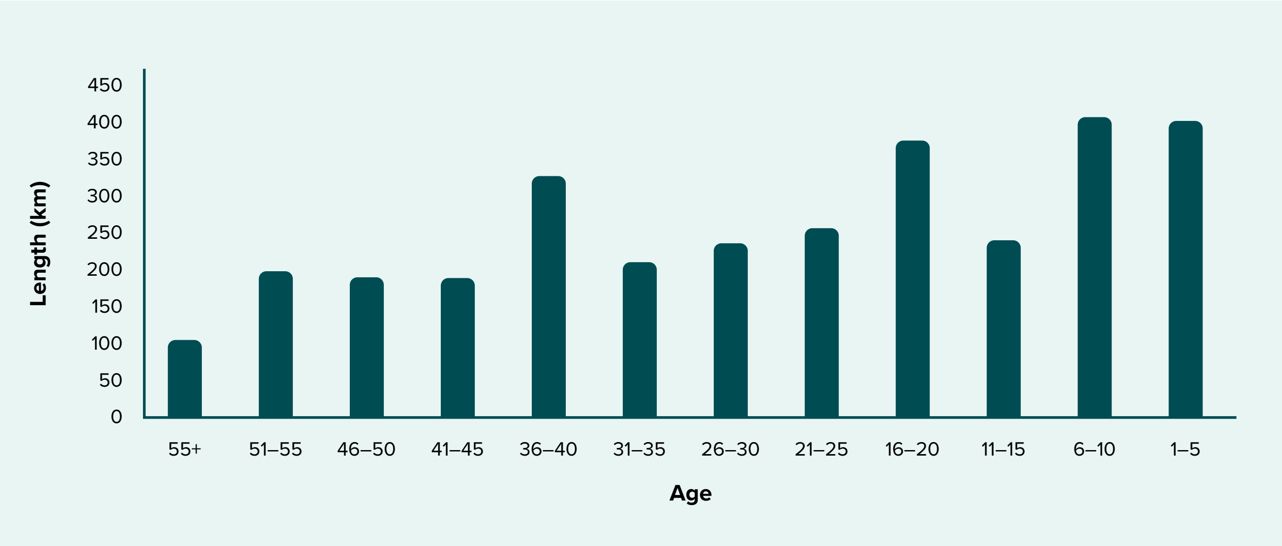
We have two groups of cables: distribution cables and street-lighting cables as shown in Table 7.9.1. They are:

- **Distribution cables –** the earlier cables are of paper/lead construction. PVC insulation was introduced in 1966 to replace some PILCA cables. XLPE insulation was introduced in 1974, mainly because it has better thermal properties than PVC
- **Street-lighting cables –** approximately 60% of this cable is included as a fifth core within 400V distribution cables

Table 7.9.1 400V cable and street-lighting networks cable type

Cable type	Length (km)
PVC	601
PILCA	387
XLPE	2,147
Total	**3,135**
Street-lighting cable	2,804

Figure 7.9.1 LV cable age profile



LV enclosures

We have two groups of enclosures, see Table 7.9.2. They are:

- **Distribution cabinets –** these cabinets allow the system to be reconfigured if each radial feeder is capable of supplying or being supplied from the feeder adjacent to it. There are two types: steel and PVC cover on a steel frame
- **Distribution boxes –** generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service and all are above ground. The majority are a PVC cover on a steel base frame, although some older types are concrete or steel

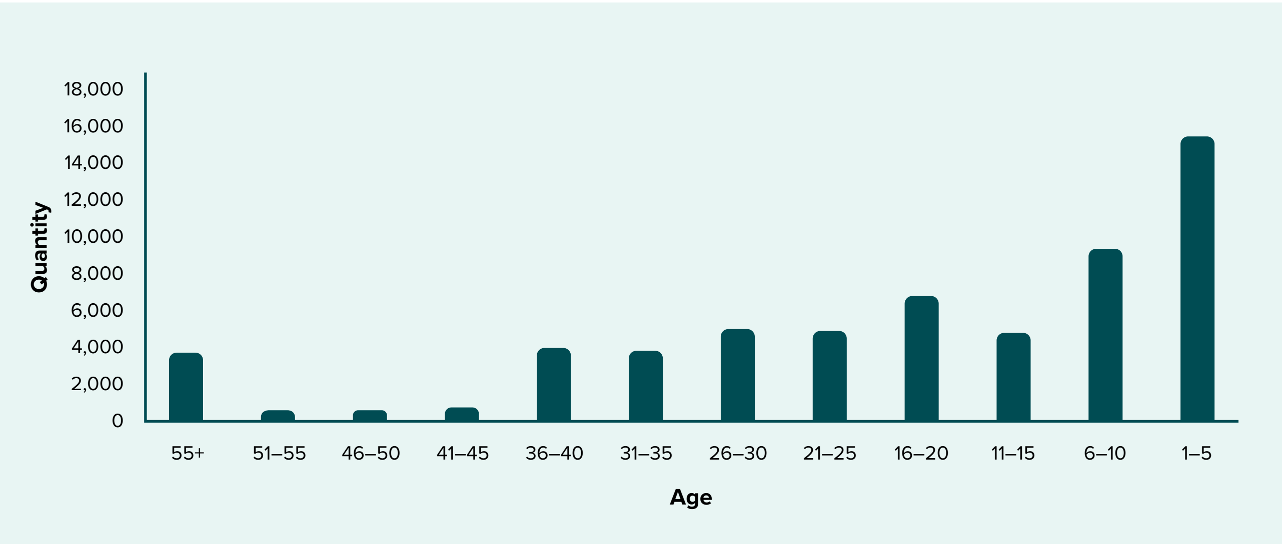
The age profile is shown in Figure 7.9.2.

We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract.

Table 7.9.2 Distribution enclosure type

Distribution enclosure type	Quantity
Distribution cabinet	6,604
Distribution box	53,217
Total	**59,821**

Figure 7.9.2 LV enclosures age profile



7.9.3 Asset health

7.9.3.1 Condition

The vast majority of our distribution cabinets and boxes are in good condition. We inspect our distribution cabinets and boxes every five years, with any defects remedied in a subsequent contract. We cannot readily inspect the condition of the LV underground cables. Based on our assessments of expected service life, fleet age and failure analysis we estimate the overall condition of the LV underground cables to be good.

However, recent modelling of our LV networks has indicated that some cables are operating above rated capacity which can reduce asset lifespan. We have allocated additional budget to upgrade our LV network cables in the areas identified to relieve constraints. See Section 6.6.2.2 for details.

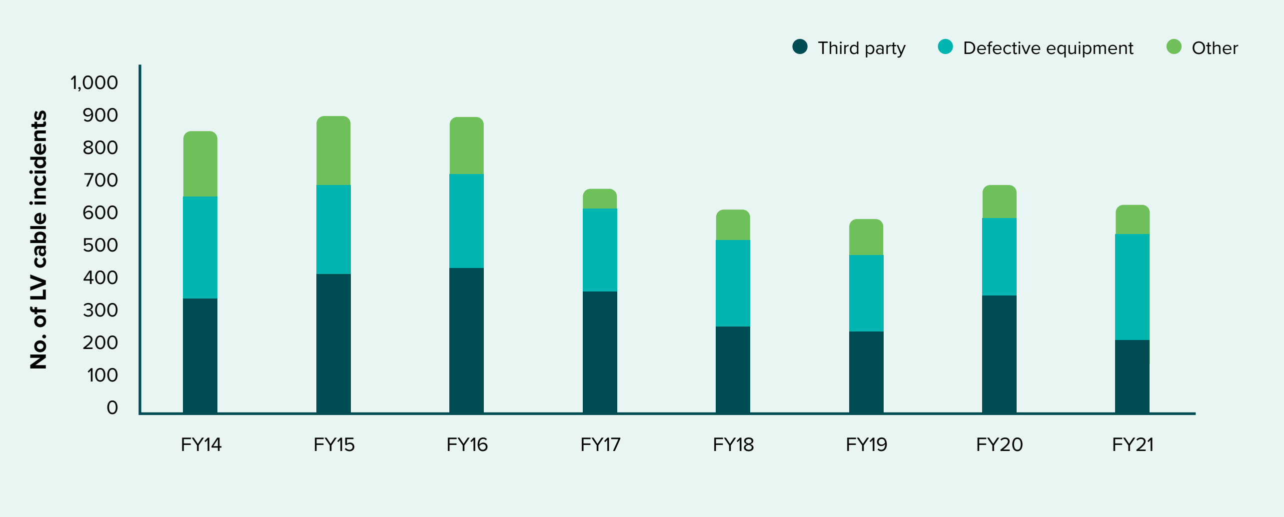
7.9 Underground cables – distribution 400V continued

7.9.3.2 Reliability

We are not required to record SAIDI/SAIFI for our LV networks. However, for prudent asset management and to ensure we maintain an acceptable service to our customers we collect performance data on our LV system. The number of LV underground call-outs our service providers address under emergency maintenance is shown in Figure 7.9.3. The majority of call-outs relate to third party damage and service or network cable failures.

Overall, our LV cable network performs well and we are seeing a downward trend in incidents on our LV underground cable. The other faults captured are mostly faults with street lighting which is owned by the Christchurch City Council. An Orion operator is normally called to attend the site for faults with street lighting.

Figure 7.9.3 Cause of LV cable incidents



7.9.3.3 Issues and controls

Table 7.9.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.9.3 LV cable network failure controls

Common failure cause	Known issues	Control measures
Material degradation	Quality of workmanship installing cable joints and terminations	Regular inspections. Cable jointers are qualified, competent and trained to install specific products
	Historically many customer service cables were connected directly to the underground network cables by way of a tee joint with the customer protection fuses in their meterbox	For increased safety we have introduced a supply fuse relocation programme where these fuses are moved to newly installed distribution boxes on the property boundary
Third party activities	Third parties dig up and damage our cables and road reconstruction	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 coloured sheath to allow easier identification Extensive public safety advertising campaigns

7.9.4 Maintenance plan

Our scheduled maintenance plan is summarised in Table 7.9.4 and the associated expenditure in the Commerce Commission categories is shown in Table 7.9.5.

Table 7.9.4 400V underground maintenance plan

Asset	Maintenance Description	Frequency
Distribution cables	Visual inspection of insulation on cable to overhead terminations. Where insulation is degraded due to the effects of UV light it is scheduled for rectification	5 years
Distribution enclosures	Visual inspection programme of the above-ground equipment and terminations. Major defects identified and scheduled for rectification	5 years

Table 7.9.5 400V underground operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	**16,000**
Routine and corrective maintenance and inspections	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	1,295	**12,950**
Total	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**2,895**	**28,950**

7.9.5 Replacement plan

We have developed a programme to install distribution boxes complete with fusing on the supply. This project is programmed to be complete in 2027. We are also upgrading our existing distribution cabinets to a more secure design. Placeholders have been put in for end of life cable replacement project for FY28 and beyond. It is expected that due to EV take-up and the move to electrification of process heat, we will need to complete end of life replacement of both the LV and distribution networks by 2030, depending on the rate at which New Zealand decarbonizes its economy. A detailed breakdown of replacement expenditure in the Commerce Commission categories is shown in Table 7.9.6.

Table 7.9.6 400V underground replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Distribution and LV cables	520	520	520	570	570	1,970	2,240	2,442	2,587	2,549	**14,488**
Other reliability, safety and environment	10,125	6,750	6,750	6,750	4,307	-	-	-	-	-	**34,682**
Total	**10,645**	**7,270**	**7,270**	**7,320**	**4,877**	**1,970**	**2,240**	**2,442**	**2,587**	**2,549**	**49,170**

7.9.5.1 Disposal plan

Our asset design standards for underground cable contain information on how to risk assess works in and around potentially contaminated land, and mandates the use of suitably qualified and experienced personnel to advise on appropriate disposal options where required. Our network specification details disposal requirements and options for all work relating to excavations, backfilling, restoration and reinstatement of surfaces.

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network.

7.10 Switchgear

7.10.1 Summary

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network. Most of our switchgear is in good condition and overall meeting our service level targets. We manage the performance of the fleet through routine maintenance and inspections. Our replacement programmes manage an aging population of oil filled circuit breakers and other switchgear with a poor health index. Our MSU replacement programme continues to grow to manage the aging population.

7.10.2 Asset description

In this section we discuss the types of circuit breaker and switchgear we install on Orion's network.

Circuit breakers

Circuit breakers are installed to provide safe interruption of both fault and load currents, for example, during power system abnormalities. They are strategically placed in the network for line/cable, transformer and ripple plant protection.

Table 7.10.1 Circuit breaker description by type

Voltage	Type	Description
66kV	Circuit breaker (zone substation)	These are installed at zone substations predominately in outdoor switchyards. The exceptions being Armagh, Dallington, Marshland, McFaddens, Lancaster and Waimakariri zone substations where the 'outdoor design' circuit breakers have been installed indoors in specially designed buildings. The majority of our 66kV circuit breakers use SF_6 gas as the interruption medium.
33kV	Circuit breaker (zone substation)	A mix of outdoor and indoor. Those installed pre-circa 2001 are mainly outdoor minimum oil interruption type. We are now moving from outdoor to indoor switchgear. Where suitable we now install indoor metal clad circuit breaker switchboards. These circuit breakers have the advantage of improved security and public safety. Since 2018, installed indoor circuit breakers have been rated for full arc containment, providing an increased level of safety.
11kV	Circuit breaker	Substation circuit breakers are installed indoors and used for the protection of primary equipment and the distribution network. The older units use oil or SF_6 gas as an interruption medium, while those installed since 1992 are a vacuum interruption type. Circuit breakers installed since 2019 are rated for full arc containment, providing an increased level of safety.
11kV	Line circuit breaker (pole mounted)	These have reclose capability. They are installed in selected locations to improve feeder reliability by isolating a portion of the overall substation feeder.

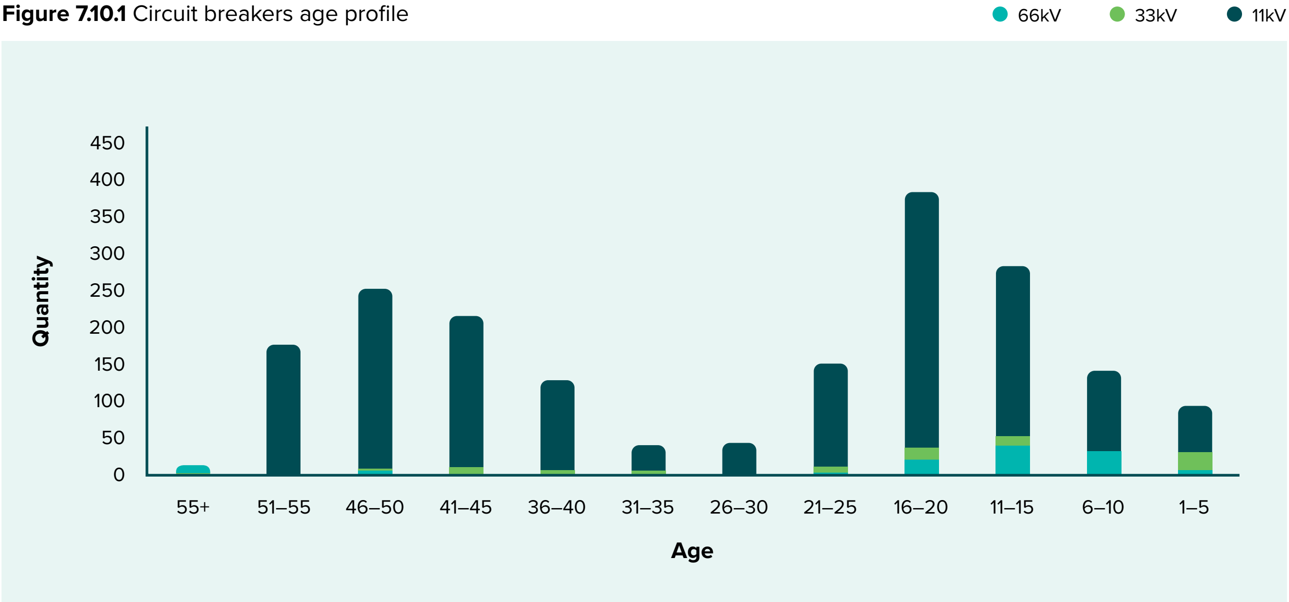
Table 7.10.2 Circuit breaker quantities by type

Voltage	Asset Type	Quantity
66kV	Oil	10
	SF_6	103
33kV	Oil	24
	SF_6	6
	Vacuum	49
11kV	Oil	669
	SF_6	34
	Vacuum	821
	Total	**1,716**

Most of our switchgear is in good condition and overall, are meeting our service level targets.

Figure 7.10.1 shows the age profile for our circuit breakers. There is a large portion of aged 11kV circuit breakers and a number of aging 33kV and 66kV circuit breakers.

Figure 7.10.1 Circuit breakers age profile



Switches

Switches are used to de-energise equipment and provide isolation points so our service providers can access equipment to carry out maintenance or emergency repairs. The type of switches are described in Table 7.10.3.

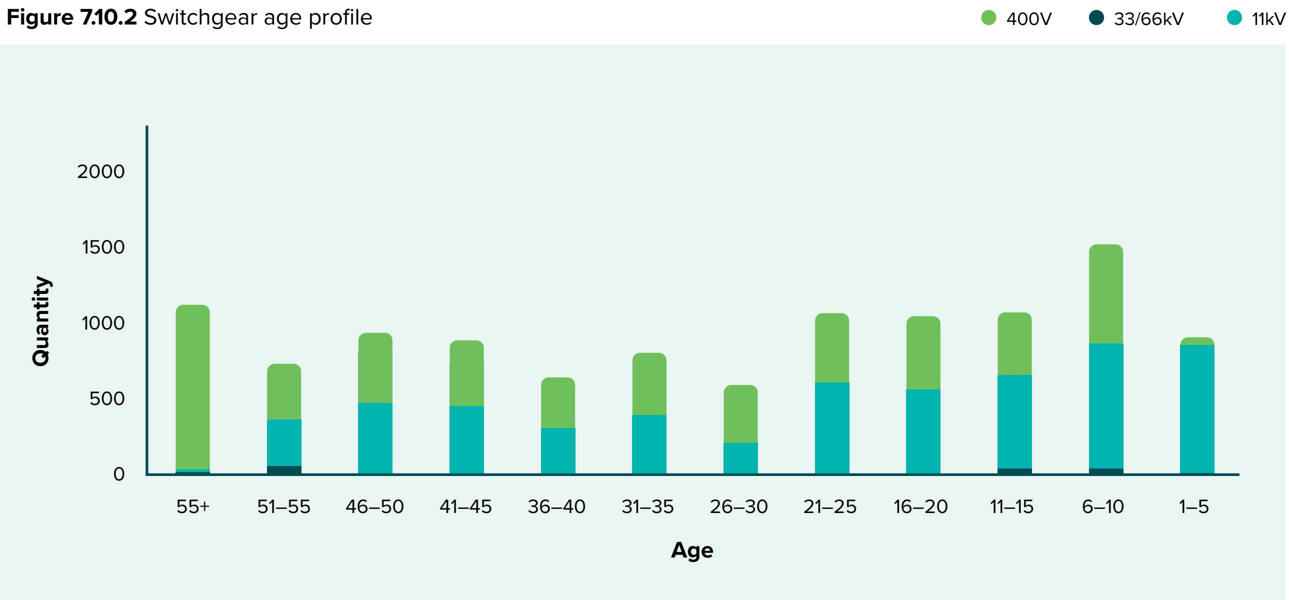
Table 7.10.3 Switchgear description by type

Voltage	Type	Description
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. Historically we installed simple hand operated devices, but since 2016, we have typically installed motor operated disconnectors which are safer, as the operator can maintain a safe distance during switching.
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 line switches.
	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.
11kV	Magnefix Ring Main Switching Unit (MSU)	MSU are independent manually operated, quick-make, quick-break design with all live parts fully enclosed in cast resin. Normally all three phases are operated simultaneously with a three phase bridge, but can be switched individually if necessary. These switches are the predominant type installed in our 11kV cable distribution network.
	Ring-main unit (RMU)	These units are fully enclosed metal-clad 11kV switchgear. 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. They are designed for arc fault containment, which ensures a high level of safety in the rare event of asset failure.
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.

Table 7.10.4 Switch quantities by type

Voltage	Asset Type	Quantity
66kV / 33kV	Substation disconnector	321
33kV	Line ABI	8
11kV	Line switch	237
	Line ABI	579
	MSU	4,610
	RMU	152
400V	Low voltage switches	5,485
	Total	**11,392**

Figure 7.10.2 Switchgear age profile



7.10.3 Asset health

7.10.3.1 Condition

Overall our circuit breaker fleet is in good working condition. Methods of condition monitoring, for example, partial discharge measurement has enabled us to detect defects at an early stage. The line switches, ring-main units and low voltage switches are generally in good condition. A technical investigation on a sample of our MSU switchgear in 2020 helped us better establish their end of life criteria and expected life. The condition of our line ABIs on the network is also good. However, some older types are reaching the end of their reliable service life.

A technical investigation on a sample of our MSU switchgear in 2020 helped us better establish their end of life criteria and expected life.

Figure 7.10.3 33kV / 66kV circuit breaker condition profile

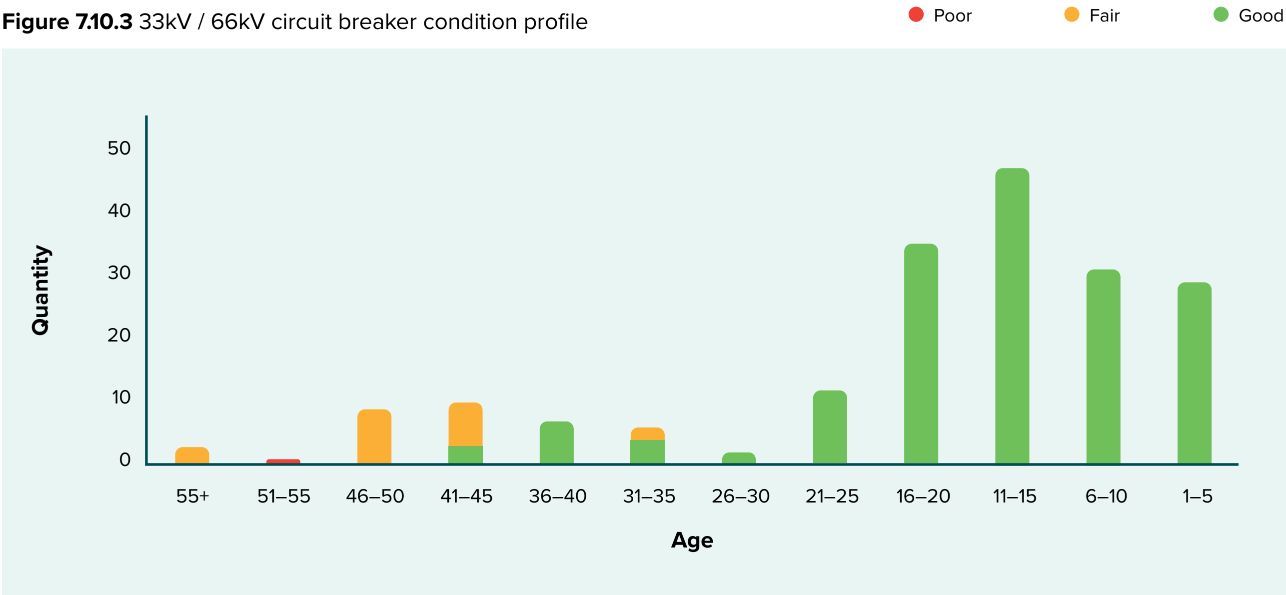
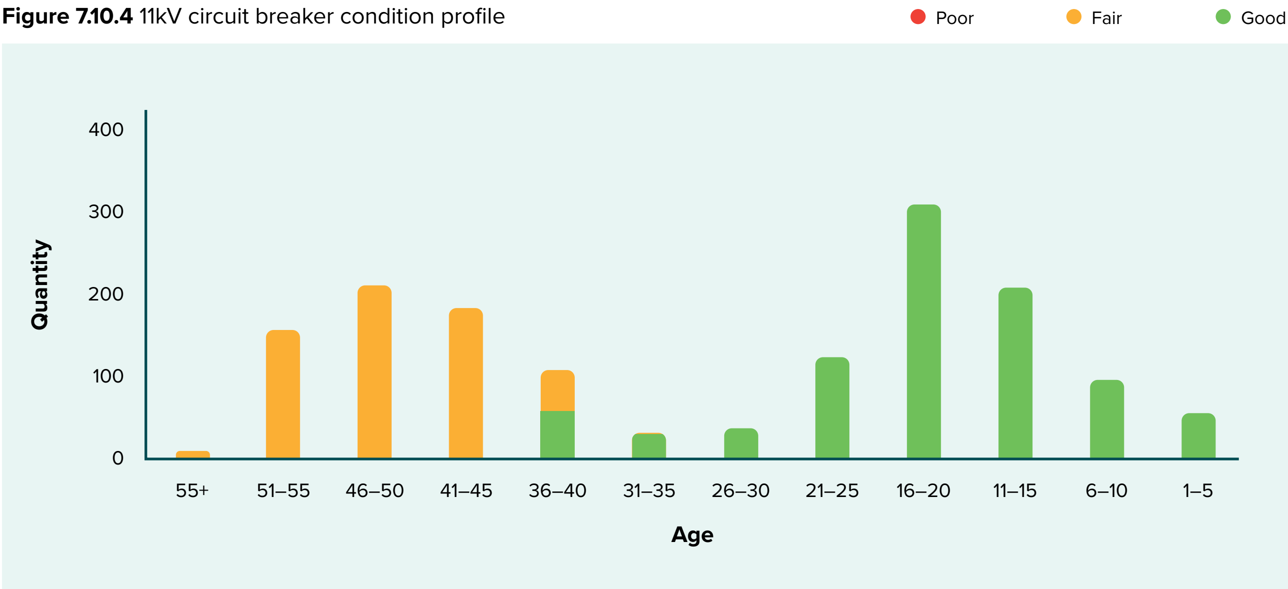


Figure 7.10.4 11kV circuit breaker condition profile



7.10.3.2 Reliability

Switchgear contributes to our asset management objectives by providing capability to control, protect and configure the electricity network. Therefore, we strive for a good performance due to the potentially serious consequences of asset failure.

Our approach for this asset class is to achieve a high level of reliability, mitigate safety and environmental hazards, and to avoid major failures. A summary of switchgear performance by type is shown in Table 7.10.5.

Table 7.10.5 Performance of switchgear

Voltage	Asset Type	Performance
66kV / 33kV	Substation disconnectors	Overall the performance level has been satisfactory. 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	The overall performance of our 33kV and 66kV circuit breakers is good. Our SF_6 circuit breakers are aging and part of the aging process is weathering of the gaskets. This causes the gaskets to harden which weakens their ability to maintain a seal. We have initiated a maintenance programme to replace gaskets and o-rings for our SF_6 circuit breakers Overall, our 11kV circuit breaker fleet is providing satisfactory performance. Our aging oil filled 11kV circuit breakers continue to provide reliable service, however a failure of these assets could be catastrophic, with the potential to cause burns and harm to the environment. We are phasing out all oil filled circuit breakers as they reach their end of life. We replace oil filled 11kV circuit breakers with arc contained vacuum circuit breakers. These require minimal maintenance and meet modern performance, environment and safety standards
33kV	Line ABI	Our remaining units are routinely maintained and are most often performing reliably. These are progressively being replaced by line switches to allow remote control capability in preparation for a potential automatic power restoration system
11kV	Line switch	These are relatively new to our network, performing well and no defects or failures to date
	Line ABI	One model of ABI is reporting a high failure rate due to faulty insulators. Refer to Section 7.10.5.5 for the replacement programme. We are phasing out ABIs and prefers to install line switches due to the remote operation capability and lower maintenance requirements
	MSU	These units are ageing but have performed reliably. Any failure is usually due to secondary factors such as a cable termination failure. On average there has been two failures per year. The failure rate has decreased slightly in recent years. 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 panel faults. We are addressing this issue through our replacement programme
	RMU	Apart from a small number of units that have experienced internal phase to earth faults, the majority of our RMUs are performing well and are reliable. Most failures in these units are usually due to secondary factors such as cable terminations and are dealt with in our regular inspections and maintenance programmes
400V	Low voltage switches	The older 'skeleton' type panels and switches have good electrical performance, however, the exposed busbars create safety risks. We install 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

7.10.3.3 Issues and controls

Switchgear failures are rare, but if they fail they have a high potential to pose a safety risk to our staff and service providers. Table 7.10.6 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures. These controls enable us to maintain a safe, reliable, resilient system and protect the environment as set out in our asset management strategic drivers in Section 2.8.

Table 7.10.6 Switchgear failure controls

Common failure cause	Known issues	Control measures
Insulation deterioration	Aging insulation medium (e.g. oil), insulation medium leakage (both oil and SF_6) and moisture in insulation medium	Partial discharge testing and monitoring programme Targeted reliability-based maintenance programme Repair and refurbishment if possible Replacement if ongoing maintenance and refurbishment is not economical or not possible
	Insulation integrity has failed on a small number of RMUs manufactured in 2014	The RMUs do not present a significant safety risk to our people or public. The cause and solution are still under investigation
Breaker contact surface degradation	MSU contacts in coastal areas are particularly susceptible to corrosion	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 programme Routine maintenance programme of cleaning, repair and/or re-termination
Mechanical failure	Stiction of mechanism from prolonged inactivity. Aging, wear and fatigue	Routine maintenance to prevent failure. Repair if economical and spares available. If not, then replacement is the only option
Pests and vermin	Bird strikes on outdoor circuit breaker due to insufficient clearances	Planned replacement and design for sufficient clearances

7.10.4 Maintenance plan

We use both routine and reliability based inspection and maintenance for our circuit breakers and switchgear. The routine maintenance programme applies to all the assets in this category. Reliability based programme is additional inspection, testing and maintenance work targeted at assets with poorer condition or reliability to maintain their performance and mitigate against failure. Inspections, testing and major maintenance are carried out at regular intervals as shown in Table 7.10.7.

Table 7.10.7 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	6 months	4 years
RMU	Inspect and report defects	2 months (Zone) 6 months (Distribution)	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 & 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 & 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. Our SCADA provides initial indication of problems	12 months	8 years

An annual forecast of operational expenditure in the Commerce Commission categories is shown in Table 7.10.8. The 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

Table 7.10.8 Switchgear operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	362	362	362	362	362	362	362	362	362	362	**3,620**
Routine and corrective maintenance and inspections	1,429	1,369	1,339	1,359	1,369	1,446	1,431	1,506	1,471	1,421	**14,140**
Total	**1,791**	**1,731**	**1,701**	**1,721**	**1,731**	**1,808**	**1,793**	**1,868**	**1,833**	**1,783**	**17,760**

7.10.5 Replacement plan

We have a proactive replacement programme for our switchgear where higher risk assets are replaced first.

On average we expect our circuit breakers to last 50 to 55 years. We have an ageing asset fleet for certain types of switchgear and we balance replacing assets too soon with our resource availability.

We prioritise replacement using a risk-based approach.

All circuit breakers have been reviewed based on several factors such as safety, condition, performance, criticality and operation.

Safety issues are given a high weighting to ensure protection of the public, employees and service providers. Performance and asset condition are considered on an individual basis and are used to develop the replacement programme.

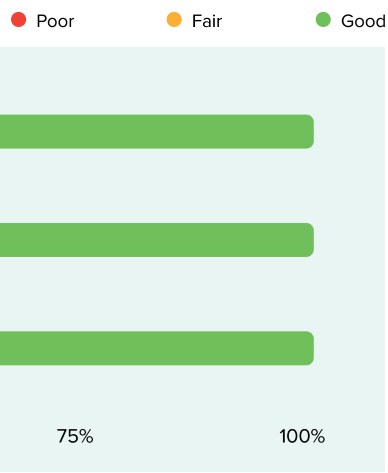
The criticality and location, i.e., zone substation, is also considered and factored into the programme.

Older circuit breakers are normally replaced with a modern equivalent, however in some cases they are replaced with a high voltage switch if it is deemed suitable. The replacement programme is regularly reviewed to consider the changing requirements of the network.

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 (Figure 7.10.5).

Figure 7.10.5 33kV / 66kV circuit breaker health scenarios



- **Do nothing scenario –** as a means of comparison, we looked at a theoretical scenario without a replacement programme. This showed the risk of a major failure of circuit breakers would increase. This poses a risk on safety of personnel and environmental impacts, which is unacceptable as it would breach a number of our asset management objectives and service level targets.
- **Planned renewal scenario –** shows the circuit breaker health profile improves over the 10-year period as we continue to replace the assets as they approach the end of their reliable life. This health profile also includes asset replacement driven by network growth.

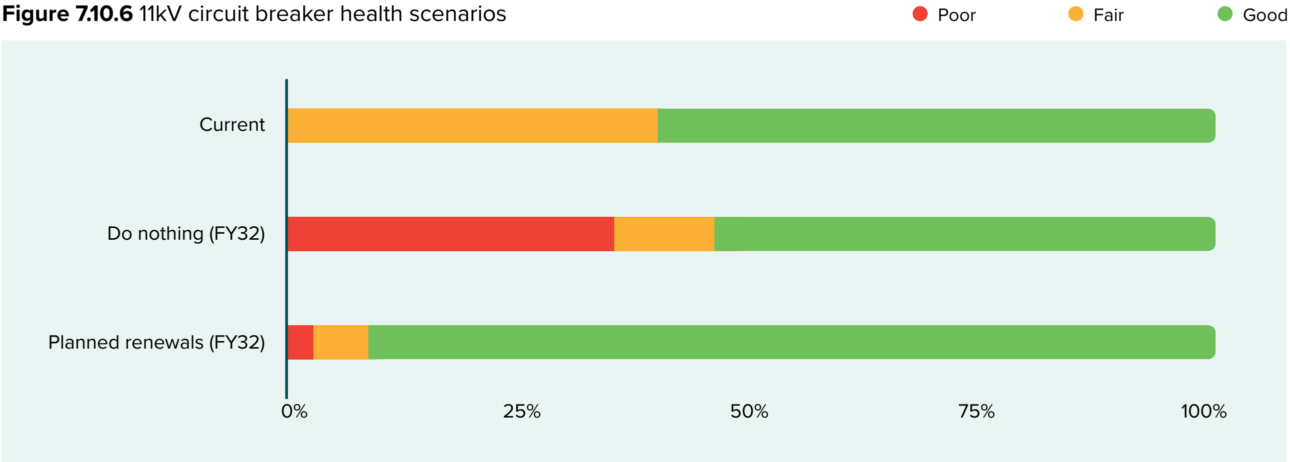
11kV circuit breakers

The scenario in Figure 7.10.6 represents the health comparison of our current versus future 11kV circuit breaker fleet. We have a large population of older oil filled circuit breakers due for renewal over the AMP period. Their replacement is an appropriate response to minimise the potential safety risks of ageing 11kV circuit breakers. The small proportion of "planned renewals" that are shown as poor health present a relatively low risk and will be replaced just outside of this AMP period.

During the past 12 months we completed 11kV circuit breaker replacement at Oxford-Tuam zone substation.

Over the next 12 months we plan to complete 11kV circuit breaker replacement at our Heathcote zone substation and commence 11kV circuit breaker replacement at Hawthornden zone substation. We also have an ongoing circuit breaker replacement programme for our distribution circuit breakers. These are usually replaced with RMUs or MSUs. In the next 12 months we plan to carry out replacement at five distribution substation sites.

Figure 7.10.6 11kV circuit breaker health scenarios



66kV / 33kV substation disconnectors

For these assets, we observe condition and risk scenarios with CBRM modelling. Older wedge type disconnectors can have alignment issues, so we are prioritising replacement of these to lower maintenance requirements and improve operational performance.

33kV line ABI

Our small population of 33kV ABI are progressively being replaced by line switches. Replacement is based on their condition and criticality, but it is planned to be a steady number over the next four years.

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 switchgear

MSU replacement is based on a combination of age and risk. The aged based replacement targets MSUs that are near end of life and, risk-based replacement targets unfused MSUs that won't provide adequate arch flash protection in the event of an LV flash over. Over half of the unfused MSUs will be replaced in the next 10 years. The age-based replacement rate will increase over the next two years to maintain the health and risk profile. We will also continue to replace our oil switches for safety reasons.

Low voltage switch

Some of the older exposed bus type LV switches associated with unfused MSUs have been identified that the low voltage arc flash incident energy presents a serious hazard. We have a targeted programme to replace these units to mitigate the risk. Other LV switches that are in poor condition will be replaced as part of the switchgear renewal works. It is anticipated that the replacement rate of LV switches will increase over the next two years and remain constant for the remainder of the 10 year period.

An annual forecast for our replacement capital expenditure in the Commerce Commission categories is shown in Table 7.10.9.

7.10 Switchgear continued

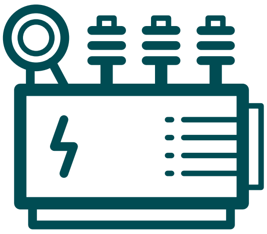
Table 7.10.9 Switchgear replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtrans-mission	30	30	30	-	-	-	-	-	-	-	**90**
Zone substation	3,338	389	1,288	5,384	6,255	2,707	910	2,922	1,660	1,053	**25,906**
Distribution switchgear	6,424	7,134	7,673	8,748	9,113	10,567	10,967	11,512	11,987	12,229	**96,354**
Total	**9,792**	**7,553**	**8,991**	**14,132**	**15,368**	**13,274**	**11,877**	**14,434**	**13,647**	**13,282**	**122,350**

7.10.5.1 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).



We have 81 power transformers installed at zone substations, ranging from 2.5MVA to 60MVA.

7.11 Power transformers and voltage regulators

7.11.1 Summary

We have 81 power transformers installed at zone substations ranges from 2.5MVA to 60MVA. Our oldest transformers are ex-Transpower single phase transformers, which we plan to replace in this AMP period due to their age and condition. We also have 15 regulators installed on the network to provide voltage stability which are in good condition. We have forecast to refurbish several power transformers over the AMP period to ensure they continue their reliable service in the future.

Our oldest transformers are the ex-Transpower single phase transformers, which we plan to replace in this AMP period due to their age and condition.

7.11.2 Asset description

Transformer

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.

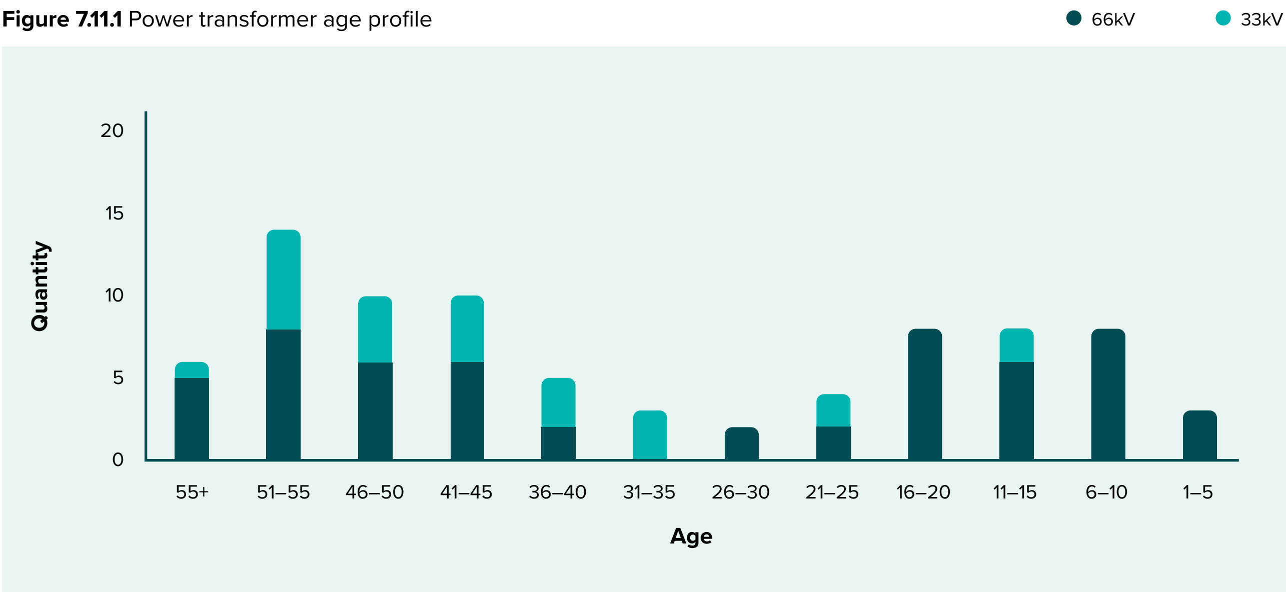
Table 7.11.1 Power transformer quantities by type

Nameplate Rating MVA	66kV	33kV
	Quantity	Quantity
30/60	2	
34/40	5	
30/36 (1Ø Banks)	2 (6)	
20/40	26	
20/30	2	
11.5/23	13	6
10/20		4
7.5/10	6	8
7.5		6
2.5		1
Total	56 (59)	25

Our power transformer age profile is shown in Figure 7.11.1. The useful life of a transformer can vary greatly. Our transformers often operate well below their nominal capacity which can lengthen their effective operating life.

We test and maintain our power transformers annually to ensure satisfactory operation. Some transformers are also refurbished to ensure we achieve the expected asset life of at least 55 years. Some of our older transformers are scheduled for replacement later in this AMP period – see Section 7.11.5.

Figure 7.11.1 Power transformer age profile



Regulators

Our 11kV line voltage regulators are installed at various locations to provide capacity via voltage regulation.

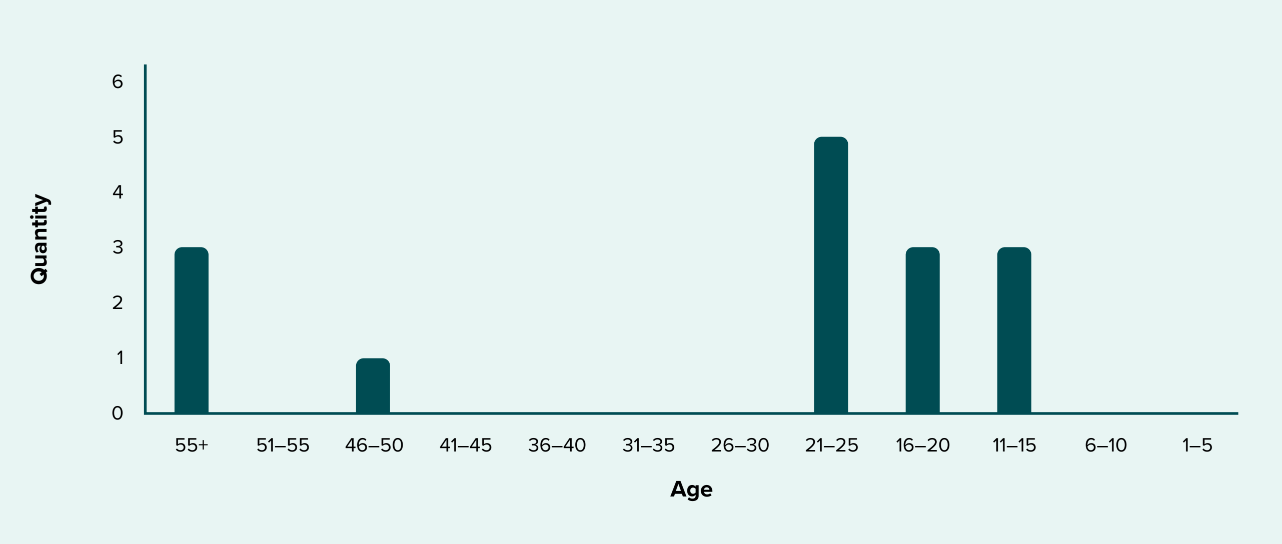
We use a wide range of ratings to cater for different load densities within our network. All regulators are oil-filled, with automatic voltage control by an on-load tap changer or induction. The quantities are listed in Table 7.11.2 and the age profile is shown in Figure 7.11.2.

Our transformers often operate well below their nominal capacity which can lengthen their asset life.

Table 7.11.2 Regulator quantities by type

Manufacturer	Nameplate rating MVA	Quantity
AEI	20	3
Siemens	4	11
Turnbull & Jones	1	1
Total		**15**

Figure 7.11.2 11kV regulator age profile



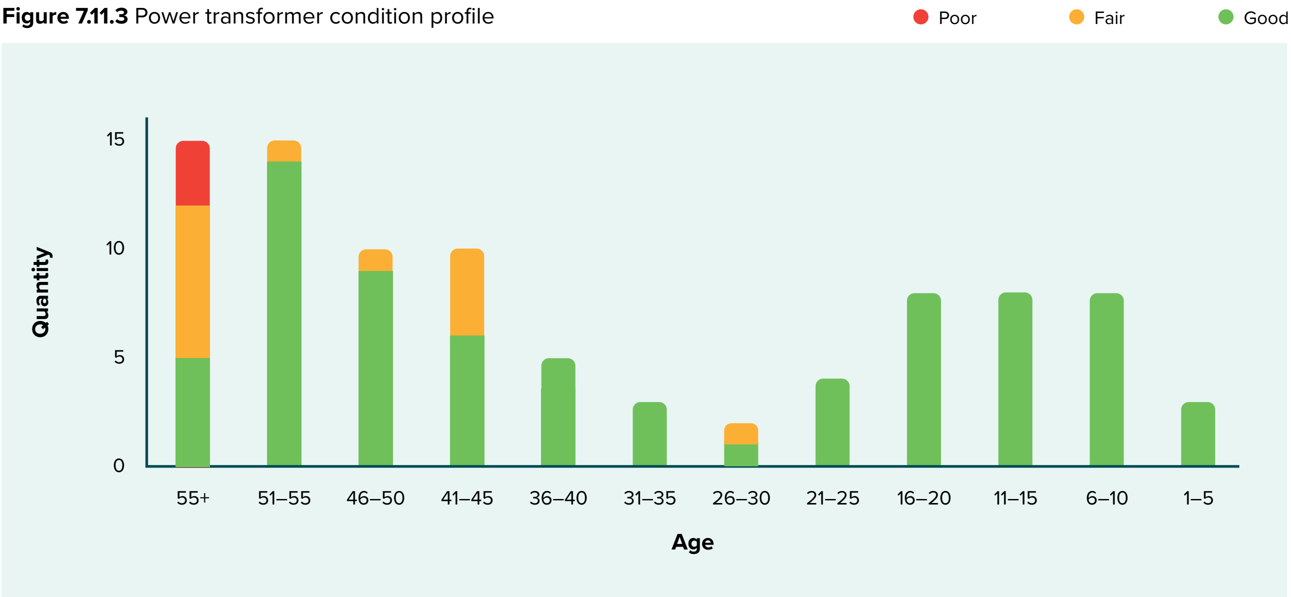
7.11.3 Asset health

7.11.3.1 Condition

Power transformers

The condition profile in Figure 7.11.3 shows that most of our transformers are in good condition. This is in part due to refurbishments we have completed on many of our older power transformers. There are a small number in poor condition. These are single phase bank transformers at Addington substation. Our strategy to address these transformers is discussed in Sections 7.11.4 and 7.11.5.

Figure 7.11.3 Power transformer condition profile



Regulators

Three 20MVA regulators at Heathcote zone substation are an older design. Two of these have been refurbished and are working satisfactorily. The condition of the other 20MVA regulator is fair and it needed repairs to the tap-changer in 2020. We will monitor the condition of this regulator to determine whether refurbishment or replacement is necessary in this AMP period.

Our fleet of 4MVA regulators is routinely maintained. While the transformer windings are still in good condition we have found some early wear out issues with the tap-changers. We have also had difficulty obtaining some spare parts. Over the next 12 months we will look at options to maintain, refurbish or replace some of these units.

7.11.3.2 Reliability

We design for N-1 transformer capability 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 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.

7.11.3.3 Issues and controls

Table 7.11.3 lists the common causes of failure and the controls implemented to reduce their likelihood.

We design for N-1 transformer capability in most situations and plan to attain a high level of reliability and resilience from this asset.

Table 7.11.3 Power transformer and regulator 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
	Moisture	Regular monitoring of the moisture in the oil Condition the oil to remove moisture (Trojan machine)
	Lightning	Surge arrestors fitted to overhead lines and switchyards
Mechanical failure	Tap changer	We specify vacuum tap changers for new power transformers as they are essentially maintenance free. Oil 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

7.11.4 Maintenance plan

Our maintenance activities shown in Table 7.11.4 are driven by a combination of time-based inspections and reliability centred maintenance.

Table 7.11.4 Power transformer maintenance plan

Maintenance activity	Strategy	Frequency	
		Regulator	Power transformer
Inspection	Minor visual inspection and functionality check	6 months	2 months
Shutdown service	Detailed inspection and functional check	4 years	Annual
Oil diagnostics	DGA and oil quality tests	4 years	Annual
Oil treatment	Online oil treatment to reduce moisture levels	4 years	2 years or more often as required
Tap changer maintenance	Intrusive maintenance and parts replacement as per manufacturer's instructions	4 years	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 years	4 or 8 years

7.11.4.1 Power transformer refurbishment

Our programme for the refurbishment of ageing transformers ensures we achieve the expected life of the asset. Where it is economic, we carry out half-life maintenance of power transformers to extend their working life and in doing so we improve service delivery and defer asset replacements. This efficiency improvement delivers on our asset management strategy focus on operational excellence. Our customers benefit from our prudent asset management through assurance of service delivery and deferred investment.

The annual forecast of power transformer and regulator operational expenditure in the Commerce Commission categories is shown in Table 7.11.5. Our forecasts are based on our assessment of transformer age, condition, and technical and financial feasibility.

Table 7.11.5 Power transformer and regulator operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Routine and corrective maintenance & inspection	335	265	265	285	275	275	275	285	275	275	**2,810**
Asset replacement and renewal	525	326	-	326	326	326	326	-	-	-	**2,155**
Total	**860**	**591**	**265**	**611**	**601**	**601**	**601**	**285**	**275**	**275**	**4,965**

7.11.5 Replacement plan

Our current replacement programme targets end of life zone substation power transformers. The programme as shown in Table 7.11.6 prevents failure rates and risk from materially increasing above current levels.

Table 7.11.6 Power transformer replacement plan

Zone substation	Details	Financial year planned
Addington	Replace T6 and T7 transformer banks. This transformer replacement timing is dependent on a wider network and site strategy to rationalise assets at the substation	FY27/FY28

Figure 7.11.4 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 unrealistic scenario is provided as a benchmark to assist in visualising the benefits of the proposed programmes. 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 7.11.4 Power transformer health scenarios

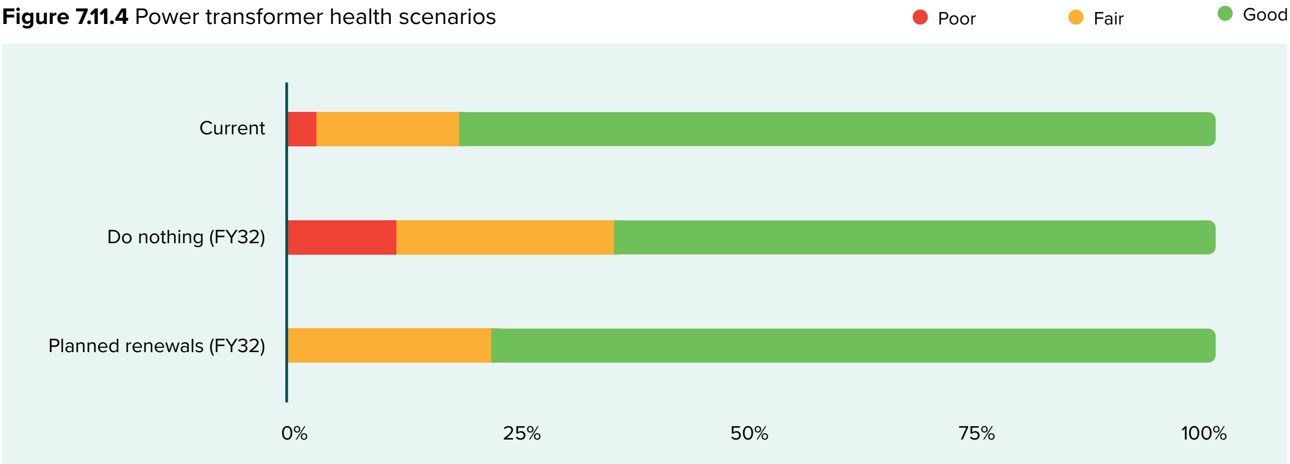


Figure 7.11.4 shows that the planned renewal scenario improves the overall condition scores of our transformer fleet. This is due to our ongoing refurbishment programme and replacement of our end of life single phase transformers. Comparing with the 'do-nothing' scenario shows that the proposed programme mitigates a substantial deterioration in asset condition. An annual summary of power transformer and regulator capital expenditure in the Commerce Commission categories is shown in Table 7.11.7.

Table 7.11.7 Power transformer and regulator replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Zone substation	20	-	-	-	1,480	2,396	-	-	-	-	**3,896**
Total	**20**	**-**	**-**	**-**	**1,480**	**2,396**	**-**	**-**	**-**	**-**	**3,896**

We have more than 11,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections.

7.12 Distribution transformers

7.12.1 Summary

We have more than 11,000 distribution transformers installed on our network to transform the voltage from 11kV to 400V for customer connections. They range in capacity from 5kVA to 1,500kVA. The performance of our distribution transformer fleet is good. We continue to maintain and replace our distribution transformers in accordance with our standard asset management practices.

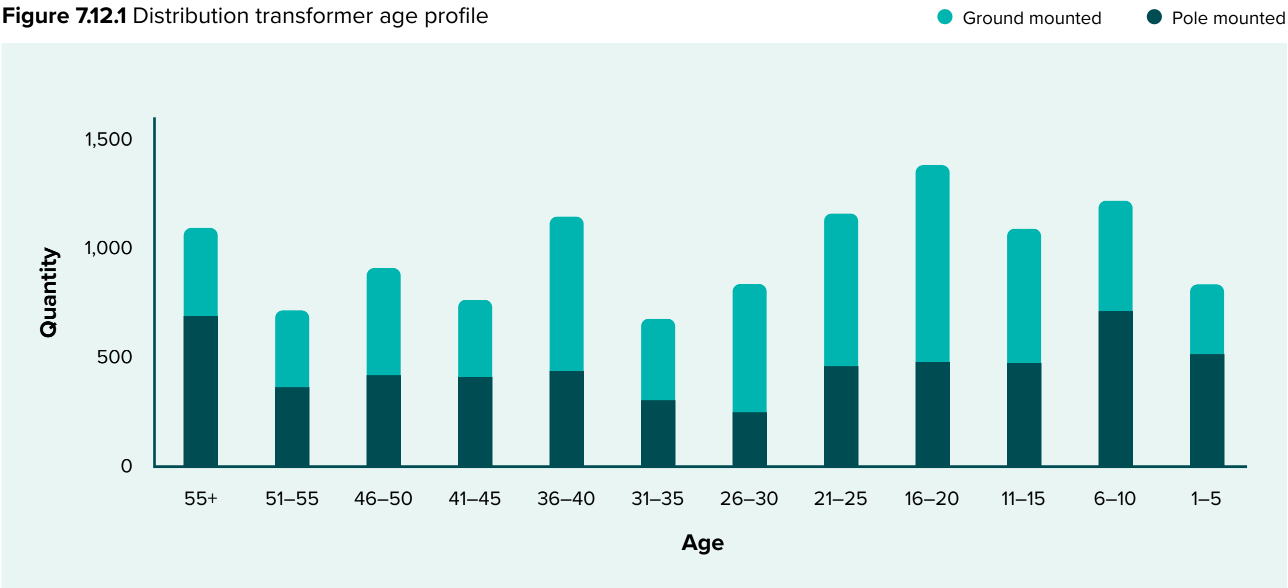
7.12.2 Asset description

Distribution transformers fall into two main categories: pole mounted or ground mounted. Pole mounted transformers range in rating from 15kVA – 300kVA. With new installations we limit pole-mount transformers to no bigger than 200kVA for safety reasons. Ground mounted transformers range in rating from 5kVA to 1,500kVA. These are installed either outdoors or inside a building/kiosk. Table 7.12.1 shows the transformer quantities categorized by rating, and an age profile can be found in Figure 7.12.1.

Table 7.12.1 Distribution transformer quantities by type

Rating kVA	Ground mount	Pole mount
	Quantity	**Quantity**
5-100	563	5,942
150-500	4,349	371
600-1000	609	
1250-1500	32	
Total	**5,553**	**6,313**

Figure 7.12.1 Distribution transformer age profile



7.12.3 Asset health

7.12.3.1 Condition

As it can be seen in Figure 7.12.2 our ground mounted distribution transformers are in good condition and are inspected on site every six months. The condition of the pole-mounted transformers varies depending on their age and location. They are only maintained, if this is considered appropriate, when removed from service for other reasons.

Our ground mounted distribution transformers are in good condition and are inspected on site every six months.

Figure 7.12.2 Distribution transformer condition profile

7.12.3.2 Reliability

The failure rate and contribution of SAIDI/SAIFI from distribution transformers is very low indicating that broadly, our current inspection, maintenance, and renewal strategies are effective. We continue to assess defects and failures, and assess our maintenance practices.

7.12.3.3 Issues and controls

Table 7.12.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.12.2 Distribution transformer failure controls

Common failure cause	Known issues	Control measures
Insulation failure	Heat	Maximum demand of larger ground mount transformers are regularly checked and replaced if overloading occurs
	Lightning	Surge arrestors fitted at cable terminations to the lines
Material degradation	Moisture ingress due to deterioration of enclosure seals Corrosion	Inspection, refurbishment and replacement programme

7.12.4 Maintenance plan

Our maintenance activities are driven by a combination of time-based inspections and reliability centred maintenance. Ground mount transformers receive regular inspections to ensure safe and reliable operation of our assets. Some on-site maintenance is carried out on transformers which are readily accessible from the ground. This work mainly relates to those within building substations that require maintenance as identified during inspection programmes.

With the exception of the building substation transformers, distribution transformers are normally maintained when they are removed from the network for loading reasons or substation works. Their condition is then assessed on a lifecycle costs basis and we decide, prior to any maintenance, whether it would be economic to replace them. If we decide to maintain them they will be improved to a state where it can be expected the transformer will give at least another 15 to 20 years of service without maintenance. This maintenance programme is shown in Table 7.12.3.

Table 7.12.3 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 mount transformers as necessary	5 years	6 months
Workshop service	Detailed inspection and testing, assess and repair defects if economic to do so	As required	As required

7.12 Distribution transformers continued

An annual forecast of our operational expenditure on distribution transformers in the Commerce Commission categories is shown in Table 7.12.4. Note that the forecast for emergencies also includes servicing power transformers and regulators.

Table 7.12.4 Distribution transformer operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	232	232	232	232	232	232	232	232	232	232	**2,320**
Routine and corrective maintenance and inspections	450	450	450	450	450	450	450	450	450	450	**4,500**
Total	**682**	**682**	**682**	**682**	**682**	**682**	**682**	**682**	**682**	**682**	**6,820**

7.12.5 Replacement plan

Transformers taken out of the network due to capacity changes or faults are replaced where repair or maintenance proves uneconomic. An allowance has been made in the replacement budget to cover this. An annual summary of our distribution transformer replacement capital expenditure in the Commerce Commission categories is shown in Table 7.12.5.

Table 7.12.5 Distribution transformer replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Distribution substations and transformers	2,112	2,466	2,346	2,868	2,468	3,341	3,151	3,331	3,460	3,427	**28,970**
Total	**2,112**	**2,466**	**2,346**	**2,868**	**2,468**	**3,341**	**3,151**	**3,331**	**3,460**	**3,427**	**28,970**

7.12.5.1 Disposal

Our network specification for distribution transformer maintenance mandates the disposal of transformers where they are beyond economic repair. The recommendation to dispose is made by our service providers and must be approved by Orion.

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults.

7.13 Protection systems

7.13.1 Summary

Our protection system consists of Intelligent Electronic Devices (IED), electromechanical relays and analogue electronic devices. Overall our protection system equipment is performing well and meeting our service target levels.

The main issues are due to asset ageing or obsolescence in equipment support, parts and function.

The reliability of the protection system is inherent in fulfilling our objectives of maintaining personnel safety and system reliability.

Protection system upgrades/replacement is most cost effective if linked to the associated switchgear replacement. For this reason, our protection system replacement programme is influenced by the volume and schedule of our switchgear replacement.

7.13.2 Asset description

Protection systems are installed to provide automatic control to elements of our network and to protect it during power system faults. The protection relays we use on our network are either electro-mechanical devices, or modern microprocessor-based intelligent electronic devices (IED). IEDs provide protection, control and metering functions integrated into a single device. The introduction of IEDs has allowed us to reduce costs by improving productivity and increasing system reliability and efficiency.

Table 7.13.1 Relay types

Relay type	Quantity
Electro-mechanical	1,036
Micro-processor based (IED)	1,751
Total	**2,787**

7.13.3 Asset health

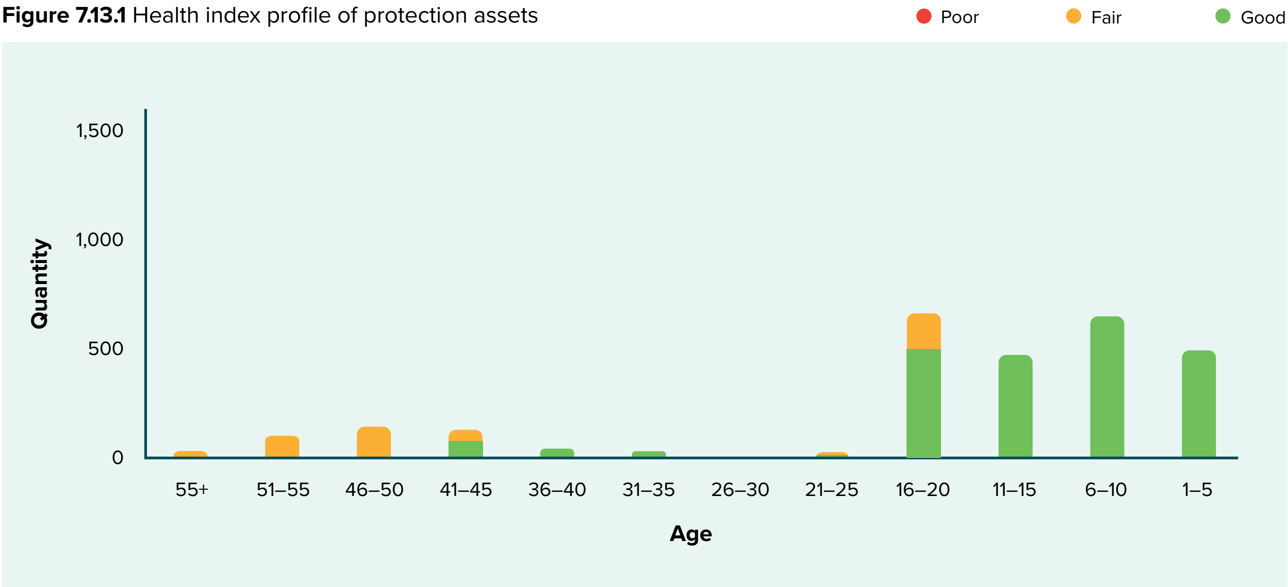
7.13.3.1 Condition

The factors that go into evaluating the protection relay health index are predominately the age but also include make/model reliability and obsolescence factors. Figure 7.13.1 shows the health index profile against the age of our protection assets.

The health profile shows that most of the protection relay population is healthy. A smaller proportion of our population have health indices in the 'Fair' range. This reflects the phase of their life when the probability of failure is increasing and requires active consideration of their replacement. These 'Fair' health index relays are mostly types with known problems or ageing electromechanical types.

We believe the levels we are achieving are appropriate as Orion is delivering on its asset management objectives and service level targets. It also is consistent with our risk appetite. Our intention with our maintenance and replacement programmes is to maintain our current asset condition and service levels.

Figure 7.13.1 Health index profile of protection assets



7.13.3.2 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 are still performing satisfactorily. This technology is employed in 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 IED relays are performing well. The main issue with our protection system is around the ageing or obsolescence of equipment, support, parts and function. As the relays age, their reliability diminishes.

7.13.3.3 Issues and controls

Protection failure can lead to longer fault durations with further potential for asset damage, larger outages 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 7.13.2 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.13.2 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
	Firmware and/or software	Up to date and stable firmware upgrades. Regular testing
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	Pest and vermin	We have vermin proofed building entries and installed vermin traps in zone substations

7.13.4 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 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 the location.

The frequency of zone substation maintenance is typically set by the installed primary asset type's insulation medium within the circuit breakers and power transformer tap changer. IED protection systems, which are generally paired to vacuum circuit breakers are thoroughly tested and maintained every eight years. Older generation protection systems which are paired to oil circuit breakers are tested and maintained every four years. Protection systems that interact with GXP protection systems are tested every four years. The frequency of inspection and maintenance by location is shown in Table 7.13.3.

7.13 Protection systems continued

Table 7.13.3 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, efficiency of fault detection and maintenance service provider costing, we forecast a stable ongoing option for maintenance work volume similar to our previous years. An annual forecast of operational expenditure on protection systems is shown in Table 7.13.4 in the Commerce Commission categories.

Table 7.13.4 Protection operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	412	412	412	412	412	412	412	412	412	412	**4,120**
Routine and corrective maintenance and inspections	490	470	470	510	490	490	490	510	490	490	**4,900**
Total	**902**	**882**	**882**	**922**	**902**	**902**	**902**	**902**	**902**	**902**	**9,020**

7.13.5 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 in conjunction with end of life switchgear is economical and efficient in terms of cost and timing for outages. This is especially 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 injury to our staff and contractors. The timing can also coincide with any other related work to be undertaken at those sites to reduce outages and more efficient usage of contracting resources.

The replacement expenditure in the Commerce Commission categories is shown in Table 7.13.5.

Table 7.13.5 Protection capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Zone substation	3,152	1,820	383	2,174	1,594	780	854	2,450	903	2,578	**16,688**
Distribution switchgear	323	187	117	162	210	83	136	287	77	55	**1,637**
Total	**3,475**	**2,007**	**500**	**2,336**	**1,804**	**863**	**990**	**2,737**	**980**	**2,633**	**18,325**

Our 1,076km of communication cables are predominantly multi-twisted-pair copper cables located in Region A.

7.14 Communication cables

7.14.1 Summary

Communication cables are primarily used for SCADA, ripple control, metering and other purposes in addition to their original function of providing unit protection communications. These cables are in good condition and we have no specific maintenance or proactive replacement plan at this stage. The majority of our existing communications cables are multi-twisted-pair copper which is an older communications technology. When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

7.14.2 Asset description

Our 1,076km of communication cables are predominantly multi-twisted-pair copper cables located in Region A. Most are armoured construction. They are laid to most building substations and are used for Unit Protection communications (pilot wire), SCADA, telephone, data services, ripple control and metering.

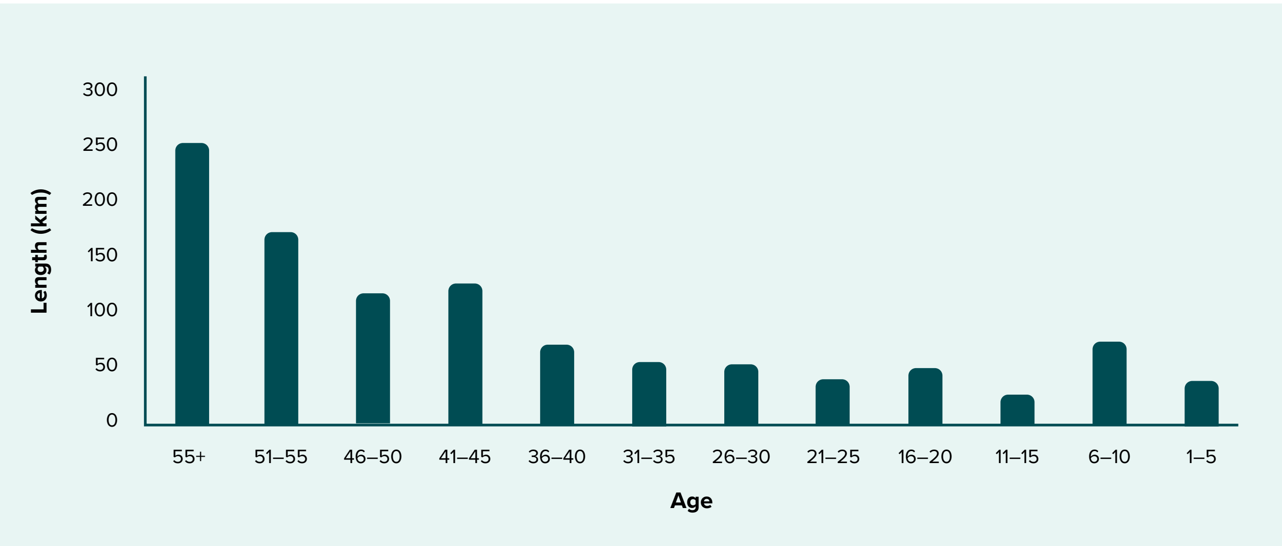
We install fibre optic communications cables, laid in ducts with all new subtransmission power cables. We also share Transpower's existing fibre-network ducts which provide us with fibre routes between our Control Centre at 565 Wairakei Rd and our zone substations. These fibre routes provide both protection signalling for various 66kV circuits, plus SCADA and other data communications.

When we require new communications routes associated with subtransmission cables or lines we now generally install fibre optic cables in ducts.

The most common and effective differential protection uses multi-twisted-pair communication cables for end-to-end measurement of electrical parameters on the protected section of cable. As new lengths of primary network cable are laid, a communication cable is laid with the electrical power cable.

The age profile of our communication cables is shown in Figure 7.14.1. The average age of these cables is 42.

Figure 7.14.1 Communication cables age profile



7.14 Communication cables continued

7.14.3 Asset health

The overall condition of our communication cables is good. A common failure point on the copper twisted-pair communication cables is the joints. These joints are epoxy filled and have two modes of failure, they are:

- The epoxy used in the old filled joints overtime becomes acidic and eats away the crimp joints leaving the cables open circuited
- Ground movement allows moisture ingress due to the inflexible nature of the epoxy.

7.14.4 Maintenance plan

No specific maintenance plan is employed for the communication cables at this stage, but circuits that are used for Unit Protection communication are routinely tested. Any identified issues are addressed as part of protection maintenance at this stage.

A forecast of the annual operational expenditure on our communication cables in the Commerce Commission categories is shown in Table 7.14.1.

Table 7.14.1 Communication cables operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	20	20	20	20	20	20	20	20	20	20	**200**
Routine and corrective maintenance & inspection	100	100	100	100	100	100	100	100	100	100	**1,000**
Total	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**1,200**

7.14.5 Replacement plan

Renewal of communication cables is based on condition results from tests carried out during the installation and commissioning of other works. The expenditure is currently volatile due to this reactive nature of replacement so our budget is based on a historical average. The replacement expenditure in the Commerce Commission categories is shown in Table 7.14.2.

Table 7.14.2 Communication cables replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Other network assets	60	60	60	60	60	60	60	60	60	60	**600**
Total	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**600**

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

Our communication network is made up of voice and data systems which provide an essential ancillary service assisting with the operation of our distribution network, and communication with our customers. These systems provide contact between our Control Room and operating staff and service providers in the field, 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 good condition and performing well. Additional control of the high voltage network and monitoring of the low voltage network is taking place. We have started to upgrade our analog radios to digital. This will provide us with significantly increased signal coverage in remote areas of the network.

We have started to upgrade our analog radios to digital. This will provide us with significantly increased signal coverage in remote areas of the network.

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 hand-held portable units. These operate via Linked VHF hilltop radio repeaters.
- **Private telephone switch** – a telephone network split between the transportable data centres, connecting to the main telco network from both locations.
- **Public cellular networks** – not owned by Orion, we use these public networks for mobile voice and data communications.

  To increase resilience, our out of office cellular site is directly connected to the Christchurch cellular switching node.

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 for main power feeds 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	Nominal asset life
SCADA analogue communication copper cable network	Used for serial communication to a small number of urban substations. Installed in dedicated pairs with one modem at the remote site connected to a remote terminal unit (RTU) and its pair at a zone substation connected to the Internet Protocol (IP) network via terminal servers. This system is due for replacement due to obsolescence.
SHDSL IP system	Used for point-to-point IP 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 sub-transmission cables and provides high speed communications paths between our SCADA, engineering network IP and corporate office.
Public cellular network	Operated with in 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	160
Voice radios	650 (includes Orion service providers')
Cellular modems/HH PDA's	323
IP data radios	327
Radio antennae	327
Antenna cable	530
Communication masts	55
Routers/switches	56
Telephone switch	2

7.15.3 Asset health

7.15.3.1 Condition

Our IP based equipment is on average no older than eight years and is in good condition. We have replacement programmes in place to replace technologies nearing the end of life.

7.15.3.2 Reliability

The SCADA IP network is very fault tolerant 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.

7.15.3.3 Issues and controls

Table 7.15.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

Table 7.15.3 Communication systems failure controls

Common failure cause	Known issues	Control measures
Infrastructure component failure	Malicious damage (shooting antennae) Weather damage (wind, snow) Lightning strike Power supply failures on radio units and base stations	Resilient infrastructure and lifecycle management Diversity of data/signal paths (rings) Octal Small Pluggable Format (OSPF) routing protocol (functional self-healing) Spares
	Human error	Training / certification Change Management
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

Regular inspections are carried out to ensure reliable operation of the communication systems. The plan is described in Table 7.15.4 and the associated expenditure in the Commerce Commission categories is shown in Table 7.15.5.

Table 7.15.4 Communication systems maintenance strategy

Asset	Maintenance activities / strategy	Frequency
Cable modems	No preventative maintenance, replaced if faulty, SHDSL modems are continuously monitored with faults attended to as soon as detected.	As required
Voice radios	No preventative maintenance, 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	No preventative maintenance, replaced if faulty, radio links are continuously monitored with faults attended to as soon as detected.	As required
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	No preventative maintenance, 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

Table 7.15.5 Communication systems operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	82	82	82	82	82	82	82	82	82	82	**820**
Routine and corrective maintenance and inspections	429	409	319	319	319	319	319	319	319	319	**3,390**
Total	**511**	**491**	**401**	**401**	**401**	**401**	**401**	**401**	**401**	**401**	**4,210**

7.15.5 Replacement plan

Because of the rapid improvement in technology, communications equipment has a relatively short life and equipment is not normally renewed but is replaced with more modern technologies. Our replacement plan over the AMP period is shown in Table 7.15.6 and the forecast expenditure in the Commerce Commission's categories can be found in Table 7.15.7.

Table 7.15.6 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.
Hill top radio facility	Because of the expansion of both UHF radio protection linking and additional UHF PowerOn communications requirements, this facility is no longer fit for purpose. It is currently being replaced with a self-supported support structure with antenna expansion capability and weather tight equipment housing structure.
Voice radios	After the successful trial of a digital radio system on the Banks Peninsula in FY20, we are now looking to upgrade our existing analog system over the next three years. The upgrade will significantly increase our coverage in remote areas and offer more features such as user identification and user location.
Comms architecture projects	As we introduce new assets on our network the need for communications increases. Expenditure is kept aside for such projects, with the majority going towards fibre installations. Currently there is no long-term plan for our comms architecture projects but going forward this is something we will look to develop.
Pole investigation	A number of our radio sites utilise steel octagonal antenna masts. Recently, there have been reports of significant movement/vibration of these poles in specific wind conditions. After consultation with a specialist mast antenna engineer, an ongoing inspection process has been put in place.

Table 7.15.7 Communication systems replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Zone substation	50	50	50	50	50	50	50	50	50	50	**500**
Other network assets	923	935	785	235	235	301	337	364	385	378	**4,878**
Quality of supply	210	210	210	210	210	84	84	84	84	84	**1,470**
Total	**1,183**	**1,195**	**1,045**	**495**	**495**	**435**	**471**	**498**	**519**	**512**	**6,848**

Because of the rapid improvement in technology, communications equipment has a relatively short life and equipment is not normally renewed but is replaced with more modern technologies.

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 built on 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 advanced distribution management system. 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 reliability measures such as SAIDI and SAIFI.

The network model used by PowerOn and the SCADA data that it relies on are currently limited to high voltage assets of 11kV or more. Our expectation is that over the next five years we will extend the model to include low voltage assets. We also intend to introduce technology that will enable the ADMS to automatically operate network equipment or self-heal to restore supply to customers following an outage. Work underway includes a Switching Request Register (SRR) to improve service provider workflows.

7.16.2 Asset description

An ADMS is a suite of applications designed to monitor and control the distribution network and also to support decision making in the Control Room. 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 Scheme (APRS). APRS allows the ADMS to autonomously operate remote switching devices to isolate faults and reconfigure the network to restore supply. We will implement the SRR to improve service providers workflow.

The network model used by PowerOn and the SCADA data that it relies on are currently limited to high voltage assets 11kV or more. Our expectation is that over the next five years we will extend the model to include low voltage assets.

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, 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 faults. 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 Contact Centre to call customers back after an interruption to confirm that their power supply has been restored.
Mobile field service management	Field services operators are equipped with iPads and receive switching instructions directly from 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	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

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 the substations. The major RTU used is at end of life and we are starting to replace them during the substation maintenance rounds.

7.16.3.2 Reliability

Generally the ADMS system runs at or near 100% reliability. There are some recent performance issues with the capacity, performance and/or availability of the ADMS and these are being addressed within our operational budgets to improve DMS operations, for example: user training, computer and network infrastructure, computer systems monitoring, settling-in time for new functionality, alarms reviews, commissioning practices, updated hardware, software updates.

7.16.3.3 Issues and controls

Our maintenance and replacement programmes are developed 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

The forecast expenditure in the Commerce Commission categories is shown in Table 7.16.3.

Table 7.16.3 ADMS operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	140	140	140	140	140	140	140	140	140	140	**1,400**
Routine and corrective maintenance and inspections	406	481	481	481	481	481	481	481	481	481	**4,735**
Total	**546**	**621**	**621**	**621**	**621**	**621**	**621**	**621**	**621**	**621**	**6,135**

7.16.5 Replacement plan

ADMS and RTU hardware capabilities, age and maintainability is reviewed annually and an assessment is made of equipment that needs to be programmed for replacement or renewal as mentioned in Section 7.16.3.1. An annual forecast of ADMS replacement capital expenditure in the Commerce Commission categories is shown in Table 7.16.4.

The expenditure is to support our plans for major upgrades for PowerOn in FY26-FY27. The expenditure also allows for analytics, automated switching, and an LV model to be integrated into PowerOn over the next four years.

Table 7.16.4 ADMS replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Zone substation	188	230	230	230	230	72	-	-	-	-	**1,180**
Other network assets	1,430	750	1,050	1,650	1,600	131	128	310	28	-	**7,077**
Total	**1,618**	**980**	**1,280**	**1,880**	**1,830**	**203**	**128**	**310**	**28**	**-**	**8,257**

7.16.6 Innovation

We have applied a continuous improvement mind-set to our SCADA and network management systems which has, through the addition of new platforms and modules, improved our capability to operate our network. This efficiency improvement links to our safe, reliable, resilient system, health and safety, capability and future network asset management strategic drivers.

Customers benefit from enhanced and cost-effective service delivery when we use state of the art systems and approaches to management of demand and system coordination to minimise capital expenditure on our network, and anticipate and maximise our response to system issues.

Our load management systems control electrical loads predominantly by injecting frequency signals over the electricity network.

7.17 Load management systems

7.17.1 Summary

Orion's load management systems control electrical loads predominantly by injecting frequency signals over the electricity network. The system is made up of various electrical plant and hardware/software platforms.

We are undertaking a review of our load management system architecture. This will look at how we control future Distributed Energy Resource Management (DERM) and consider integration of alternative metering sources further down the network including our protection relays, LV monitors and possibly LV smart meters. It is envisaged that any future change will transfer the load management functionality into our DMS system.

Our review of load management is part of a wider review that also considers signaling infrastructure – ripple control.

We are also actively involved in industry groups that are researching alternative technologies for DERM control.

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 the seven other electricity distributers in the upper South Island. These systems are described in Table 7.17.1.

The primary use of both systems is to defer energy consumption and minimise peak load. This is achieved in two ways. Customer demand management load reduction and/or generation and by distributor controlled load management through hot-water cylinder and interruptible irrigation control.

Orion's load management system signals to our customer's premises by injecting a carrier frequency with a digital signal into the power network that is acted upon by relays installed at the customer's connection point. There are two ripple carrier frequencies used on our system. The ripple relays are owned by the retailers, apart from approximately 2,000 that are owned by Orion, to control streetlights. Alternative signal means are also used to prepare and initiate some major customer load management methods.

We install new 11kV ripple injection plants in conjunction with new zone substations or rural zone substations that are converted from 33kV to 66kV.

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.	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
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.	53 RTUs and 50+ PQMs

7.17 Load management systems continued

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 system 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 planned in the first half of this AMP period.	Poor
Upper South Island load management system	This system was installed 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 on the 66kV system were installed from FY04, and some components are approaching the expected useful life of 15 years. The units have been reliable to date and spare parts are available.	Good
Ripple injection system – Region B 317Hz system	The 11kV and 33kV ripple plant injection controllers are approaching their expected service life. The manufacturer no longer supports the controller type used on the 33kV ripple plants. These units have been reliable to date and there is a complete spare plant and controller if failures occur.	Fair
Measurements	The provision of resilient (i.e., redundant) load measurement is good at most sites but has deteriorated post-earthquake. Light sensing for accurate timing of street lights has deteriorated to only a single measurement point. The measurement of loads had altered a significant amount with network changes and the redundancy of measurement is poor at some locations	Poor

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. No 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. This includes maintaining a highly resilient system and undertaking regular reviews of system capacity and performance. The level of risk for this asset class is considered to be low based on current information about the causal likelihoods and the controls with their respective effectiveness levels.

Table 7.17.3 lists the common causes of failure and the controls implemented to reduce the likelihood of these failures.

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
Information system (application/database) failure	Software failure/flaw	System monitoring, diversity, resilient platforms, maintenance contracts
Cyber Risks	Known escalation in cyber attacks world wide	Requesting extra support from supplier given that no software patches are available on sunset operating system

7.17 Load management systems continued

7.17.4 Maintenance plan

The complexity of the software and availability of technical support increase the difficulty and cost of maintaining the master station system.

Injection plants have a quarterly operational check as well as an annual inspection that includes measurement of installed capacitors and detailed tests on the inverter. Dusting and physical inspections are considered part of the annual maintenance. The operational expenditure in the Commerce Commission categories is shown in Table 7.17.5.

Table 7.17.4 Load management system maintenance plan

Asset	Maintenance activity	Frequency
Master station	Supplier review	Annual
Ripple plant	Shutdown clean, inspect and test	Annual

Table 7.17.5 Load management operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Service interruptions and emergencies	45	45	45	45	45	45	45	45	45	45	**450**
Routine and corrective maintenance and inspections	359	359	359	359	359	359	359	359	359	359	**3,590**
Total	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**4,040**

7.17.5 Replacement plan

Load management master stations
The hardware and software of the USI load management master station is ageing and the operating system is no longer supported. This system is under review for refurbishment and/or migration. As part of the review we will consider ongoing resources and the cost of Orion supporting three separate and independent SCADA systems network management, Orion load management, USI load management – and whether a consolidation of SCADA systems is viable. The work based on the review is currently planned to be carried out in FY23 and FY24.

Ripple plant and controllers
From FY23 we have a proactive replacement programme for ripple frequency controllers. The majority of these are now more than 15 years old, and we have begun to see some age-related failures. We had been deferring proactive replacement just in case an emerging technology made them redundant, however we now anticipate these will required for the medium term at least.

Table 7.17.6 Load management system replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Zone substation	440	450	460	460	450	201	224	240	224	222	**3,371**
Other network assets	770	770	70	500	570	70	70	70	-	-	**2,890**
Total	**1,210**	**1,220**	**530**	**960**	**1,020**	**271**	**294**	**310**	**224**	**222**	**6,261**

7.17.5.1 Disposal

We will retire the 33kV ripple injection plants at Moffett and Hornby substations in the near future. This will provide spares for the remaining plants at Springston and Hororata.

We manage all types of works activity using purpose-built in-house developed applications which populate a single works data repository.

7.18 Information systems

7.18.1 Summary

Our Asset Management Information Systems (AMIS) hold information about our electricity network assets and support our business processes in managing assets. Our AMIS are performing well as they are regularly maintained and frequently upgraded.

7.18.2 Asset description

The majority of our primary asset information is held in our asset database and Geographic Information System (GIS). We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy. In addition to these asset registers we also hold detailed information regarding customer connections in our Connections Register and track the process of asset creation and maintenance in our Works Management system.

Geographic Information System (GIS) – Orion's GIS records our network assets according to their location, type and electrical connectivity. It interfaces with other information systems such as substation asset attribute data stored in our asset register. GeoMedia specialises in reporting and analysing geographic data. In particular, GeoMedia easily combines core GIS and third-party datasets such as aerial imagery for both Orion and service provider and consultant use.

Various GIS viewer technologies enable Orion to deliver 'fit for purpose' geographic asset information within Orion premises, or off site via a secure website. In areas where internet coverage is limited, GIS datasets may be stored directly on a laptop device.

Asset database – EMS Basix, provides a central resource management application that holds details of key asset types with their current location/status. The assets covered include land, substations and all our major equipment including HV cables with less strategic types being added over time. Schedules extracted from this database are used for preventative maintenance contracts and it archives any inspection/test data gathered during the contract.

Works Management – We manage all types of works activity using purpose-built in-house developed applications which populate a single works data repository.

The applications are optimised for different types of work including new connections management, general network jobs and emergency works. When a job is created in Works Management a companion job is also automatically created in the financial system (NAV) to track job related invoices.

Connections Register – Our in-house developed Connections Register holds details of all installation control points (ICP) on our network. This is linked with the industry registry. Links with our GIS systems enable accurate derivation of GXP information by ICP and the association of ICP with an interruption. Interruptions are now routinely traced within the GIS using the in-built connectivity model, and accurate information about the number of customers and interruption duration are recorded.

7.18.3 Asset health

GIS – Our GIS is very mature and approaching the end of its current lifecycle. In addition to problems presented by an aging platform, the highly complex models implemented in the GIS make database maintenance and data updates difficult. Although stable, the GIS is marginal in relation to its capacity and performance for the time frame of this plan.

Asset database – We use the most current available version of EMS Basix. We use only a subset of the capabilities of the EMS Basix database which can be applied to Works Management as well as asset tracking. The performance and capacity of the upgraded system is adequate for the time frame of this plan. Basix will be included in a review of asset management systems associated with Works Management.

Works Management – Works Management is a bespoke job management environment that was originally implemented in the early 2000s. It was subject to a review in FY17 when we found the underlying database to be sound from both an architecture and overall performance perspective. The user facing components of this system however, which are based on aging technology, have in some cases been moved to a new portal called "Toolbelt".

Faced with a business that is responding to a rapidly changing energy sector it is clear that the limitations of this application will need to be addressed and a review is currently underway.

The performance and capacity of the database is adequate for the time frame of this plan but a search for a more complete and integrated asset management solution is under way.

7.18 Information systems continued

Connections Register – Its capacity and performance are adequate for the period of this plan if there are no further major changes required. The Connections Register has been modified significantly since its establishment in FY00, to support a range of new business processes. This system has however reached a "tipping point" and without a change to its underlying architecture, there is a high degree of risk in developing it further.

7.18.4 Maintenance plan

General – All our systems are supported directly by our Information Solutions team with vendor agreements for third tier support where appropriate.

License costs provide a degree of application support but are substantially a prepayment for future upgrades. Although licenses guarantee access to future versions of software they do not pay for the labour associated with their implementation. Our experience has been that significant support is required for the vendor to accomplish an upgrade and these costs are reflected as capital projects in our budgets.

Software releases and patches are applied to systems as necessary and only after testing. Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices

GIS – This is supported directly by the vendor with backup from the Orion Information Solutions team. Support hours are pre-purchased as part of an annual maintenance agreement

Asset database – EMS Basix and related computer infrastructure are supported directly by the Orion Information Solutions team

Other systems – All other systems are supported directly by the Orion Information Solutions team. Some recoveries are made from salaries to capital

An annual forecast of information system operational expenditure is shown in Table 7.18.1.

Table 7.18.1 Information system operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Routine and corrective maintenance and inspections	355	455	455	455	455	455	455	455	455	455	**4,450**
Total	**355**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**4,450**

7.18.5 Replacement plan

The replacement capital expenditure in the Commerce Commission's categories can be found in Table 7.18.2. The capital expenditure for FY23 supports a major overhaul of the model in GIS. The rest of the forecast enables an asset database and project management system upgrade.

Table 7.18.2 Information systems replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Other network assets	550	40	190	40	40	47	50	54	56	56	**1,123**
Total	**550**	**40**	**190**	**40**	**40**	**47**	**50**	**54**	**56**	**56**	**1,123**

Our maintenance plan has been effective in keeping our standby generators in good condition.

7.19 Generators

7.19.1 Summary

We use diesel generators as a mobile source of energy to maintain supply of electricity or provide power to customers in the short term until the network is able to be restored following a fault or during a planned interruption. 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 in good condition. We are not planning to replace any units over the next ten years. We built a shed at the Papanui Zone Substation to house our trucks and mobile generators to reduce deterioration from exposure to the elements. We have replaced a trailer mounted unit with a truck mounted in FY20 and trialed new innovative technologies.

7.19.2 Asset description

We have 14 diesel generators as shown in Table 7.19.1. We have:

- **400V truck-mounted mobile generators** – which are used to restore or maintain supply at a distribution level during a fault or planned work
- **400V building generators** – all have synchronisation gear and can pick up the entire building load. The 110kVA unit is attached to the remote TDC (Transportable Data Centre). A 550kVA unit is attached to our main office building with and the other 550kVA unit is installed at Connetics yard in the Waterloo 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 at Papanui. In addition, we have a new 66kVA which is trailer mounted

Table 7.19.1 Generator types

Voltage	Type	kVA				Total	Avg age
		8 - 30	66 - 110	330 - 440	550		
400V	Mobile		2	2	1	5	11
	Building generators		1		2	3	9
	Emergency standby	2		1	3	6	13
Total						**14**	

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)

7.19 Generators continued

7.19.3 Asset health

There have been no major mechanical issues with the generators. Our generators are in good condition.

Table 7.19.2 Generator conditions by type

Voltage	Type	Condition
400V	**Mobile**	Good condition
	Building generators	Good condition
	Emergency standby	Good condition

7.19.3.1 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 pick up most issues during our routine maintenance.

7.19.4 Maintenance plan

We employ a number of different asset management practices 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 7.19.3.

An annual forecast of generator operational expenditure in the Commerce Commission categories is shown in Table 7.19.4.

Table 7.19.3 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, 8-110 kVA 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

Table 7.19.4 Generator operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Routine and corrective maintenance and inspections	40	40	40	40	40	40	40	40	40	40	**400**
Total	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**400**

7.19.5 Replacement plan

When a generator gets to the end of its economic life, analysis will be done to see if it will be replaced. The 440kVA generator has done more than 8,200 hours and is 15 years old. When it gets to 10,000 hours we will assess whether it is more economic to do major maintenance or replace it with a new unit. We are planning to replace trailer mounted units to truck mounted. The replacement expenditure is covered in Section 8.8 – vehicles. Expenditure has been allocated for controller and AVR replacement from FY23 – FY27.

7.19.5.1 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.

7.19.6 Innovation

To keep the power on for the community during emergency and network maintenance work, Orion has typically used around 150,000 litres of diesel per year in its generators, emitting the equivalent of 400 tonne of CO2.

In FY21 we conducted a proof of concept trial to see if Orion's generators could be powered by biodiesel, a clean-burning diesel replacement made from recycled vegetable oil, produced locally.

The trial using 300 litres of GreenFuels® waste vegetable oil produced locally from fast-food outlets in one of Orion's 440kW generators was successful, generating a steady flow of acceptable power quality.

We are following up with a series of detailed live tests on a range of Orion generators, comparing biofuel with mineral diesel across a range of parameters.

Our focus is on understanding biofuel's reliability and emission reductions, and testing includes upper limit testing, comprehensive emission tests and, eventually, live tests on the network.

We are now refining our processes and conducting further trials to assess the viability of switching from diesel to biofuel on an operational scale.

Most of our generators have been fitted with SCADA which provides alarming and monitoring. Reverse synchronising has been fitted which allows the generator to be returned from an islanded state with connected load, avoiding an outage to the customer.

Our mobile generators have been fitted with equipment to allow the generator to operate in a voltage support mode.

This is where the generator is operated in parallel with the network and as the load drops the voltage increases, allowing the generator to shut down, saving fuel.

We have now fitted control relays that allow the generator to start large loads or areas of islanded network after a fault. This has drastically improved customer service by reducing restoration times.

We have also fitted a Statcom to one truck and are planning on fitting to others. These allow the generators to shutdown at low load while paralleled, reducing engine wear and fuel use.

We have now fitted control relays that allow the generator to start large loads or areas of islanded network after a fault. This has drastically improved customer service by reducing restoration times.

Table 7.19.5 Generator capital expenditure (real) - $,000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Other network assets	20	20	20	20	20	-	-	-	-	-	**100**
Total	**20**	**20**	**20**	**20**	**20**	**-**	**-**	**-**	**-**	**-**	**100**

We have replaced most of our monitoring assets and the majority are in good condition and meet our service level targets.

7.20 Monitoring and Power Quality

7.20.1 Summary

Our monitoring assets are comprised of high voltage (11kV), GXP and power quality metering. We have replaced most of our monitoring assets and the majority are in good condition and meet our service level targets.

7.20.2 Asset description

Our monitoring assets cover three areas in our network:

- **High voltage (11kV) customer metering** – we own the metering current transformers (CTs) and voltage transformers (VTs) along with associated test blocks and wiring at approximately 75 customer sites. Retailers connect their meters to our test block and all Orion metering transformers are certified as required by the Electricity Governance Rules
- **Transpower (GXP) metering** – we own metering at Transpower GXPs. We adopted GXP-based pricing in 1999 and most of our revenue is now derived from measurements by Transpower GXP metering. The data from these meters serves as input into our SCADA system for load management and our measurements are used to estimate readings when Transpower's meters fail
- **Power quality monitoring** – we have installed approximately 30 permanent, standards compliant, power quality measurement instruments across a cross-section, from good to poor, of distribution network sites. Data collected are statistically analysed to monitor the long-term network performance and to assist the development of standards and regulations

Table 7.20.1 Monitoring quantities by type

Asset	Quantity
Current Transformers	45
Voltage Transformers	34
Quality Meters	13
Total	**92**

7.20.3 Asset health

7.20.3.1 Condition

Generally, all metering equipment is in good condition.

7.20.3.2 Performance

Our monitoring assets overall have proven to be robust, are performing well and are meeting all the service level targets. We check our 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 customer complaints. 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 quality of the network to assess the impact of the increasing number of non-linear loads that are connected each year.

7.20.3.3 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.

7.20.4 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 7.20.2 and the associated expenditure in the Commerce Commission's categories is shown in Table 7.20.3. 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.

Table 7.20.2 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

Table 7.20.3 Monitoring operational expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Routine and corrective maintenance and inspections	113	53	16	5	20	16	5	5	5	5	**243**
Total	**113**	**53**	**16**	**5**	**20**	**16**	**5**	**5**	**5**	**5**	**243**

7.20.5 Replacement plan

Table 7.20.4 shows the replacement capex in the Commerce Commission's categories. The expenditure is based on replacing end of life meters and metering equipment as well as faulty ferroresonance capacitor banks over the next 10 years.

Table 7.20.4 Monitoring replacement capital expenditure (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Quality of Supply	75	75	75	75	40	40	40	40	40	40	**540**
Other network assets	60	20	20	20	20	31	37	41	44	43	**336**
Total	**135**	**95**	**95**	**95**	**60**	**71**	**77**	**81**	**84**	**83**	**876**

8

Supporting our business

Photo: Vicky Ross, a member of Orion's Procurement and Land Services Team.

Contents

8.1 Introduction

In this section we describe the work of the teams in Orion that together, enable our business to function. We set out what each team does and our operational and capital expenditure forecast for each team. We also describe the business information systems that support our administrative functions, and the fleet of vehicles we use to do our work and engage with the community.

8.2 Gearing up for the future

Our engagement with customers, as described in Section 4, has helped us understand how we need to prepare for their future needs. Our customers want a safe, reliable, resilient network and one that is built ready for them to take advantage of new technologies. To deliver this, in FY21 we adopted a new Group Strategy with our Purpose to: *Power a cleaner and brighter future for our community.* See Section 2.4.

To help us deliver on our Group Strategy, in FY22 we reshaped our organisational structure, business model and leadership team to provide the focus and capability we need now and into the future.

The Orion Group's integrated leadership team consists of:

- Chief Executive Connetics
- General Manager Future Network
- General Manager Electricity Network
- General Manager Purpose and Performance
- General Manager Value Optimisation
- General Manager Data and Digital
- General Manager Energy Futures
- General Manager Growth and Development

Our leadership structure ensures we concurrently take a strategic and tactical view of our operating environment and customer needs.

Our Group Strategy, new business model and capability evolution positions Orion Group to support a future that calls for us to take a broader approach to the challenges and opportunities presented by the new era in the energy sector. It has created the framework for Orion to build a more sustainable business, explore new opportunities to contribute to our community, and be more agile and responsive to our customers' changing needs.

A world of new energy opportunities is opening up for us and our customers. The changes we have made to our business will enable us to efficiently and cost effectively build Orion Group's contribution to a more connected and interactive future.

Our strategic focus on building long term capability means we have reviewed and reshaped our approach to works delivery with our service provider partners. For the delivery of our planned and unplanned works on overhead, substation and underground assets we have established a Primary Service Delivery Partner (PSDP), Connetics, to plan and procure work from Connetics and a number of other service providers through a dedicated arms-length Project Management Office (PMO). This will ensure we are able to efficiently deliver the initiatives and projects in this AMP.

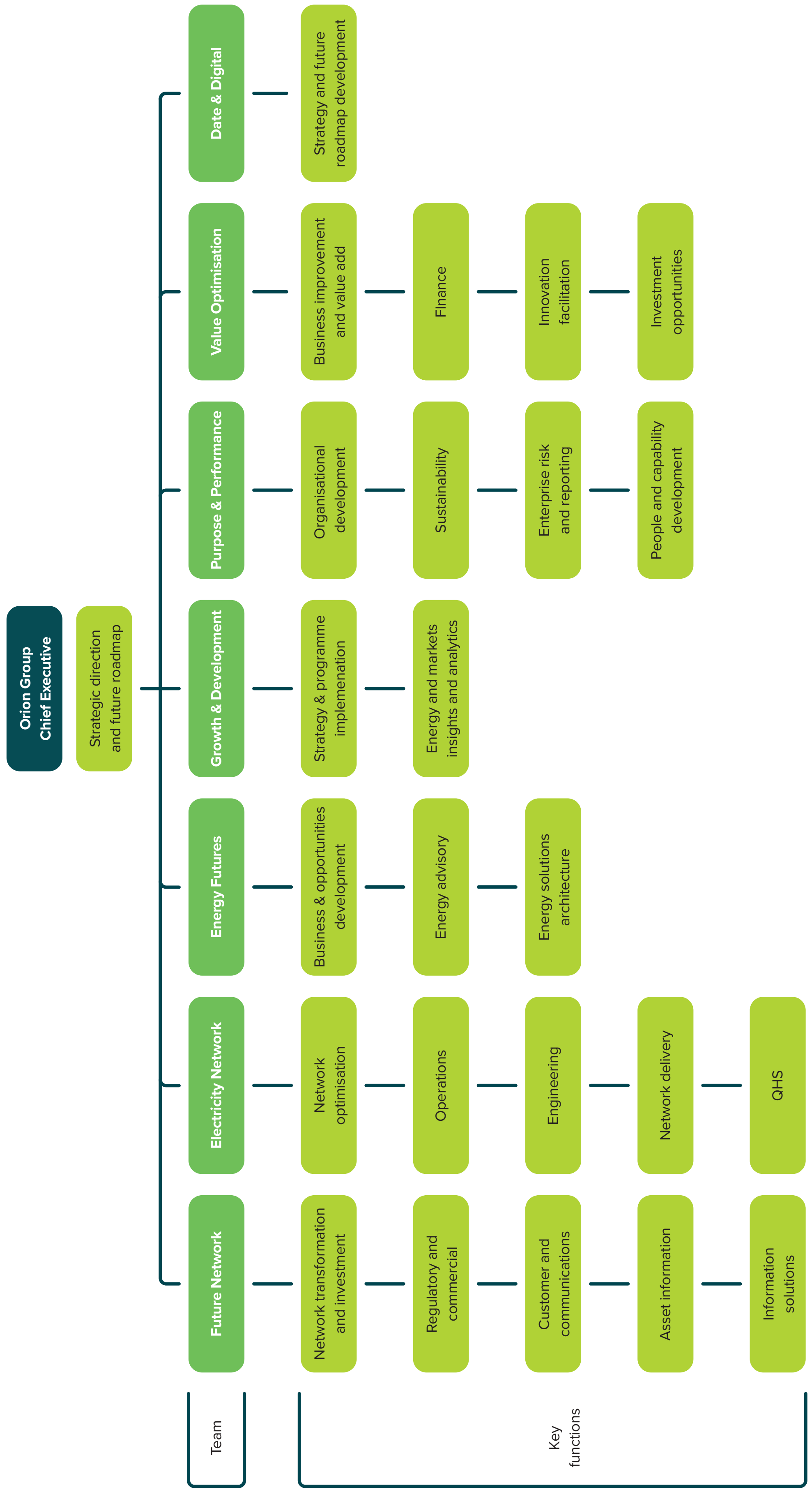
We have heightened our focus on data and digitisation to ensure we have a deeper understanding of how our customers are using our network, and ensure we capitalise on that insight in our business process and system development. Our focus in this area also ensures we have the right information to inform our decision making and develop efficient services for our teams and customers alike.

Our organisational changes and other initiatives to support our community's evolving needs, delivery of the projects in this AMP and our increased focus on preparing for the future will result in a gradual increase in FTEs over the regulatory period.

The Commerce Commission defines two categories for people-related opex: System Operations and Network Support, and Business Support. The balance of this section is split between these two categories. This means that activities under the integrated leadership team may appear in either one or both of the Commission's categories. We will use cost allocation to account for roles and services that are not part of the regulated service.

To help us deliver on our Group Strategy, in FY22 we reshaped our organisational structure, business model and leadership team to provide the focus and capability we need now and into the future.

Figure 8.2.1 Organisation structure



8.3 System operations and network support

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.

8.3.1 Future network

The future network group is responsible for the overall direction and management of our network infrastructure.

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 group 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

Asset information 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 2,000 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, Technical:

- this programme mentors and develops our people as they progress through their focussed training – see 8.4.1

The balance of our Future Network team is in the business support category, see 8.5.

8.3.2 Electricity network

Our electricity network group 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 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

8.3 System operations and network support continued

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 other 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
- 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

Network operations team:

Our network operations team includes our control centre, operations improvement, 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
- 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

8.3 System operations and network support continued

Release planning team:

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

Quality, health and safety (QHS) team:

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

- provides governance over and continuous improvement of the Orion QHS systems
- provides general QHS advice to business and other stakeholders as required
- administers Vault, our safety information management system
- leads the QHS audit program and delivers process assurance
- leads significant investigations
- coaches our Incident Cause Analysis Method (ICAM) investigation team and builds competency
- coordinates QHS training initiatives
- provides QHS assurance to Orion, board and management and the Electricity Engineer's Association
- provides stand-overs for safety on excavations or other work conducted by third parties on Orion's sub-transmission assets

8.3.3 System operations and network support expenditure forecast

The forecast for our operational expenditure for the activities of each of these teams in FY22 dollar terms is shown in Table 8.3.1.

Notes to expenditure:

- our most significant operational expenditure in these teams is remuneration for our employees
- this chart does not include operational expenditure on our network assets
- it also does not include the following, consistent with the operational expend forecasts that are shown in non-network operational expenditure schedule 11b in Appendix F:
  - pass-through costs, such as local authority rates and industry levies
  - depreciation
  - transmission purchases
- for the first time, we have allocated a network innovation investigation budget to explore alternative models of supporting our network and system operations to drive future distribution network models. See Section 7

Table 8.3.1 System operations and network support (real) – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Electricity network	1,152	1,142	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	**11,270**
Future network	4,552	4,550	4,493	4,492	4,567	4,546	4,514	4,489	4,489	4,489	**45,181**
Network operations	6,377	7,131	7,121	7,130	7,139	7,148	7,157	7,176	7,175	7,184	**70,738**
Customer support	724	724	724	724	724	724	724	724	724	724	**7,240**
Engineering	3,632	3,635	3,635	3,640	3,640	3,645	3,645	3,645	3,645	3,645	**36,407**
Works delivery	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	**13,620**
Customer connections	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	**20,880**
Procurement and property services	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	**10,860**
Quality, health and safety	829	829	829	829	829	829	829	829	829	829	**8,290**
Asset storage	840	840	840	840	840	840	840	840	840	840	**8,400**
Less capitalised internal labour	(4,396)	(4,142)	(3,453)	(4,317)	(4,275)	(4,062)	(4,006)	(4,072)	(4,080)	(4,059)	**(40,863)**
Total	**18,246**	**19,245**	**19,847**	**18,996**	**19,122**	**19,329**	**19,361**	**19,289**	**19,280**	**19,310**	**192,023**
Totals from 1 April 2021 AMP	**17,419**	**17,637**	**17,864**	**17,504**	**17,796**	**17,820**	**18,210**	**18,696**	**18,734**	**n/a**	**n/a**

8.4 Future Capability Development

8.4.1 Orion Development Programme, Technical

We apply a structured approach to training future leaders for the industry through a four year programme that develops participants' practical and theoretical understanding of engineering. We generally aim to have 8 participants in the programme at any one time.

Of our current permanent staff, 23 people are graduates of our Development Programme, Technical.

This innovation contributes to delivery of our asset management strategy focus on developing our capability as asset managers, and embracing the opportunities of future networks. Our customers benefit from our sustainable approach to building capability that ensures we remain effective stewards of our assets, now and into the future.

8.4.2 Orion Development Programme, Graduate

In 2020 we initiated the Orion Development Programme, Graduate, and took on a university graduate to complete a two-year placement rotation through various areas of our business.

8.4.3 Energy Academy

As Energy systems globally shift, so will the need to develop new capabilities to adapt and change as we evolve.

Energy Academy is an initiative of the Orion Group with the purpose of galvanising the industry to work on common challenges to harness energy's potential to create a more prosperous, equitable and sustainable New Zealand.

Some of the Energy Academy programmes underway include hosting a future of energy forum, forming an industry collaboration platform that enables organisations from across the sector to work together on challenges and share learnings and piloting a new model that redefines the roles of industry in tertiary training.

8.5 Business support

Around one quarter of our people work in this activity area.

8.5.1 Purpose and Performance

This team leads Orion Group strategy and business plan delivery, enterprise risk management, business reporting, performance including people and capability, and sustainability.

Risk and reporting team:

This team supports, monitors and measures the business in the areas of risk management, business and board reporting and board support.

People and capability team:

This team provides strategic, tactical and operational support, including change management, and advice to the business in the people/HR space, including payroll and wellbeing.

By supporting our leaders and managers to build capability and performance we seek to achieve the best organisational results through our people.

Sustainability team:

The sustainability team focuses on strategic initiatives, industry collaboration and operational reporting in support of powering a low carbon economy.

This team:

- understands our carbon footprint
- measures and reports on our carbon emissions
- reports on the opportunities and risks associated with climate change
- directs our sustainability activity on both our network and in the wider community in support of addressing climate change opportunities and risks
- builds sustainability partnerships in the community

8.5.2 Value Optimisation

This team 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.

Other value optimisation services team:

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

8.5.3 Future Network

Information solutions team:

This team is responsible for leading the business in the selection and delivery, ongoing configuration, integration and management of our information systems. These include standalone applications, data and computing platforms, and all supporting infrastructure.

Our people provide tier one through tier three support for systems, and we augment our services by partnering with vendors and expert third parties. We operate annual maintenance agreements in support of key systems across a range of business functions, including traditional business support, asset management, planning and real time operations.

Until recently on-premise systems have dominated our portfolio, but we are increasingly adopting cloud (SAS) solutions.

Our information solutions team is insourced, and salaries are the largest single component of our operational expenditure. We expect however that a shift to cloud and to subscription-based licensing models will drive an increase in other operating costs.

Information Solutions Team members are divided evenly among support services and infrastructure, system development and business change, and the delivery of the real-time operational systems.

Real-time operational systems are crucial to our future and the most important of these is PowerOn from GE. PowerOn allows our control room and field staff to interact in real time with network assets, significantly improving performance of our network, and building new capability to manage both planned and unplanned outages. It is the platform on which we will automate the restoration of power following a network outage, enabling the network to self-heal. It is also the platform on which we will optimise network performance by partnering with owners of Distributed Energy Resources (DERs).

Regulatory and commercial team:

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

- our engagement with and submissions to the Commerce Commission, Electricity Authority and other industry regulators
- our network delivery pricing approach, compliance reporting and
- 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
- facilitating customer inspired conversations about future power options

8.5.4 Data and digital

The data and digital team has been established to take a strategic view on our enabling data governance and digital system evolution in support of improved decision making, system control, business outcomes and customer centricity.

8.5.5 Growth and development

The growth and development team is responsible for:

- 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
- leading exploration of innovation functions i.e. leveraging existing business models and technologies

8.5.6 Energy Futures

The energy futures team is responsible for exploring future energy markets and business models.

8.5.7 Board

We have a board of six non-executive directors, with extensive governance and commercial experience.

8.5.8 Insurance

We purchase insurance to manage specified financial risks. The fees forecast are shown in Table 8.5.1.

8.5.9 Business support operational expenditure forecast

The forecast expenditure for the activities of each of our business support teams, expenditure on insurance, corporate property and vehicles in FY22 dollar terms can be found in Table 8.5.1.

Table 8.5.1 Business support operational expenditure – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Future network	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	**14,750**
People and capability	1,348	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	**11,446**
Integrated leadership team	5,492	7,081	7,067	7,156	7,061	7,061	7,061	7,061	7,061	7,061	**69,162**
Finance	1,715	1,676	1,675	1,705	1,675	1,665	1,723	1,665	1,675	1,705	**16,879**
Information solutions	4,650	4,993	4,906	4,895	4,916	4,895	4,896	4,915	4,896	4,895	**48,857**
Regulatory and commercial	1,962	2,091	3,345	1,819	1,824	1,828	1,892	1,897	1,841	1,846	**20,345**
Customer and communications	2,038	2,788	2,788	2,788	2,788	2,788	2,788	2,788	2,788	2,788	**27,130**
Insurance	2,879	3,269	3,713	4,219	4,795	5,452	6,200	7,053	8,025	9,132	**54,737**
Corporate property	1,033	1,033	1,036	1,009	1,015	1,018	1,018	1,019	1,017	1,016	**10,214**
Vehicles	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	**(11,380)**
Less capitalised internal labour	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	**(12,000)**
Total	**20,254**	**23,190**	**24,789**	**23,850**	**24,333**	**24,966**	**25,837**	**26,657**	**27,562**	**28,702**	**250,140**
Totals from 1 April 2021 AMP	**19,097**	**19,151**	**19,161**	**19,263**	**19,396**	**19,472**	**19,571**	**19,741**	**19,798**	**n/a**	**n/a**

Notes to Table 8.5.1:

- The Property expenditure shown here is before any depreciation expense is recognised as depreciation does not form part of business support operational expenditure.
- The vehicle fleet surplus shown above excludes depreciation expense and insurance.

Table 8.5.2 Board of directors' fees and expenses

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Board of directors' fees and expenses	451	446	446	446	446	446	446	446	446	446	**4,465**
Total	**451**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**4,465**
Totals from 1 April 2021 AMP	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**n/a**	**n/a**

8.5.10 Business support capital expenditure forecast

Our capital expenditure forecasts for non-network assets are detailed in Appendix F, Schedule 11a. Specific comments about the composition and management of our most significant non-network assets, buildings, corporate information systems and vehicles, follow in Sections 8.6 to 8.8.

8.6 Corporate properties

8.6.1 Asset description

Our corporate property portfolio covers our administration building at 565 Wairakei Road, Connetics' Waterloo base and rental properties throughout the Canterbury region. Our corporate properties vary in both construction and age.

- **Administration building** – our Wairakei Rd administration building was built in FY14.
- **Connetics' Waterloo base** – Connetics moved to a new, purpose-built facility in Waterloo Business Park in FY18 to provide a more operationally efficient and resilient base for its operations. Orion owns the depot with Connetics entering a long-term 'arms-length' lease.
- **Rental properties** – we own nine rental properties four of which are residential properties adjacent to zone substations. Some of these were acquired as part of a package when substation land was purchased. Others have been strategically purchased to allow the substation to expand if necessary. We receive income from these properties, provided they are tenanted, and this rental income is in line with the rental market in the Christchurch area.

We are a lifelines utility under the Civil Defence Emergency Management Act 2002, providing essential services to the community. This means we are required to be operational after a significant event. Our administration building was built to Importance Level 4 (IL4). This means that the building is designed to remain operational following a 1 in 500 year seismic event. The building is also equipped with a standby generator, with 500 litre diesel tank, which is able to provide back-up power.

As part of our Pandemic Response Plan, and to support protocols we put in place during COVID-19 we established a permanent emergency operational centre for our Controllers and Customer Support team at our Papanui Zone Substation.

We are a lifelines utility under the Civil Defence Emergency Management Act 2002, providing essential services to the community.

Our property assets must meet the following criteria:

- they must be fit for purpose and maintained in a reasonable condition so the occupier can fully utilise the premises
- they shall comply with all building, health and safety standards that may apply
- they must be visually acceptable

8.6.2 Maintenance plan

We have no assigned 'end of life' for our corporate properties. Our property asset management programme ensures our corporate property is managed in a manner that is consistent with Orion's corporate obligations to deliver an effective and efficient service.

We carry out regular inspections of our buildings to ensure they remain in good condition and any need for maintenance is identified. Several databases are used to assist us with the management process such as our asset register and our works management system. The risks that our corporate buildings are exposed to are listed below, in no particular order of importance:

- seismic damage
- liquefaction and subsidence
- defective drainage and guttering
- roof leaks
- vegetation/tree roots
- vandalism – repairs carried out as soon as reported
- rust and rot
- extreme weather conditions
- fire
- graffiti

Minor repairs are undertaken as they are identified in the inspection process. Major repair and maintenance work is scheduled, budgeted for and undertaken on an annual basis. Vandalism and graffiti is fixed as soon as we are notified. We have maintenance contracts in place with several service providers to ensure that all aspects of our property and land maintenance are covered.

8.6.3 Replacement plan

We have no replacement plan for our corporate properties. These assets are maintained to ensure they provide the required levels of performance.

8.7 Information systems

8.7.1 Network information systems

Orion has a complex range of sophisticated information systems that together support the operation of our network. Here we outline what those systems do and how they interact with each other.

8.7.1.1 Geographic asset information system

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. Information stored in our GIS includes:

- land-base
- aerial photography
- detailed plant locations for both cable and overhead systems
- a model of our electricity network from the Transpower GXPs to the customer connection
- conductor size and age

Our asset information team updates and maintains the GIS data. Data integrity checks between our asset register and the GIS are automatically run every week. Systems are in place to facilitate and manage GIS business development in-house.

8.7.1.2 Asset database

Our asset database is our central repository for details of the non-spatial network assets. Schedules extracted from this database are used for preventative maintenance contracts and network valuation purposes.

Information we hold includes:

- substation land (title/tenure etc.)
- transformers
- switchgear and ancillary equipment
- test/inspection results for site earths, poles and underground distribution assets
- transformer maximum demand readings
- cables and pilot/communication cable lengths, joint and termination details. This is linked to our GIS by a unique cable reference number
- protection relays
- substation inspection/maintenance rounds
- poles and attached circuits
- valuation schedule codes and modern equivalent asset (MEA) class
- field SCADA and communication system
- links to documentation and photographs

See table in Appendix C for more specific detail of information held on each asset group.

8.7.1.3 Works Management system

All works activities are managed using an in-house application. There is integration with our financial management system that allows works orders to be raised directly in Works Management.

Information held in Works Management includes:

- service provider/tendering details
- contract specifications and drawings
- management of customer connection requests
- auditing outcomes
- contract management documentation
- financial tracking
- job as-built documentation

8.7.1.4 Document management

We manage most of our key documents in Microsoft SharePoint.

Our engineering drawings and standard documents are controlled using a custom-built system. This system is used to process the release of CAD drawings to outsourced service providers and return them as “as-built” drawings at the completion of works contracts. Standards and policies maintained in-house are also controlled using this system. Standard drawings and documents are then posted directly on our ‘restricted’ website and the relevant service providers/designers are advised via an automated email process.

8.7.1.5 Connections Register

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 PowerOn 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 external website.

8.7.1.6 Financial Management Information System (FMIS)

Our FMIS (Microsoft NAV) 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.

There is an interface between the Works Management system and the financial system to link project activities to jobs.

8.7.1.7 Cyber security management

We have a number of protection systems and processes in place to address the growing threat of cyber security breaches. See Section 3.7.4.

8.7.1.8 Advanced Distribution Management System (ADMS)

We operate an integrated ADMS (PowerOn from GE) that includes the following modules:

Network monitoring system (SCADA)
The 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. We are also progressively installing SCADA at network substations throughout the urban area as old switchgear is replaced.

Network Management System (NMS)
The NMS is a real-time software model of our high voltage distribution network that sits above the SCADA system. It allows interaction in real time with indication and control devices to provide better information on network configuration. This gives us the ability to decide on how to respond to network outages, especially big events such as storms, and manage planned maintenance outages to minimise the impact on customers. The system also allows us to automate some functions and improve response times in network emergencies.

Outage Management System (OMS)
The OMS is the third component (along with the SCADA and NMS functions) of a comprehensive "Smart" Distribution Management System that drives much of our operational activity. Outages are inferred from SCADA 'trippings' or from customer call patterns and are tracked through their lifecycle. Key performance statistics are automatically calculated and an audit trail of HV switching activity is logged. Integrated into the NMS and OMS is a mobile extension which delivers switching instructions to field operators in real time and returns the actions they have taken. It also delivers fault jobs to field workers and tracks the progress of the job as it is worked on. Jobs requiring further work by an emergency service provider are automatically dispatched to the service providers' administration centre. Service providers enter completion information directly into a web-based application, and the job details automatically flow through into the works database.

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. Safety documents related to the operating order are also provided directly to the hand-held device. A recent enhancement to this application will also check that an operator has the appropriate certifications for operating the equipment associated with the order before allowing them to proceed.

Distribution Power Flow Analysis (DPF)
DPF is a decision support tool for our Network Controllers. It can perform network power analysis studies that compute electrical network statuses and provide power analysis data to Controllers. DPF studies can run as simulations and include switching schedules and switching work/order and patches.

Service Request Register (SRR)
SRR is a service provider online switching release request system. The online release request system manages requests from multiple service providers who wish to undertake planned work on network equipment. This replaces a largely manual, paper-based system for planned outages.

8.7.1.9 Load Management

A high-availability Load Management system is used to perform load shedding to reduce the magnitude of our peak load and to respond to Transpower constraints. We also run an "umbrella" Load Management system that co-ordinates the load management systems of each of the seven 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.

8.7.1.10 Network analytics

A database of well over 100 million half-hour loading values 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.

8.7.1.11 Data warehouse and BI

A data warehouse that hosts data from financial, asset management and control systems is in place to meet increasing demand for more sophisticated business reporting, analytics and dashboards. Microsoft's Power BI is deployed throughout the business.

8.7.1.12 Interruption statistics

We automatically post outage information from the PowerOn 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.

8.7.1.13 Demolition tracking

Demolition jobs are dispatched to the field and demolition details returned electronically.

8.7.1.14 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. For more information on CBRM see Section 5.6.2.1.

8.7.1.15 Health and Safety event management

Incidents are recorded, managed and reported in our safety management system. 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.

8.7.1.16 Delivery billing system

We have contracted NZX Energy, a leading data services and market place support company, to provide our delivery billing system. The system receives connection and loading information, calculates delivery charges and produces our monthly invoices to electricity retailers and directly contracted major customers.

8.7.1.17 Power system modelling software

An integral part of planning for existing and future power system alterations is the ability to analyse and simulate impact off-line using computer power-flow simulation.

We use a power-flow simulation software package called PSS/Sincal and can model our network from the Transpower connection points down to the customer LV terminals if required. An automated interface developed in-house is used to enable 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.

8.7.1.18 Orion website

Our website is logically divided into two distinct areas. One focuses on the delivery of information to our customers and the other on interactions with third parties.

The customer facing portion of the web site provides the following information:

- Customer outage reporting - details of planned, current and past outages on our web site are populated automatically by extracts from the PowerOn Outage Management System. This provides accurate real-time reporting of customer numbers affected by an outage. Outages can be viewed as a list or on a map.
- Load management - we provide near real-time network loadings, peak pricing periods and hot water control
- Electricity pricing
- Company publications, regulatory disclosures and media releases
- Public safety and tree trimming information

The interactive section of our website is a services portal that manages third party access to a range of services.

Services include:

- connections-related service requests for new and modified network connections.
- annual work plan
- standard drawings, design standards, operating standards, specifications
- network location map requests
- close approach consents
- new and modified connection requests
- livening requests for action by livening agents

We are embarking on the delivery of a Customer Relationship Management (CRM) system that will become a cornerstone for the digitisation of business processes and a key platform to manage and deliver services to our customers.

8.7.2 Asset data integrity

Most of our primary asset information is held in our asset database, GIS system and cable database. We hold information about our network equipment from GXP connections down to individual LV poles with a high level of accuracy. The data has become more complete and more accurate over time.

Due to improved asset management plans, regulatory compliance and better risk identification and management, asset information accuracy has improved. This has ensured that we can locate, identify and confirm ownership of assets through our records.

Although there will inevitably be some minor errors and improved information will always be required, we believe our information for most of the network is accurate. Some information for older assets installed more than 25 years ago has been estimated based on best available data. Examples of this include:

- the conductor age for some lines older than circa 1990
- timber poles that went into service prior to the use of identification discs
- older 11kV air break switches and cut-out fuses

8.7.3 Customer Relationship Management

We are embarking on the delivery of a Customer Relationship Management (CRM) system that will become a cornerstone for the digitisation of business processes and a key platform to manage and deliver services to our customers. The CRM will be built around Microsoft's Dynamics platform and will incorporate several functions currently managed through other systems. It will establish a "single source of truth" for customer related information and allow real time interactions with other business systems.

The CRM will initially model a number of simpler customer journeys and build to a more sophisticated solution over the next four years.

8.7.4 Low Voltage Data Model

As part of a wider strategic initiative associated with the future operation of our low voltage network we are developing a model for the collection, storage and consumption of data on the status and performance of LV assets. A prototype is currently under development.

8.7.5 Corporate information systems

Our corporate business information systems and productivity software support processes that run across Orion. They include financial systems, employee management systems, for example human resources, payroll, health and safety and personal productivity software such as desktop applications, email, web and document management.

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 the electricity network.

We deliver services using a combination of on-premise and Software-as-a-Service as appropriate. Increasingly key functions are delivered through cloud-based models and as a consequence, subscription based services are rapidly replacing software managed in house. Windows 365 for instance, is increasingly important for our standard applications, document management and sharing, remote working, and our productivity software (eg messaging and calendaring).

The infrastructure supporting our information systems includes:

- **HR/payroll** – as a cloud based application the performance and availability of this system is subject to a service level agreement.
- **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. It will be integrated with document management as part of the current implementation.
- **Desktop/laptop clients and operating systems** – our choice of operating system and desktop software capacity/performance are adequate for the period 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.
- **Replicated computer room** – we operate two Transportable Data Centres linked by diverse fibre networks which are both performing to expectations.
- **VM and SAN** – our VMware Virtual Server and Storage Area Network infrastructure is managed through a life cycle and regularly upgraded before performance issues arise or warranties expire. Capacity and performance are adequate for the period of this plan.
- **Physical servers** – we still occasionally use individual physical service for specific applications. As with all our infrastructure we manage these servers through a lifecycle. The health of these servers are monitored and we typically replace servers of this type in three to five years.
- **Desktops, laptops, tablets** – we typically upgrade our desktops and laptops on a three-yearly cycle. We expect that the capacity and performance of this equipment will not be adequate for the period of this plan.

8.7.5.1 Maintenance plan

All corporate systems are supported directly by our Information Solutions group with vendor agreements for third tier support where appropriate.

We employ a strict change management regime and software releases, and patches are applied to systems as necessary and only after testing.

Production systems are subject to business continuity standards which include:

- an environment that includes development, test and production versions
- mirroring of systems between two facilities to safeguard against loss of a single system or a complete facility
- archiving to tapes which are stored off site at a third party
- change management processes
- least privilege security practices

8.7.5.2 Replacement plan

We employ a rigorous change management approach to all software and hardware systems. Major changes to all corporate business information systems will follow a project proposal, business case approval, business requirements.

Where appropriate project costs are capitalised, including around $1.2m of labour per annum.

8.8 Vehicles

8.8.1 Asset description

We own 102 vehicles to enable us to operate and maintain the electricity network, engage with the community and respond to any events. Our goal is to ensure we have the right vehicle in the right place at the right time with an appropriately trained driver. Around 41% 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.

8.8.2 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.

Around 41% of our passenger fleet has electric drive capability.

8.8.3 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 we will seek out electric vehicle options.

8.8.3.1 Creation/ acquisition plan

The aim is to have the right vehicle and driver to 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

8.8.3.2 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.

Table 8.8.1 Vehicle quantities and type

Description	Quantity	Lifecycle
Generator truck	4	20 years
Network operator utility	22	5 years or 200,000 km
Electric Vehicle (EV)	10	6 years
Plug-in Hybrid EV (PHEV)	22	6 years
Other	45	4 years on average (earlier for high km's)
Total	**103**	

9 Financial forecasting

$375m
Network operating expenditure

$447m
Non-network operating expenditure

$1,087m
Capital expenditure

Photo: Shot from Plantation Road, Hororata during a nor'wester at sunset; photo taken by Orion Network Operator, Martin Van Beyere.

Contents

9.1 Network expenditure forecasts

Our forecasts are based on our network opex and capex programmes and projects as detailed in Sections 6 and 7. These forecasts are based on the best information available at the time of publishing.

9.1.1 Opex – network

Table 9.1.1 Opex network – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtransmission overhead lines	1,810	1,680	1,775	2,015	2,335	2,280	2,330	2,315	2,265	2,265	**21,070**
11kV overhead lines	7,721	8,867	9,425	17,905	17,313	17,375	18,464	18,748	19,365	17,865	**153,048**
400V overhead lines	5,350	4,150	4,150	5,050	6,150	6,150	4,950	4,950	4,950	6,150	**52,000**
Storms	245	245	245	245	245	245	245	245	245	245	**2,450**
Earths	325	300	275	295	335	325	300	275	295	295	**3,020**
Subtransmission underground	348	348	348	348	348	148	148	148	148	148	**2,480**
11kV underground cables	2,100	2,100	2,100	2,150	2,150	2,150	2,150	2,150	2,150	2,150	**21,350**
400V underground cables	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	2,895	**28,950**
Communication cables	120	120	120	120	120	120	120	120	120	120	**1,200**
Asset information / management	355	455	455	455	455	455	455	455	455	455	**4,450**
Monitoring and PQ	113	53	16	5	20	16	5	5	5	5	**243**
Protection	902	882	882	922	902	902	902	922	902	902	**9,020**
Communication systems	511	491	401	401	401	401	401	401	401	401	**4,210**
Control systems	546	621	621	621	621	621	621	621	621	621	**6,135**
Load management	404	404	404	404	404	404	404	404	404	404	**4,040**
Switchgear	1,791	1,731	1,701	1,721	1,731	1,808	1,793	1,868	1,833	1,783	**17,760**
Transformers	1,542	1,273	947	1,293	1,283	1,283	1,283	967	957	957	**11,785**
Substations	687	678	678	696	687	687	687	696	687	687	**6,870**
Generators	40	40	40	40	40	40	40	40	40	40	**400**
Buildings and enclosures	1,315	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	**12,250**
Grounds	505	515	515	515	515	515	515	515	515	515	**5,140**
Project management resource (PMO)	750	750	750	750	750	750	750	750	750	750	**7,500**
Total	**30,375**	**29,813**	**29,958**	**40,061**	**40,915**	**40,785**	**40,673**	**40,705**	**41,218**	**40,868**	375,371
Totals from 1 April 2021 AMP	**27,675**	**274,425**	**26,920**	**26,685**	**27,080**	**27,035**	**27,095**	**27,030**	**27,000**	**n/a**	**n/a**

9.1 Network expenditure forecasts continued

9.1.2 Opex – Network (Commerce Commission's categories)

Table 9.1.2 Opex – network (Commerce Commission's categories) – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
System interruptions and emergencies	7,493	7,497	7,496	7,447	7,444	7,445	7,445	7,445	7,443	7,445	**74,600**
Vegetation Management	5,024	5,129	5,231	9,376	9,372	9,372	9,373	9,373	9,371	9,372	**80,993**
Routine and corrective maintenance & inspection	15,457	15,191	15,193	20,415	20,701	20,843	20,887	20,019	20,803	20,449	**190,958**
Asset replacement & renewal	2,401	1,996	2,038	2,823	3,397	3,124	2,968	2,868	3,602	3,602	**28,819**
Total	**30,375**	**29,813**	**29,958**	**40,061**	**40,914**	**40,784**	**40,673**	**40,705**	**41,219**	**40,868**	**375,371**
Totals from 1 April 2021 AMP	**27,675**	**27,425**	**26,920**	**26,685**	**27,080**	**27,035**	**27,095**	**27,030**	**27,000**	**n/a**	**n/a**

9.1.3 Opex contributions revenue

Table 9.1.3 Opex contributions revenue – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
USI load management	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	**(700)**
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	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(1,070)**	**(10,700)**
Totals from 1 April 2021 AMP	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**(1,100)**	**n/a**	**n/a**

9.1.4 Capex summary

Table 9.1.4 Capex summary – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Customer connections/ network extensions	18,608	15,926	15,926	15,926	14,572	16,361	17,331	18,606	18,926	18,918	**171,101**
Asset relocations	7,122	7,342	1,710	1,435	1,435	2,228	2,060	2,273	2,326	2,295	**30,226**
HV minor projects	4,500	4,500	4,500	5,500	5,500	6,388	6,869	7,502	7,661	7,657	**60,576**
LV projects	1,928	2,267	2,702	3,300	3,248	3,101	3,257	3,388	2,511	2,507	**28,208**
HV major projects	24,026	27,408	17,922	25,828	21,835	18,004	15,454	12,484	14,739	13,363	**191,062**
Replacement	43,732	36,688	35,717	46,130	50,576	46,227	46,084	48,293	46,565	47,519	**447,531**
Project management resource (PMO)	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	**17,500**
Capitalised internal labour	4,396	4,142	3,453	4,317	4,275	4,062	4,006	4,072	4,080	4,059	**40,863**
Total	**106,062**	**100,023**	**83,680**	**104,186**	**103,191**	**98,121**	**96,811**	**98,367**	**98,557**	**98,068**	**987,068**
Totals from 1 April 2021 AMP	**83,950**	**77,773**	**71,952**	**77,779**	**72,768**	**71,917**	**62,145**	**50,460**	**49,776**	**n/a**	**n/a**

9.1 Network expenditure forecasts continued

9.1.5 Capital contributions revenue

Table 9.1.5 Capital contributions revenue – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Customer connections/ network extensions	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	(1,238)	**(12,380)**
Asset relocations	(5,087)	(5,263)	(1,055)	(917)	(917)	(1,264)	(1,000)	(1,000)	(1,000)	(976)	**(18,479)**
HV major projects	(1,736)	(3,560)	(972)	-	-	-	-	-	-	-	**(6,268)**
Total	**(8,061)**	**(10,061)**	**(3,265)**	**(2,155)**	**(2,155)**	**(2,502)**	**(2,238)**	**(2,238)**	**(2,238)**	**(2,214)**	**(37,127)**
Totals from 1 April 2021 AMP	**(5,533)**	**(5,633)**	**(1,795)**	**(1,670)**	**(1,670)**	**(1,985)**	**(1,745)**	**(1,745)**	**(1,745)**	**n/a**	**n/a**

9.1.6 Capex – Customer connections / network extension

Table 9.1.6 Capex – Customer connections / network extension – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
General connections	9,330	7,956	7,956	7,956	7,273	8,167	8,651	9,288	9,448	9,444	**85,469**
Large connections	1,700	1,436	1,436	1,436	1,321	1,483	1,571	1,686	1,715	1,715	**15,500**
Subdivisions	3,999	3,406	3,406	3,406	3,111	3,494	3,701	3,973	4,042	4,040	**36,578**
Switchgear purchases	673	649	649	649	596	668	707	759	771	771	**6,892**
Transformer purchases	2,906	2,479	2,479	2,479	2,271	2,550	2,701	2,900	2,949	2,948	**26,662**
Total	**18,608**	**15,926**	**15,926**	**15,926**	**14,572**	**16,361**	**17,331**	**18,606**	**18,926**	**18,918**	**171,101**
Totals from 1 April 2021 AMP	**9,553**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**9,257**	**n/a**	**n/a**

9.1.7 Asset relocations / conversions

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. We negotiate with the third parties to share costs and agree on timeframes. Our forecast for asset relocations / conversions are shown in Table 9.1.7

Table 9.1.7 Asset relocation / conversion capex – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
FY23 AMP	7,122	7,342	1,710	1,435	1,435	2,228	2,060	2,273	2,326	2,295	**30,226**
Contributions	(5,087)	(5,263)	(1,055)	(917)	(917)	(1,264)	(1,000)	(1,000)	(1,000)	(976)	**(18,479)**
Total	**2,035**	**2,079**	**655**	**518**	**518**	**964**	**1,060**	**1,273**	**1,326**	**1,319**	**11,747**
Totals from 1 April 2021 AMP	**1,839**	**1,879**	**585**	**460**	**460**	**595**	**535**	**535**	**535**	**n/a**	**n/a**

9.1 Network expenditure forecasts continued

9.1.8 Capex – replacement

Table 9.1.8 Capex – replacement – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtransmission overhead	1,260	990	90	1,080	3,745	1,468	4,782	1,680	1,746	1,729	**18,570**
11kV overhead lines	9,047	11,087	11,597	13,127	15,637	18,960	18,962	19,356	20,106	19,916	**157,795**
400V overhead lines	750	570	570	570	525	619	670	607	631	625	**6,137**
Subtransmission underground cables	50	50	50	50	50	50	50	50	50	50	**500**
11kV underground cables	250	50	50	100	100	1,200	1,200	1,200	1,200	1,200	**6,550**
400V underground cables	10,645	7,270	7,270	7,320	4,877	1,970	2,240	2,442	2,587	2,549	**49,170**
Communication cables	60	60	60	60	60	60	60	60	60	60	**600**
Monitoring	135	95	95	95	60	71	77	81	84	83	**876**
Protection	3,475	2,007	500	2,336	1,804	863	990	2,737	980	2,633	**18,325**
Communication systems	1,183	1,195	1,045	495	495	435	471	498	519	512	**6,848**
Control systems	1,618	980	1,280	1,880	1,830	203	128	310	28	-	**8,257**
Asset management systems	550	40	190	40	40	47	50	54	56	56	**1,123**
Load management	1,210	1,220	530	960	1,020	271	294	310	224	222	**6,261**
Switchgear	9,792	7,553	8,991	14,132	15,368	13,274	11,877	14,434	13,647	13,282	**122,350**
Transformers	2,132	2,466	2,346	2,868	3,948	5,737	3,151	3,331	3,460	3,427	**32,866**
Substations	755	660	658	622	622	557	603	637	662	655	**6,431**
Generators	20	20	20	20	20	-	-	-	-	-	**100**
Buildings and enclosures	530	225	225	225	225	265	287	304	315	312	**2,913**
Grounds	270	150	150	150	150	177	192	202	210	208	**1,859**
Total	**43,732**	**36,688**	**35,717**	**46,130**	**50,576**	**46,227**	**46,084**	**48,293**	**46,565**	**47,519**	**447,531**
Totals from 1 April 2021 AMP	**36,381**	**35,441**	**34,951**	**37,569**	**43,298**	**35,873**	**33,051**	**28,482**	**27,885**	**n/a**	**n/a**

9.1.9 Capex – replacement (Commerce Commission's categories)

Table 9.1.9 Capex – replacement (Commerce Commission's categories) – $000

Category	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Subtransmission	1,340	1,070	170	1,130	3,795	1,518	4,832	1,730	1,796	1,779	**19,160**
Zone Substation	7,507	3,039	2,511	8,398	10,159	6,306	2,138	5,762	2,937	4,003	**52,760**
Distribution & LV Lines	6,196	8,136	8,646	10,176	12,641	16,283	16,336	16,667	17,441	17,245	**129,767**
Distribution & LV Cables	770	570	570	670	670	3,170	3,440	3,642	3,787	3,749	**21,038**
Distribution substations & transformers	2,599	2,953	2,833	3,355	2,955	3,763	3,619	3,833	3,987	3,947	**33,844**
Distribution Switchgear	7,272	7,846	8,315	9,435	9,848	10,950	11,403	12,099	12,364	12,584	**102,116**
Other network assets	4,682	3,163	2,761	3,055	3,075	1,237	1,316	1,560	1,253	1,212	**23,314**
Quality of Supply	285	285	285	285	250	124	124	124	124	124	**2,010**
Other reliability safety and environment	13,081	9,626	9,626	9,626	7,183	2,876	2,876	2,876	2,876	2,876	**63,522**
Total	**43,732**	**36,688**	**35,717**	**46,130**	**50,576**	**46,227**	**46,084**	**48,293**	**46,565**	**47,519**	**447,531**
Totals from 1 April 2021 AMP	**36,381**	**35,441**	**34,951**	**37,569**	**43,298**	**35,873**	**33,051**	**28,482**	**27,885**	**n/a**	**n/a**

9.2 Non-network expenditure forecasts

9.2.1 Opex non-network

This section describes our forecast opex to plan, operate and administer our network operations. It does not include opex on our network assets, consistent with the Commission's required expenditure breakdowns and definitions.

Table 9.2.1 System operations and network support – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Infrastructure management	1,152	1,142	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	**11,270**
Network management	4,552	4,550	4,493	4,492	4,567	4,546	4,514	4,489	4,489	4,489	**45,181**
Network operations	6,377	7,131	7,121	7,130	7,139	7,148	7,157	7,176	7,175	7,184	**70,738**
Customer Support	724	724	724	724	724	724	724	724	724	724	**7,240**
Engineering	3,632	3,635	3,635	3,640	3,640	3,645	3,645	3,645	3,645	3,645	**36,407**
Works delivery	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	1,362	**13,620**
Customer connections	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	2,088	**20,880**
Procurement and property services	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	1,086	**10,860**
Quality, health, safety and environment	829	829	829	829	829	829	829	829	829	829	**8,290**
Asset storage	840	840	840	840	840	840	840	840	840	840	**8,400**
Less capitalised internal labour	(4,396)	(4,142)	(3,453)	(4,317)	(4,275)	(4,062)	(4,006)	(4,072)	(4,080)	(4,059)	**(40,863)**
Total	**18,246**	**19,245**	**19,847**	**18,996**	**19,122**	**19,329**	**19,361**	**19,289**	**19,280**	**19,310**	**192,023**
Totals from 1 April 2021 AMP	**17,419**	**17,637**	**17,864**	**17,504**	**17,796**	**17,820**	**18,210**	**18,696**	**18,734**	**n/a**	**n/a**

9.2.2 Board of directors' fees and expenses

Table 9.2.2 Board of directors' fees and expenses – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Board of directors' fees and expenses	451	446	446	446	446	446	446	446	446	446	**4,465**
Total	**451**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**4,465**
Totals from 1 April 2021 AMP	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**446**	**n/a**	**n/a**

9.2 Network expenditure forecasts continued

9.2.3 Business support

Table 9.2.3 Business support – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Future network	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	1,475	**14,750**
People and capability	1,348	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	**11,446**
Leadership	5,492	7,081	7,067	7,156	7,061	7,061	7,061	7,061	7,061	7,061	**69,162**
Finance	1,715	1,676	1,675	1,705	1,675	1,665	1,723	1,665	1,675	1,705	**16,879**
Information solutions	4,650	4,993	4,906	4,895	4,916	4,895	4,896	4,915	4,896	4,895	**48,857**
Commercial	1,962	2,091	3,345	1,819	1,824	1,828	1,892	1,897	1,841	1,846	**20,345**
Customer and stakeholder	2,038	2,788	2,788	2,788	2,788	2,788	2,788	2,788	2,788	2,788	**27,130**
Insurance	2,879	3,269	3,713	4,219	4,795	5,452	6,200	7,053	8,025	9,132	**54,737**
Corporate property	1,033	1,033	1,036	1,009	1,015	1,018	1,018	1,019	1,017	1,016	**10,214**
Vehicles	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	(1,138)	**(11,380)**
Less capitalised internal labour	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)	**(12,000)**
Total	**20,254**	**23,190**	**24,789**	**23,850**	**24,333**	**24,966**	**25,837**	**26,657**	**27,562**	**28,702**	**250,140**
Totals from 1 April 2021 AMP	**19,097**	**19,151**	**19,161**	**19,263**	**19,396**	**19,472**	**19,571**	**19,741**	**19,798**	**n/a**	**n/a**

9.2.4 Capex non-network

Table 9.2.4 Capex non-network – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Plant and vehicles	1,365	859	971	1,059	834	1,546	695	679	1,056	1,056	**10,120**
Information technology	7,557	10,133	8,130	9,156	8,785	6,323	4,830	4,325	4,574	4,666	**68,479**
Corporate properties	290	291	707	408	794	295	296	297	298	298	**3,974**
Tools and equipment	1,162	478	883	423	460	423	423	423	423	423	**5,521**
Capitalised internal labour	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	**12,000**
Total	**11,574**	**12,961**	**11,891**	**12,246**	**12,073**	**9,787**	**7,444**	**6,924**	**7,551**	**7,643**	**100,094**
Totals from 1 April 2021 AMP	**7,127**	**4,330**	**4,772**	**4,910**	**4,296**	**5,312**	**3,955**	**3,745**	**4,136**	**n/a**	**n/a**

9.3 Total capital and operations expenditure

Table 9.3.1 Total capital and operations expenditure – $000

	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Total
Capital expenditure	117,636	112,984	95,571	116,432	115,264	107,908	104,255	105,291	106,108	105,712	**1,087,161**
Operational expenditure	69,326	72,694	75,040	83,353	84,816	85,525	86,317	87,097	88,506	89,326	**822,000**
Total	**186,962**	**185,678**	**170,611**	**199,785**	**200,080**	**193,433**	**190,572**	**192,388**	**194,614**	**195,038**	**1,909,161**
Totals from 1 April 2021 AMP	**155,714**	**146,762**	**141,115**	**146,487**	**141,782**	**142,002**	**131,422**	**120,117**	**119,890**	**n/a**	**n/a**

9.4 Changes from our previous forecasts

The fluid nature of our operating environment is reflected in the significant changes to this year's 10 year forecast. A large proportion of these changes are driven by the pressure points of labour and material costs and overall availability. Another major change is the forecast increase in customer driven works predicted in the second half of the programme. This can be attributed to carbon fuel based industrial process heat converting to electrified alternatives and ensuring our network adapts as a service platform to facilitate technology driven customer choice. The total increase of $270m capex and $85m opex, in the 9 year overlap with the last AMP, across the categories has meant that the internal support and project management against works has increased the budget by $26m capex and $7m opex. Details of changes to specific expenditure categories are provided below.

9.4.1 Opex – network

An increase of $25m network operational expenditure due to better scoping and pricing of our overhead refurbishment work. There is also a $60m increase from FY26 onwards to improve vegetation management and better technology to inspect overhead lines.

9.4.2 Capex – asset replacement

There has been an increase of $87m in the asset renewal area. This is largely due to more emphasis being placed on the ageing underground network to ensure reliable supply and to accommodate increase demand as more electrification and EVs come online. There is also an increase as a result of greater detail around our substation project and design changes which have provided us with a firmer idea of the cost of these projects.

9.4.3 Connections / extensions

We anticipate growth in the residential housing sector will continue in the foreseeable future. A significant increase in the size, number of subdivision developments and an increase in medium density infill housing has driven the need for additional network reinforcement works to support this growth. The proposed government-led medium density residential standards bill will also increase the available areas for intensification across the Selwyn District and Christchurch City Council. These factors have contributed towards the need to increase our FY23 budget forecast and beyond by $68.5m.

9.4.4 Asset relocations

Apart from escalations in materials since last year, a proposed undergrounding project of a section of our 66kV network has increased this budget by $5m.

9.4.5 HV minor projects

Across the period we have increased this budget by $15m to strengthen the resilience of our network.

9.4.6 LV projects

This AMP introduces a proactive programme of reinforcement to ensure our LV network can facilitate the increased intensification and support the forecast penetration of EVs. This has added an additional $14.5m to the capex budget.

9.4.7 Major projects

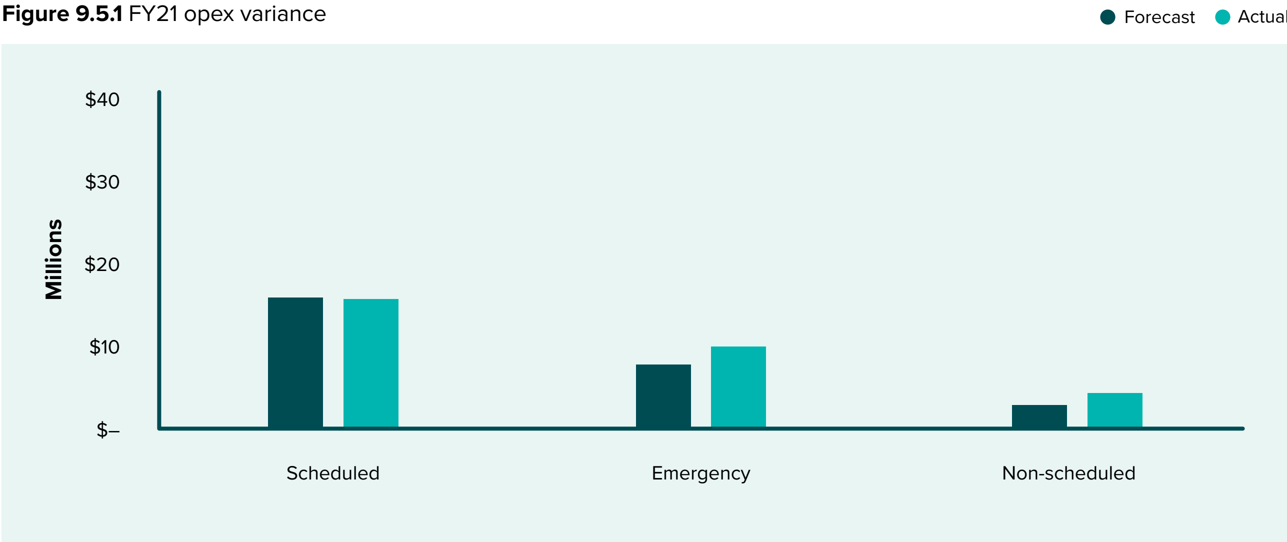
We anticipate many projects will be required to facilitate the connection of large-scale solar PV and to enable major industrial customers to transition their process heating requirements to electric to meet government emission targets. This combined with the increases in material costs has increased the budget by $54m.

9.5 Expenditure variation

9.5.1 Network opex variation

Our total network maintenance spend for FY21 of $27.0m was broadly consistent with our budget forecast of $30.5m. The breakdown is shown in Figure 9.5.1.

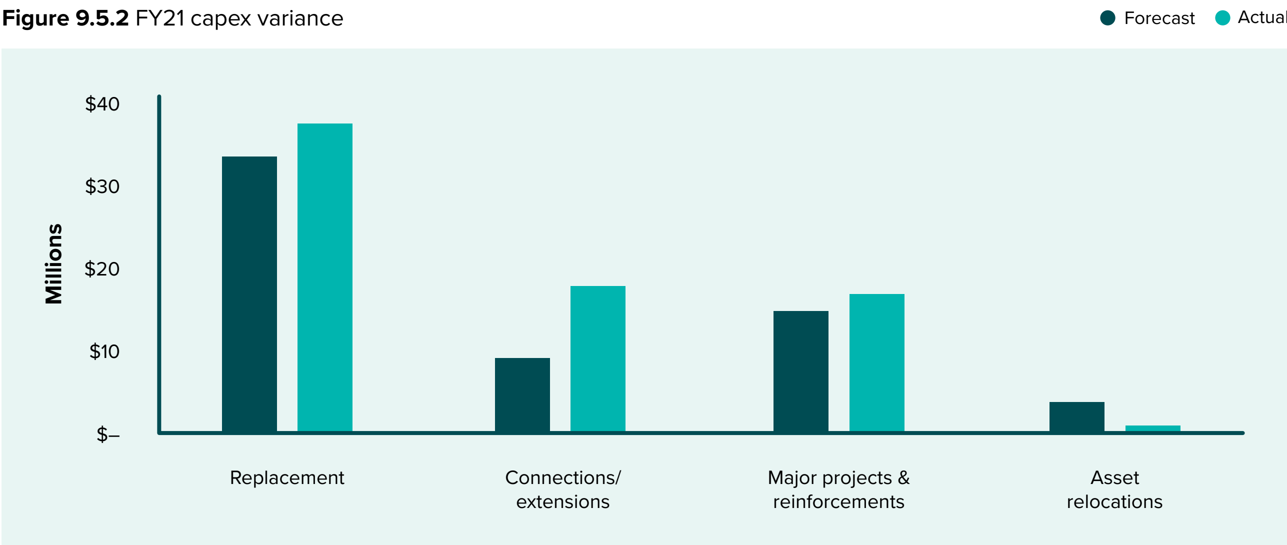
Figure 9.5.1 FY21 opex variance



9.5.2 Network capex variation

Our network capex actuals for FY21 were $73.8m, compared with our budget forecast of $61.9m. The breakdown is shown in Figure 9.5.2.

Figure 9.5.2 FY21 capex variance



Overall there was an over-expenditure of $11.9m. The majority of this is due to a higher than expected unit cost per customer connection. There is also an under-spend in asset relocations as some of the planned work driven by third parties did not go ahead.

10

Our ability to deliver

Photo: Connetics crew at our Hawthornden Substation in Avonhead installing three new 66kV cables delivering power from our Islington substation. This provides greater capacity, flexibility and resilience to support new and existing customers in that area.

Contents

10.1 Introduction

This section describes our:

- key philosophies, policies and processes that enable us to deliver our works programme and AMP objectives
- contract delivery process and how it enables us to consistently deliver our work safely, cost effectively and on time
- approach to works prioritisation and optimising resources

10.2 Service providers

Orion engages contractors and consultants, who we call service providers, to design, construct, maintain and dispose of our network assets.

Our service providers don't have direct network management responsibilities for our service – we engage them for specified scopes of work or for contracts over specific periods to meet the needs of our AMP objectives.

The key objective of our contractual relationships is to ensure the safety, quality and capability of both our people and the work being delivered. It will also ensure services and materials are delivered on time, at an agreed cost and to specified requirements. Our contracts are founded on AS/NZS standard conditions for capital, maintenance, and emergency works contracts.

Our Procurement Manual sets the framework for authorised service providers to meet our AMP objectives. Authorisation to undertake works on our network is subject to a formal contractual agreement which specifies the work categories that each service provider can undertake for us.

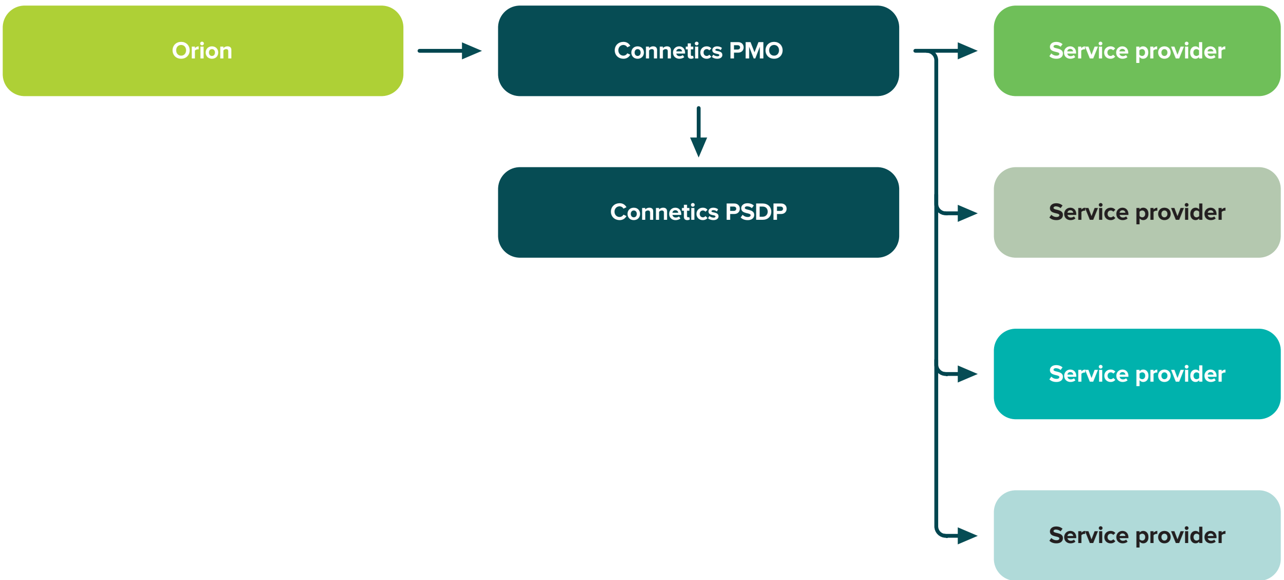
Service providers become responsible and accountable for the requirements of the base contract, and the specific conditions attached to specific projects or works orders.

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 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.

Figure 10.1 Orion contract delivery framework



10.3 Contract delivery

We have transitioned away from a lowest conforming tender model to a Primary Service Delivery Partner (PSDP) contracting model. Connetics undertakes the role of the PSDP and through the Project Management Office (PMO), contracts construction and maintenance services for overhead, substation and underground assets from Connetics and other service providers. The new contracting framework ensures we can deliver on our AMP and maintain resilience in our service providers.

The new contracting framework became operational in October 2021 and has positioned Orion to more effectively and efficiently meet the following outcomes:

- support and enhance safety
- drive increased quality and efficiency
- develop people within the Orion Group and across the industry
- deliver the resilience that Orion requires
- comply with our legal and regulatory framework
- contribute to Orion achieving its aspiration to be New Zealand's most advanced electricity network

This model ensures a suitable platform to achieve future sustainability, continued investment in people capability and competence and ensures our service providers have a dedicated focus on health, safety, quality and the environment.

Our Procurement and Land Services team maintains the contract and service level measures that are in place with Connetics.

Our Network Delivery team is responsible for ensuring our work is being delivered in a way that achieves long-term value for our customers. The team does this by monitoring and approving pricing as well as the service levels being achieved. This team is supported as appropriate by our operational and engineering teams.

Our Works Management information management system supports the above processes – including tenders, contracts, audit information and financial tracking.

Procurement of consultancy design services, property related services, vegetation management services and major equipment items are not a part of the PSDP model. Customer initiated work may be procured outside the PSDP model.

10.3.1 Works programme

Our customer initiated and growth projects are prioritised by our project prioritisation process, set out in Section 6. Our replacement and maintenance programmes are set out in Section 7.

10.3.2 Procurement

We adopt a risk based approach to our key procurement decisions, while ensuring levels of authority that allow for the efficient delivery of our AMP objectives. Our Procurement Policy outlines our strategic approach to procurement.

Our key network risks and our proposed network development priorities for the next period are outlined elsewhere in this AMP.

Our contract delivery process recommends formal procurement contracts with suppliers and service providers where the value and risk is considered high, complex, novel or likely to attract media attention, or come under significant public scrutiny. We have a variety of procurement options within our contract delivery framework which allow for flexible contract options and conditions.

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 sustainable value-add

Key policies which also provide procurement guidelines include our Delegations of Authority and Fraud and Theft policies. Our Delegations of Authority policy outlines our general expenditure and approval rules and details the expenditure authorities that allow our people to expediently deliver our AMP plan and objectives, including approved and unapproved expenditure. It also details authority limits for asset disposals, and research and development.

Our ability to deliver our AMP objectives relies on an appropriate level of competent, experienced, and skilled people within the Orion team, our PMO and our service providers.

10.3.3 Tenders

Tenders are our preferred method of engagement for the supply of major equipment.

We assess tenders for equipment supply following a robust assessment of process using weighted attributes such as price, technical support, experience and reputation.

For the delivery of our planned and unplanned works on overhead, substation and underground assets we utilise our PSDP, Connetics, through a dedicated arms-length Project Management Office (PMO), to plan and procure work from Connetics or a number of other service providers.

The PMO uses a fair price methodology for assessing and awarding works and apply unit rates where work is repeatable.

We aim to maintain the relationships we have with our service providers and seek to deliver our works at a whole of life cost that is in the long term interest of our customers.

10.3.4 Resourcing

Our ability to deliver our AMP objectives relies on an appropriate level of competent, experienced and skilled people – within the Orion team, our PMO and our service providers. The availability of sufficient and competent people is essential to the delivery of our planned capital and operational expenditure, our response to customer initiated upgrades, and our ability to respond to network faults, emergencies and natural disasters.

We proactively work with our PMO to assess the levels of people resources necessary to deliver our objectives, to the extent that is practical, while investing in competence and capability. This provides for a base level of ongoing planned work and people who can be quickly redirected to areas of greater need following High-Impact-Low-Probability events.

Our Works General Requirements places certain overarching obligations on our service providers:

- work shall be carried out safely, time mannerly and cost efficiently, while ensuring customer satisfaction
- only authorised personnel may undertake work on our network
- service providers shall have appropriate management systems in place to deliver contractual obligations
- the preferred methods and controls to plan, execute, monitor, control and close out works

Our Emergency Works Requirements covers our expectations for urgent work – for example, due to weather events, network failure or safety reasons. In this document we describe:

- the up-front resources and contingency measures we require service providers to have at all times
- how to prioritise emergency works
- the requirement for service providers to redeploy their resources to us in a major emergency
- the use of authorised personnel for emergency work
- the methods and controls for network access during emergency work
- the requirements for regular response and restoration time assessments
- the levels and controls for emergency spares

Where economically justified, we plan our activities to incentivise our PSDP and other service providers to grow and maintain the delivery resources we need:

- internal resources – the Orion team and its structure are described in Section 8 of this AMP. Section 8 also provides comprehensive overviews and the responsibilities of each business support area and how their capabilities help deliver our AMP objectives.
- service providers – we work with our service provider resources to ‘smooth’ our opex and capex works as much as practical to avoid unnecessary resource peaks and troughs. This has two key benefits. First, our service providers avoid the need to substantially ‘gear-up’ or ‘gear-down’ their resources for short term peaks. Second, it provides our service providers with more certainty.

10.3.5 Delivery

We deliver our programme of planned and emergency works using our PSDP framework, our service providers, and our in-house team based in our Christchurch office.

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. They use our robust contract delivery processes to safely construct, maintain and develop our network to achieve our objectives. Our other in-house teams, as shown in Section 8 of this AMP, provide and administer the vital business and information support functions which enable the successful delivery of our works programme.

We provide a highly responsive service to our customers and community when managing situations where our network capacity in localised areas may be constrained or compromised by other parties. We provide the ability for customers to connect to our network, or alter their connection type or capacity, in a timely manner.

10.3.6 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, conflicts of interest and contractual or technical non-conformances.

We review longer term contracts for continual performance improvement and to enable new initiatives as they arise.

We monitor our contract performance against our conditions of contract.

Our key objective when monitoring contract performance is continuous improvement including:

- enhanced collaborative and positive relationships with our PSDP and 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

10.3.7 Conclusions on our ability to deliver our forecast work programme

Historically we have been confident in our ability to deliver our forecast opex and capex programmes as detailed in our AMP.

The key reasons for this are:

- our plan is for a relatively smooth 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
- we have restructured our operational teams to efficiently deliver our work programme
- 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 support customer affordability
- we have a partnership approach with our PSDP and other service providers and by sharing our long term proposed works programme with them, they are able to plan ahead to resource to meet our needs
- we are continuing to invest in the capability of the Orion team

The impact of the global COVID-19 pandemic on costs and supply chains, in particular on manufacturing and shipping, and the possibility of further regional or national lockdowns creates uncertainty we must manage and mitigate. Currently we are experiencing some delays in long-lead time equipment, but these delays are not expected to have a major impact on our 10 year programme. We continue to monitor the situation and assess the impact on our short to medium term programme and manage as appropriate.

Our focus has always been on continuous improvement, and our PSDP framework will deliver long-term value to our customers and our stakeholders.

Other external factors could also impact our ability to achieve our programme of work. For example, other EDBs around New Zealand have increased their own opex and capex and this could put a strain on available resources. The only sustainable resolution to this increased demand is to increase the supply of skilled people. As an EDB, our key risk management approach to this issue is to clearly signal our forecast work programme so that service providers have the certainty they need to continue to invest in their people capability.

Through our Energy Academy initiative, we are also exploring options to increase wider industry training and competence development.

Connetics' base at Waterloo Business Park.

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.

Bio-diesel: 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.

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.

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.

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.

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
1. Summary of the plan	1 Executive summary
2. Background and objectives	2 About our business
	5 About our network
	8 Supporting our business
3. Assets covered	5 About our network
	7 Managing our assets
4. Service levels	4 Customer experience
5. Network development plans	6 Planning our network
	9 Financial forecasting
	10 Our ability to deliver
6. Lifecycle asset management planning (maintenance and renewal)	7 Managing our assets
	9 Financial forecasting
	10 Our ability to deliver
7. Risk management	3 Managing risk
8. Evaluation of performance	2 About our business
	4 Customer experience
	9 Financial forecasting

Appendix C Asset data

Data currently held in our information systems for the asset group can be found in the table below.

Data class	Network property	Overhead subtransmission	Overhead 11kV	Overhead 400V	Underground subtransmission	Underground 11kV	Underground 400V	Circuit breaker & switchgear	Power transformer & regulators	Distribution transformers	Protection systems	Communication cables	Communication systems	Distribution management system	Load management systems	Information systems	Generators	Monitoring
Location	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Type	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Age	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Seismic risk assessment	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Test/inspection results	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■
Ratings		■	■	■	■	■	■	■	■	■		■					■	
Serial numbers								■	■	■	■						■	■
Movement history								■	■	■	■							
Circuit diagrams		■	■	■	■	■	■	■	■		■	■	■					
Connectivity model		■	■	■	■	■	■					■						
Conductor size		■	■	■	■	■	■					■						
Joint details					■	■												
Pole ID labels		■	■	■														
Oil analysis										■	■							

Appendix D Specifications and standards (assets)

		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
Design standards	**Document ID**															
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															
Overhead line design technical manual	NW70.51.04															
Cable distribution design	NW70.52.01															
Distribution substation design	NW70.53.01															
Protection design	NW70.57.01															
Earthing system design	NW70.59.01															
Subtransmission protection design	NW70.57.02															
Distribution feeder and transformer protection	NW70.57.03															
SCADA functional specification for remote sites	NW70.56.01															
Substation design – customer premises	NW70.53.02															
Technical Specifications	**Document ID**															
Works general requirement	NW72.20.04															
Overhead line work	NW72.21.01															
Overhead line re-tighten components	NW72.21.03															
Tower painting	NW72.21.05															
Tower maintenance painting	NW72.21.06															
Tower inspections	NW72.21.19															
Overhead line inspection and assessment	NW72.21.11															
Thermographic survey of high voltage lines	NW72.21.10															
Standard construction drawing set – Overhead lines	NW72.21.18															

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
Vegetation work adjacent to overhead lines.	NW72.24.01	■	■	■												
Cable installation and maintenance	NW72.22.01				■	■	■	■								
Excavation, backfilling and restoration of surfaces	NW72.22.02				■	■	■	■								
Standard construction drawing set – Underground	NW72.21.20				■	■	■	■								
Cable testing	NW72.23.24				■	■	■	■								
Cabling and network asset recording	NW71.12.03				■	■	■	■								
Distribution cabinet installation	NW72.22.03						■									
Distribution box installation	NW72.22.10						■									
LV underground network inspection	NW72.21.12						■									
Unit protection maintenance	NW72.27.01							■					■			
Zone substation inspection	NW72.23.13								■	■						
Zone substation maintenance	NW72.23.07								■	■						
Disposal of asbestos	NW70.10.25								■	■						
Hazardous substances	NW70.10.02								■	■						
Standard construction drawing set – high voltage plant	NW72.21.21								■	■	■					
OCB servicing after operation under fault conditions	NW72.23.15								■							
Partial discharge tests	NW72.27.03								■							
Air break isolator maintenance – 11kV	NW72.21.04								■							
Distribution substation inspection	NW72.23.03								■		■					
Distribution substation maintenance	NW72.23.05								■		■					
Network substation inspection	NW72.23.04								■		■					
Network substation maintenance	NW72.23.06								■		■					
Environmental management manual	NW70.00.08								■		■					

		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**															
Power transformer servicing	NW72.23.25									✓						
Mineral insulating oil maintenance	NW72.23.01									✓						
Transformer installations (distribution)	NW72.23.16										✓					
Transformer maintenance (distribution)	NW72.23.02										✓					
Testing and commissioning of secondary equipment	NW72.27.04												✓			
Ripple control system details	NW70.26.01													✓		
Ripple equipment maintenance	NW72.26.02													✓		
SCADA master maintenance	NW72.26.04														✓	
SCADA RTU maintenance	NW72.26.05														✓	
Kiosk installation	NW72.23.14															✓
Graffiti removal	NW72.22.11															✓
Equipment Specifications	**Document ID**															
Poles – softwood	NW74.23.06		✓	✓												
Poles – hardwood	NW74.23.08	✓	✓	✓												
Insulators – high voltage	NW74.23.10		✓													
Conductor – overhead lines	NW74.23.17	✓	✓	✓												
Cross-arms	NW74.23.19	✓	✓	✓												
Earthing equipment and application	NW74.23.20		✓			✓	✓	✓								
Cable Subtransmission – 33kV	NW74.23.14				✓											
Cable Subtransmission – 66kV – 300mm2 Cu XLPE	NW74.23.30				✓											
Cable Subtransmission – 66kV – 1,600mm2 Cu XLPE	NW74.23.31				✓											
Cable Subtransmission – 66kV – 1,000mm2 Cu XLPE	NW74.23.35				✓											
Distribution cable 11kV	NW74.23.04					✓										
Distribution cable LV	NW74.23.11						✓									
Communication cable	NW74.23.40							✓								

		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
Equipment Specifications	**Document ID**															
Switchgear – 400V indoor	NW74.23.23								✓							
Circuit breaker – 66kV	NW74.23.25								✓							
Circuit breaker – 33kV indoor	NW74.23.28								✓							
Major power transformer 7.5/10MVA 66/11kV	NW74.23.07									✓						
Voltage regulator 11kV	NW74.23.15									✓						
Major power transformer 11.5/23MVA 66/11kV	NW74.23.16									✓						
Major power transformer 2.5MVA 33/11kV	NW74.23.22									✓						
Major power transformer 20/40MVA 66/11kV	NW74.23.24									✓						
Transformers – distribution	NW74.23.05										✓					
Ripple control system	NW74.23.09													✓		
Kiosk shell – full	NW74.23.01															✓
Kiosk shell – half	NW74.23.02															✓
Kiosk shell – quarter	NW74.23.03															✓
Asset management reports	**Document ID**															
AMR – Protection Systems	NW70.00.22												✓			
AMR – Power Transformers	NW70.00.23									✓						
AMR – Switchgear HV and LV	NW70.00.24								✓							
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							✓								
AMR – Cables – LV and Hardware	NW70.00.29						✓									
AMR – Cables – 11kV	NW70.00.30					✓										
AMR – Cables – 33kV	NW70.00.31				✓											
AMR – Cables – 66kV	NW70.00.32				✓											
AMR – Circuit Breakers	NW70.00.33								✓							

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 – 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 – Voltage Regulators	NW70.00.41															
AMR – Property – Corporate	NW70.00.42															
AMR – Property – Network	NW70.00.43															
AMR – Substations	NW70.00.44															
AMR – Vehicles	NW70.00.47															
AMR – Information Systems (Asset Management)	NW70.00.48															
AMR – Information Systems (Corporate)	NW70.00.49															

Appendix E 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
Demand side management stage 1 – issues and opportunities	NW70.60.10
Demand side management stage 2 – potential initiatives	NW70.60.11

Appendix F 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 NZ Ltd – AMP planning period: 1 April 2022 – 31 March 2032

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 22	31 Mar 23	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
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	15,121	22,207	22,823	20,649	18,472	17,388	20,099	21,904	24,181	25,299	26,015
11	System growth	18,172	14,358	10,433	17,364	24,075	13,629	20,381	22,438	16,948	21,550	21,704
12	Asset replacement and renewal	25,468	32,234	29,376	29,222	42,009	51,479	53,101	54,452	58,864	58,235	61,218
13	Asset relocations	2,735	7,560	8,055	1,936	1,664	1,712	2,737	2,604	2,954	3,109	3,155
14	Reliability, safety and environment:											
15	Quality of supply	7,281	14,439	20,925	7,662	14,099	20,775	11,088	7,520	10,991	9,241	8,068
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	7,298	15,2605	11,658	12,033	13,485	10,957	5,990	6,163	6,337	6,518	6,705
18	**Total reliability, safety and environment**	14,578	29,703	32,582	19,694	27,584	31,733	17,078	13,683	17,328	15,759	14,773
19	**Expenditure on network assets**	76,075	106,062	103,269	88,865	113,805	115,941	113,396	115,080	120,274	123,952	126,864
20	Expenditure on non-network assets	8,829	11,574	13,204	12,458	13,087	13,269	10,924	8,505	8,014	9,031	9,295
21	**Expenditure on assets**	84,904	117,636	116,473	101,323	126,892	129,210	124,320	123,585	128,288	132,983	136,159
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	2,900	8,062	10,243	3,272	2,141	2,149	2,611	2,372	2,440	2,510	2,550
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	82,004	109,575	106,230	98,051	124,751	127,060	121,709	121,213	125,848	130,474	133,609
29	Assets commissioned	87,004	87,004	86,575	78,713	78,533	86,397	82,021	83,271	72,618	60,220	60,921
32		**$000 (in constant prices)**										
33	Consumer connection	15,121	22,207	22,105	19,444	16,911	15,476	17,392	18,426	19,777	20,116	20,110
34	System growth	18,172	14,358	10,105	16,351	22,041	12,130	17,635	18,876	13,861	17,135	16,777
35	Asset replacement and renewal	25,468	32,234	28,453	27,517	38,459	45,818	45,948	45,808	48,142	46,304	47,322
36	Asset relocations	2,735	7,560	7,802	1,823	1,524	1,524	2,369	2,190	2,416	2,472	2,439
37	Reliability, safety and environment:											
38	Quality of supply	7,281	14,439	20,267	7,215	12,908	18,491	9,594	6,326	8,989	7,348	6,236
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	7,298	15,265	11,291	11,330	12,345	9,752	5,183	5,184	5,183	5,183	5,183
41	**Total reliability, safety and environment**	14,579	29,703	31,558	18,545	25,253	28,243	14,777	11,510	14,172	12,530	11,419
42	**Expenditure on network assets**	76,076	106,062	100,023	83,680	104,186	103,191	98,121	96,811	98,367	98,557	98,068
43	Expenditure on non-network assets	8,829	11,574	12,961	11,891	12,246	12,073	9,787	7,444	6,924	7,551	7,643
44	**Expenditure on assets**	84,905	117,636	112,984	95,571	116,432	115,264	107,908	104,255	105,291	106,108	105,711
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	2,735	7,560	7,802	1,823	1,524	1,524	2,737	2,604	2,954	3,109	3,155
49	Research and development	856	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232	1,232
50												

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 NZ Ltd – AMP planning period: 1 April 2022 – 31 March 2032

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
51												
52	For year ended	31 Mar 22	31 Mar 23	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
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	717	1,205	1,561	1,912	2,707	3,477	4,404	5,183	5,905
55	System growth	-	-	328	1,013	2,035	1,499	2,745	3,562	3,087	4,415	4,926
56	Asset replacement and renewal	-	-	923	1,705	3,551	5,661	7,153	8,645	10,722	11,931	13,895
57	Asset relocations	-	-	253	113	141	188	369	413	538	637	716
58	Reliability, safety and environment:											
59	Quality of supply	(0)	-	658	447	1,192	2,285	1,494	1,194	2,002	1,893	1,831
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	(0)	-	366	702	1,140	1,205	807	978	1,154	1,335	1,522
62	**Total reliability, safety and environment**	(0)	-	1,024	1,149	2,331	3,489	2,300	2,172	3,156	3,229	3,353
63	**Expenditure on network assets**	(0)	-	3,246	5,185	9,619	12,749	15,275	18,270	21,907	25,395	28,796
64	Expenditure on non-network assets	-	-	243	567	841	1,196	1,137	1,061	1,090	1,480	1,652
65	**Expenditure on assets**	(0)	-	3,489	5,752	10,460	13,945	16,412	19,331	22,997	26,875	30,448
68	**11a(ii): Consumer Connection**											
69	*Consumer types defined by EDB (see note)*	**$000 (in constant prices)**										
70	General Connections	4,931	9,904	8,454	8,483	8,448	7,724					
71	Large Customers	4,775	4,259	6,708	3,993	1,525	1,403					
72	Subdivisions	2,706	4,245	3,619	3,632	3,617	3,304					
73	Switchgear	884	714	690	692	689	633					
74	Transformers	1,825	3,085	2,634	2,643	2,632	2,412					
76	**Consumer connection expenditure**	15,121	22,207	22,105	19,444	16,911	15,476					
77	*less* Capital contributions funding consumer connections	1,119	2,974	4,658	2,027	1,043	996					
78	**Consumer connection less capital contributions**	14,002	19,232	17,447	17,417	15,868	14,480					
79	**11a(iii): System Growth**											
80	Subtransmission	6,231	8,071	2,607	6,317	6,132	2,196					
81	Zone substations	9,873	2,137	2,667	4,728	9,978	2,768					
82	Distribution and LV lines	-	549	794	1,254	1,895	3,078					
83	Distribution and LV cables	1,591	1,415	628	320	319	372					
84	Distribution substations and transformers	-	-	-	-	-	-					
85	Distribution switchgear	-	464	200	-	-	-					
86	Other network assets	477	1,723	3,210	3,732	3,716	3,717					
87	**System growth expenditure**	18,172	14,358	10,105	16,351	22,041	12,130					
88	*less* Capital contributions funding system growth	-	-	-	-	-	-					
89	**System growth less capital contributions**	18,172	14,358	10,105	16,351	22,041	12,130					
90												

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 NZ Ltd – AMP planning period: 1 April 2022 – 31 March 2032

91		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
92	For year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	940	1,422	1,137	181	1,200	4,030
95	Zone substations	6,262	7,969	3,229	2,677	8,917	10,789
96	Distribution and LV lines	6,358	6,577	8,645	9,219	10,805	13,425
97	Distribution and LV cables	746	817	606	608	711	712
98	Distribution substations and transformers	1,623	2,759	3,138	3,021	3,562	3,138
99	Distribution switchgear	6,047	7,719	8,337	8,866	10,018	10,459
100	Other network assets	3,492	4,970	3,361	2,944	3,244	3,266
101	**Asset replacement and renewal expenditure**	25,468	32,234	28,453	27,517	38,459	45,818
102	*less* Capital contributions funding asset replacement and renewal						
103	**Asset replacement and renewal less capital contributions**	25,468	32,234	28,453	27,517	38,459	45,818
107	**11a(v): Asset Relocations**						
108	*Project or programme*	**$000 (in constant prices)**					
109	NZTA	574	993	994	938	642	643
110	Christchurch City Council	960	1,308	1,309	293	292	292
111	Selwyn Disrtict Council	887	175	409	176	175	175
112	Developer / 3rd party	313	5,085	5,090	416	414	414
113	Ōtākaro	-	-	-	-	-	-
115	All other projects or programmes – asset relocations						
116	**Asset relocations expenditure**	2,735	7,560	7,802	1,823	1,524	1,524
117	*less* Capital contributions funding asset relocations	1,781	5,087	5,263	1,055	917	917
118	**Asset relocations less capital contributions**	954	2,473	2,538	769	607	607
122	**11a(vi): Quality of Supply**						
123	*Project or programme*	**$000 (in constant prices)**					
124	LV monitoring	856	1,232	1,296	1,307	1,290	-
	Northern Christchurch	5,929	-	-	-	-	6,912
	Region A 66kV resiliency	-	12,842	18,668	5,603	11,315	11,314
	Turners Road LCB	-	62	-	-	-	-
	Coleridge reliability improvement	355	-	-	-	-	-
125	Comms associated with Entec line switches	115	223	223	224	223	223
126	Ferroresonance capacitor replacement	26	80	80	80	80	42
127		-	-	-	-	-	-
128		-	-	-	-	-	-
130	All other projects or programmes – quality of supply						
131	**Quality of supply expenditure**	7,821	14,439	20,267	7,215	12,908	18,491
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	7,821	14,439	20,267	7,215	12,908	18,491

Schedule 11a. Report on forecast capital expenditure continued

Company name: Orion NZ Ltd – AMP planning period: 1 April 2022 – 31 March 2032

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
135							
136	For year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme*	**$000 (in constant prices)**					
139	N/A						
140							
141							
142							
143							
145	All other projects or programmes – legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme*	**$000 (in constant prices)**					
153	Papanui 11kV reconfiguration	-	317	-	-	-	-
154	Resilience		1,062	1,063	1,066	2,124	2,124
155			-	-	-	-	-
	11kV Red/Orange tagged pole repl.		2,883	2,886	2,896	2,884	2,884
156	LV ties replacement with Krone	251	255	170	171	170	170
157	Supply Fuse Relocation Programme	7,047	10,748	7,172	7,198	7,167	4,574
159	All other projects or programmes – reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	7,298	15,265	11,291	11,330	12,345	9,752
161	*less* Capital contributions funding reliability, safety and environment		-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	7,298	15,265	11,291	11,330	12,345	9,752
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme*	**$000 (in constant prices)**					
169	Plant and vehicles	1,176	1,365	859	971	1,059	834
170	Information technology	6,230	8,757	11,333	9,330	10,356	9,985
171	Corporate land and buildings	789	290	291	707	408	794
172	Tools and equipment	634	1,162	478	883	423	460
173		-	-	-	-	-	-
175	All other projects or programmes – routine expenditure	-	-	-	-	-	-
176	**Routine expenditure**	8,829	11,574	12,961	11,891	12,246	12,073
177	**Atypical expenditure**						
178	*Project or programme*						
179	N/A						
180							
181							
182							
183							
185	All other projects – atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
188	**Expenditure on non-network assets**	8,829	11,574	12,961	11,891	12,246	12,073

Schedule 11b. Report on forecast operational expenditure continued

Company name: Orion NZ Ltd – AMP planning period: 1 April 2022 – 31 March 2032

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7												
8	For year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	8,200	7,493	7,712	7,925	8,092	8,312	8,543	8,780	9,023	9,270	9,529
11	Vegetation management	4,520	5,024	5,277	5,530	10,187	10,464	10,755	11,053	11,359	11,671	11,996
12	Routine and corrective maintenance and inspection	12,940	15,457	15,628	16,063	22,181	23,115	23,918	24,631	25,473	25,909	26,174
13	Asset replacement and renewal	2,475	2,401	2,054	2,155	3,067	3,793	3,585	3,500	3,476	4,486	4,610
14	**Network Opex**	28,135	30,375	30,671	31,673	43,527	45,685	46,801	47,964	49,331	51,335	52,309
15	System operations and network support	17,695	18,246	19,941	21,198	21,090	21,914	22,408	23,064	23,751	24,501	25,276
16	Business support	19,819	20,254	23,948	26,325	26,069	27,344	28,855	30,693	32,580	34,663	37,166
17	**Non-network opex**	37,514	38,500	43,889	47,523	47,159	49,258	51,263	53,757	56,331	59,164	62,442
18	**Operational expenditure**	65,649	68,875	74,560	79,196	90,686	94,943	98,064	101,721	105,662	110,499	114,751
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	8,200	7,493	7,497	7,496	7,447	7,444	7,445	7,445	7,445	7,443	7,445
23	Vegetation management	4,520	5,024	5,129	5,231	9,376	9,372	9,372	9,373	9,373	9,371	9,372
24	Routine and corrective maintenance and inspection	12,940	15,457	15,191	15,193	20,415	20,701	20,843	20,887	21,019	20,803	20,449
25	Asset replacement and renewal	2,475	2,401	1,996	2,038	2,823	3,397	3,124	2,968	2,868	3,602	3,602
26	**Network opex**	28,135	30,375	29,813	29,958	40,061	40,915	40,785	40,673	40,705	41,218	40,868
27	System operations and network support	17,695	18,246	19,245	19,847	18,996	19,122	19,329	19,361	19,289	19,280	19,310
28	Business support	19,819	20,254	23,190	24,789	23,850	24,333	24,966	25,837	26,657	27,562	28,702
29	**Non-network opex**	37,514	38,500	42,435	44,636	42,846	43,455	44,295	45,198	45,946	46,842	48,012
30	**Operational expenditure**	65,649	68,875	72,248	74,594	82,907	84,370	85,080	85,871	86,651	88,060	88,880
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	2,569	2,879	3,269	3,713	4,219	4,795	5,452	6,200	7,053	8,025	9,132
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	216	429	644	868	1,098	1,335	1,578	1,827	2,084
43	Vegetation management	-	-	148	300	811	1,093	1,382	1,680	1,986	2,300	2,624
44	Routine and corrective maintenance and inspection	-	-	437	870	1,766	2,414	3,074	3,744	4,454	5,106	5,725
45	Asset replacement and renewal	-	-	57	117	244	396	461	532	608	884	1,008
46	**Network Opex**	-	-	858	1,715	3,466	4,770	6,016	7,291	8,626	10,117	11,441
47	System operations and network support	-	-	696	1,351	2,094	2,792	3,079	3,703	4,462	5,221	5,966
48	Business support	-	-	758	1,536	2,219	3,011	3,889	4,856	5,923	7,101	8,464
49	**Non-network opex**	-	-	1,454	2,887	4,313	5,803	6,968	8,559	10,385	12,322	14,430
50	**Operational expenditure**	-	-	2,312	4,602	7,779	10,573	12,984	15,850	19,011	22,439	25,871

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%	1%	26%	50%	23%	-	3	1%
11	All	Overhead Line	Wood poles	No.	1%	7%	18%	21%	54%	-	3	13%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	13%	50%	37%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	13%	86%	1%	-	3	13%
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	-	-	-	84%	16%	-	3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	7%	37%	32%	24%		3	4%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	7%	41%	44%	7%	-	3	48%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	51%	20%	30%	-	3	46%
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.	-	-	8%	3%	90%	-	4	5%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	29%	5%	66%	-	4	14%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	

Schedule 12a Report on asset condition continued

36					Asset condition at start of planning period (percentage of units by grade)							
37					H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset to be replaced in next 5 years
38	Voltage	Asset category	Asset class	Units								
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	3%	14%	44%	38%	-	3	4%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	9%	37%	54%	-	3	9%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	-	15%	24%	61%	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0%	1%	99%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	25%	48%	26%	1%	3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) – reclosers and sec	No.	-	-	-	6%	94%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	51%	11%	38%	-	4	24%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	5%	10%	53%	32%	-	2	8%
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.	-	-	13%	25%	62%	-	4	7%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0%	1%	12%	23%	64%	-	3	6%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	18%	23%	58%		3	6%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	27%	-	73%		3	13%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0%	0%	16%	44%	39%		3	1%
55	LV	LV Line	LV OH Conductor	km	-	0%	11%	60%	28%	0%	3	-
56	LV	LV Cable	LV UG Cable	km	-	-	0%	17%	83%	-	3	0%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100%	1	-
58	LV	Connections	OH/UG consumer service connections	No.			5%	85%	10%		1	5%
59	All	Protection	Protection relays (electromechanical, solid state)	No.	-	-	19%	21%	61%		3	20%
60	All	SCADA and communications	SCADA and comms equipment operating as a single system	Lot	5%	0%	15%	45%	35%	0%	2	67%
61	All	Capacitor Banks	Capacitors including controls	No.					100%		2	-
62	All	Load Control	Centralised plant	Lot	-	16%	57%	20%	7%		3	34%
63	All	Load Control	Relays	No.						100%	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 11kV #1	16	30	N-1	16	54%	30	63%	No constraint within +5 years	
10	Addington 11kV #2	18	30	N-1	18	59%	30	60%	No constraint within +5 years	
11	Armagh	18	40	N-1	18	46%	40	54%	No constraint within +5 years	
12	Barnett Park	10	15	N	10	64%	15	64%	No constraint within +5 years	Single 66kV line and 23MVA transformer backed up by 11kV but limited to 15MVA by compliance with security of supply standard
13	Bromley	32	60	N-1	32	54%	48	69%	No constraint within +5 years	
14	Dallington	28	40	N-1	28	70%	40	71%	No constraint within +5 years	
15	Fendalton	35	40	N-1	35	88%	40	87%	No constraint within +5 years	
16	Halswell	19	23	N-1	19	82%	46	49%	No constraint within +5 years	Install 3rd transformer when needed
17	Hawthornden	33	40	N-1	33	82%	40	84%	No constraint within +5 years	
18	Heathcote	23	40	N-1	23	58%	40	60%	No constraint within +5 years	
19	Hoon Hay	30	40	N-1	30	74%	40	76%	No constraint within +5 years	
20	Hornby	13	20	N-1	13	67%	20	69%	No constraint within +5 years	
21	Ilam	7	11	N-1	7	65%	11	68%	No constraint within +5 years	
22	Lancaster	17	40	N-1	17	43%	40	45%	No constraint within +5 years	
23	McFaddens	35	40	N-1	35	88%	40	89%	No constraint within +5 years	
24	Middleton	26	40	N-1	26	66%	40	69%	No constraint within +5 years	
25	Milton	35	40	N-1	35	88%	40	91%	No constraint within +5 years	Load transfer to Addington when needed
26	Moffett	14	23	N-1	14	63%	23	71%	No constraint within +5 years	
27	Oxford Tuam	15	40	N-1	15	39%	40	41%	No constraint within +5 years	
	Papanui	42	48	N-1	42	87%	48	92%	Other	Install new Belfast zone substation to alleviate 11kV constraint which also avoids emerging transformer constraint
	Prebbleton	7	15	N	7	48%	15	58%	No constraint within +5 years	
	Rawhiti	30	40	N-1	30	75%	40	74%	No constraint within +5 years	
	Shands	13	20	N-1	13	65%	20	87%	No constraint within +5 years	
	Sockburn	23	39	N-1	23	58%	39	58%	No constraint within +5 years	
	Waimakariri	19	40	N-1	19	48%	40	51%	No constraint within +5 years	
	Annat	4	-	N	2	-	-	-	No constraint within +5 years	
	Bankside	4	-	N	3	-	-	-	No constraint within +5 years	
	Brookside 66kV	9	-	N	6	-	-	-	No constraint within +5 years	
	Darfield	5	-	N	4	-	-	-	No constraint within +5 years	
	Diamond Harbour	2	-	N	2	-	-	-	No constraint within +5 years	
	Dunsandel	20	23	N-1	14	86%	23	86%	No constraint within +5 years	
	Duvauchelle	5	8	N-1	5	70%	8	68%	No constraint within +5 years	
	Greendale	7	-	N	5	-	-	-	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
	Highfield	8	-	N	6	-	-	-	Transformer	Transfer to Norwood when Burnham zone substation is built
	Hills	7	-	N	5	-	-	-	No constraint within +5 years	
	Hororata	8	-	N	6	-	-	-	No constraint within +5 years	
	Killinchy	9	-	N	6	-	-	-	No constraint within +5 years	
	Kimberley	15	23	N-1	11	67%	23	66%	No constraint within +5 years	
	Larcomb	14	23	N-1	10	62%	23	73%	No constraint within +5 years	
	Lincoln	10	10	N-1	7	103%	10	98%	Transformer	Constraint to be resolved by transfers to Springston zone substation
	Little River	1	-	N	1	-	-	-	No constraint within +5 years	
	Motukarara	3	8	N-1	3	45%	8	45%	No constraint within +5 years	
	Rolleston	10	10	N-1	7	98%	23	49%	Transformer	Load shift to Highfield zone substation then new Burnham zone sub
	Springston 66/11kV	7	-	N	5	-	23	49%	Transformer	Staged upgrade to 2 x 23MVA transformers
	Te Pirita	9	-	N	6	-	-	-	Transformer	Transfer to Hororata if needed
28	Weedons	14	23	N-1	10	62%	23	80%	No constraint within +5 years	

Schedule 12c Report on forecast network demand

		Current year	CY+1	CY+2	CY+3	CY+4	CY+5
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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
11	*Consumer types defined by EDB**						
12	Streetlighting	25	25	15	15	15	15
13	General	5,045	6,335	3,465	3,465	3,465	3,465
14	Irrigation	10	15	5	5	5	5
15	Major Customer	20	25	15	15	15	15
16	Large Capacity	-	-	-	-	-	-
17	**Connections total**	5,100	6,400	3,500	3,500	3,500	3,500
18							
19	**Distributed generation**						
20	Number of connections	520	1,110	1,000	1,000	1,000	1,000
21	Capacity of distributed generation installed in year (MVA)	6	12	20	120	70	10
22	**12c(ii) System Demand**						
23							
24	**Maximum coincident system demand (MW)**						
25	GXP demand	624	639	651	663	675	687
26	*plus* Distributed generation output at HV and above	2	2	2	2	2	2
27	**Maximum coincident system demand**	626	641	653	664	676	688
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	626	641	653	664	676	688
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	3,419	3,467	3,516	3,565	3,615	3,665
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	13	15	16	17	18	19
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	3,433	3,482	3,531	3,582	3,633	3,685
36	*less* Total energy delivered to ICPs	3,293	3,340	3,387	3,436	3,485	3,535
37	**Losses**	140	142	144	146	148	150
38							
39	**Load factor**	63%	62%	62%	62%	61%	61%
40	**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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
10	**SAIDI**						
11	Class B (planned interruptions on the network)	13.2	13.2	13.2	13.2	13.2	13.2
12	Class C (unplanned interruptions on the network)	66.5	66.5	66.5	66.5	66.5	66.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.15	0.15	0.15	0.15
15	Class C (unplanned interruptions on the network)	0.84	0.84	0.84	0.84	0.84	0.84

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	The Asset Management Policy is embedded into the AMP 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. Orion plans to separate the AM Policy from the AMP so that this key document can be more easily shared, updated, and separately signed off in future. A copy will still be referenced within the AMP.	Widely used asset management practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., 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?	3.75	The Orion NZ Asset Management Strategy was updated in 2021 and signed off by the Orion board on 17 March 2021. This document is imbedded within the AMP 2021 document in section 2.8. The AM Strategy aligns with our group strategy. Also, Orion are currently looking at an option to re-establish the Asset Management Strategy as a standalone SAMP document and have this updated/endorsed separately. A copy of the current SAMP is then likely to be placed into the latest AMP.	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 (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.

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.
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.	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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.75	This is embodied in the asset management strategy focus areas and objectives. This is detailed in section 2.8 of the asset mamagement plan. This has been improved to align with our group strategy and the strategic themes within that.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3.75	Orion's asset management work plan is documented broadly within the AMP. Detailed work plans are documented and sit with the Network Programme team. Individual asset management reports (AMR) are made available and detail the lifecycle activities for each asset class. The creation and ongoing maintenance of these documents sit with the appropriate stakeholder within the business but are largely controlled by the engineering and lifecycle teams. All of these documents have been updated to align with the business strategy.	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 optimise 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?	3.75	The current 2021 AMP Update 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 AMP is available throughout the organisation and via the online intranet site. Service providers are also updated annually on key programmes of work in the AMP.	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?	3.75	Responsibility for AMP actions and focus is now included in staff Statements of Accountability and Contractors scopes of work. Ongoing training and awareness of the drivers within the latest AMPs continues.	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.

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
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.
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.
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.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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)	3.75	Forward funding plans are drafted annually, with appropriate cost benefits, risk management and AM Strategy targets identified. Routine activities and targeted capital improvement projects are planned and funded to ensure the available contractor resources can complete these activities within the scheduled time frames. Orion works closely with its service providers and is looking to improve the procurement of these services. The Annual Work Plan continues to be the core communication as to what activities are planned. There is a robust process to manage the approval of forward projects and their inclusion onto the Annual Work Plan.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3.75	During the recent period of the COVID-19 Lockdown Restrictions (Level 4 and 3), Orion NZ managed their response to this situation via their Crisis Management Team (CMT) structure. This enabled the organisation to effectively manage and support all of their staff and key contractors though this unique situation in New Zealand. There are 42 documented emergency management plans on the company intranet. These are reviewed every two to three years. Many other improvement areas have been noted.	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	Responsibility for AMP actions and focus is now included in staff Statements of Accountability and Contractors scopes of work. Ongoing training and awareness of the drivers within the latest AMPs continues. The structure ensures a focus on core business and provides the roles to maintain focus on asset management plan delivery.	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 e.g., 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.

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
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.
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.
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.*

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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	The structure,for authority and responsibilities is imbedded within the AMP 2021 document in section 2.11 Accountabilities and responsibilities In light of a refreshed business strategy structure, authority and responsibilities are being reviewed and reorganisation of resources will follow. A new Group CEO position is to be established, which is responsible for Orion, plus Connetics and the Energy Academy. This leadership alignment aims to improve the overall effectiveness of the group and enable more collaboration together.	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	See above Delivery of asset management requirements is embodied in the strategy, clearly signaled and communicated as important through the foundation purpose to be "New Zealands most advanced electricity network" Orion and Connetics are planning to develop a new Project Management Office (PMO) which will be set up to manage all outsourcing activities. The PMO will sit between the Orion organisation and the five main contracting organisations. The PMO service is provided by Connetics and will take the place of the current Orion Contract Managers.	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 (e.g., 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-about would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3.75	Orion NZ are continuing to evolve outsourcing with outsourcing and procurement of asset management processes. We believe that the contractors utilised are a good fit for the goals that Orion NZ is striving to achieve. An updated Procurement Manual is now available. Includes Procurement Framework diagrams. Set up of the new PMO, as noted above.	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 (e.g., 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.

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
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard.

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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	Orion NZ is assisting core contractor organisations to development entry level staff in roles aligned with Orion NZ's asset management improvement initiatives. During our discussion with Orion NZ, WSP were given a presentation on a new initiative which Orion NZ and Connectics are developing together with a focus on growing capability. A Training Academy Presentation was delivered to WSP. It is hoped that this new training initiative pilot will lead to other EDBs joining in and developing this industry specific training programme. This is a training area that does not exist currently for EDBs and both organisations have taken this leadership role to ensure core industry training options can be developed for the future.	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?	3.75	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 for network access is well managed, with information housed in Orion NZ's PowerOn application, while competency management processes are carefully documented. Refer Training	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. (e.g., PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3.75	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 for network access is well managed, with information housed in Orion NZ's PowerOn application, while competency management processes are carefully documented. Orion personnel are heavily involved in review and publication of industry safety rules which underpin competency and safety on the network. The dedicated Orion network training team is growing and developing new training programmes, such as: Network and field service training – • 3-day training at a specialised local training facility, plus ongoing refresher training. • 2 yearly refresher training for Control Room Operators Orion has recently joined the Stay Live group, along with a number of other network organisations. The aim is to build more consistent processes and to learn from other group members.	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.

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
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities – including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities – internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. *The assessor is advised to note in the Evidence section why this is the case and the evidence seen.*

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.75	Additional staff have been added to improve the community engagement area and to work closer with community groups. Orion's Net Promotor Score indicates that is a high level of community trust for Orion. Orion works closely with its service providers.	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	Documentation such as the AMP, Asset Management Policy, Asset Management Report's, and Business Cases exist to describe the main elements of Orion's asset management system. Every document has an Orion owner and a review date. A new process to digitalise field asset data is underway. The first assets to be trialled is the Network Pole Inspections. A new process and field devices are now available for the inspection data to be entered into. This provides a more consistent data collection process and asset condition rating scoring for asset management planning. Other asset areas such as substations will be trialled next.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e., the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g., s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3.25	The AMP details the broad range of information and applications in place to support Orion NZ'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 NZ have in the past, chosen "best of breed" (as opposed to an integrated system) and this is considered appropriate for this organisation as it has been well integrated. However due to data governance improvement requirements, new technology will be required in the future. Data and digitisation strategy (KMPG)	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.

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
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.
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.*

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.25	Orion NZ's aim is to seamlessly gather, store and package specifically requested field findings in their Asset Register from various asset and maintenance inspections. Basix offers this additional functionality and whilst currently under development, progress is being made towards autonomously storing data and photographs from the field to enable the packaging of specific works based on priority, location and asset type. The potential for greater visibility and reporting capability is a significant driver towards the success of this initiative. Data and digitisation is recognised as an enabling factor in the Group Strategy. Improved pole inspection programme using fulcrum (mobile data collection)	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 (e.g., 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?	3.5	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. In line with planned improvements for data and digitisation the GIS and Basix systems are to be reviewed as they have now reach their end of life. Have begun using the ProMapp application to develop Standard Operating Procedures for core processes, to prove a link to core process documents, provide consistent process execution and to ensure improved process change control.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/ or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3.5	Orion NZ has Condition Based Risk 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 with a risk based approach. They provide a proven and industry accepted means of prioritising risk and health to determine optimal level of capex renewals. This CBRM model continues to be developed. The CBRM model is one of the tools used to inform our decision making for asset replacement. Climate Change Opportunities and Risks for Orion - Report created	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 (e.g., 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.

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
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.
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.
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.*

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
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?	3.5	More asset information is being digitalised and more applications are being integrated with each other • Training / competency records – linking to PowerON • ProMapp – linking to various approved documents and data	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?	3.75	Orion has a comprehensive Orion Statutory Compliance Manual that provides company guidance and a risk and audit committee of the board as well as specialist roles that support our compliance.	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 *(e.g., 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?	3.5	Orion NZ 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. 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 AMRs. The Orion Condition Based Risk Management (CBRM) models for the majority of network assets are now well developed and are being used to make informed decisions on asset replacement programmes.	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 *(e.g., PAS 55 s 4.5.1)* require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3.5	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. Work quality audits are taken in field.	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 *(e.g., 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.

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
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.
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.
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.
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.*

Schedule 13 Report on asset management maturity continued

No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented info
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3.5	Project works and maintenance activities continue to be closely managed by Orion staff to ensure agreed standards are maintained. Orion NZ have recently 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 KPIs. A new condition assessment approach trialled on hardwood poles has found a large number of unknown underground level pole rot issues. Once found these poles are 'Red Tagged' and replaced within 48 hours. Data and digitisation for condition assessment information is being increased.	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?	3.5	Major failures and incidents are investigated on a case by case basis and escalated to senior management for review. 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. Ongoing improvements in fault indication and additional remotely controlled devices across the network is expected to improve this performance over time. Large scale storms across the network will continue to be a challenge to achieving this target. WSP reviewed an additional report provided by Orion for the Hastings Street Investigation Report. This is a very comprehensive investigation of an asset failure event. The investigation conclusions seem reasonable considering the information available after the fault. Luckily damage was restricted to this asset. This report shows that the current asset failure investigation processes within Orion are undertaken to a high standard, with a high degree of fact-based evidence being collected and reported on post event. Clearly the aim of these investigations is to understand the cause of the event and to target process improvement initiatives for future similar activities.	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 customers. 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))?	3.25	Over the past year there has been a continued focus on undertaking more audits of processes, by both internal (through our business assurance programme) 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. Internal Audit Programme: An annual business assurance programme is created and managed through oversight by a dedicated staff member whose focus is on the completion of the planned internal audit programme.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements *(e.g., 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
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	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.	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	Orion carries out both engineering and safety reviews to identify learnings from events and facilitate continual improvement. Documented procedures 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. As the needs of Orion's end users change, the network needs to also look to change. Orion is developing a network transformation roadmap to lay out continual improvement requirements for network performance and services. A full review of data and digitisation is also planned. New technologies and electricity demand requirements are starting to impact the current network and are expected to increase. • Distributed Energy Resources (DER) – customer generating their own power (solar and wind) • Advanced digital technology – customers enabled to gain improve information and management options • New consumption options – EV's and other low carbon options	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?	3.5	Orion NZ encourages its staff to attend industry events and seek out new innovations with suppliers and peer organisations. Orion is looking at areas such as software applications, SF6 free switchgear, Control Centre system upgrades and alarm rationalisation project, just to name a few. Broad networking including across other sectors helps to identify new technologies and approaches that could benefit our 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 *(e.g., 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.
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.
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 G Mandatory explanatory notes on forecast information

Company name: Orion NZ Ltd

For year ended: 31 March 2022

Schedule 14a Mandatory explanatory notes on forecast information

Box 1: Comment on the difference between nominal and constant price capital expenditure forecasts

In our AMP we have disclosed our:

- constant price (real) opex and capex forecasts
- nominal opex and capex forecasts for the ten years FY22 to FY31 inclusive.

In escalating our real forecasts to nominal forecasts, we have:

- split our forecast opex and capex into a number of groups
- forecast an escalation index for each group that represents a reasonable proxy for forecast movements in unit costs for each group
- applied the forecast escalation indices for the ten-year forecast period.

We applied forecast opex and capex escalators as follows:

- network labour – NZIER labour index forecasts to FY24, extrapolated by PwC to FY31
- non-network labour – NZIER forecasts to FY24, extrapolated by PwC to FY31
- other – NZIER producer price index (PPI) forecasts to FY25, extrapolated by PwC to FY31.

Box 2: Comment on the difference between nominal and constant price operational expenditure forecasts

- Please refer to Box 1 above.

Appendix H Certificate for year-beginning disclosures

Schedule 17. Certificate for year-beginning disclosures

We, Jane Taylor and Bruce Gemmell, 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 2.6.1 and 2.6.6 of the Electricity Distribution 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's corporate vision and strategy and are documented in retained records.

	28 March 2022
Director	Date
	25 March 2022
Director	Date

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