OtagoNet

The 33,000 volt power line to Kaitangata, rebuilt in 2022/23

Asset Management Plan Update 2024 – 2034

Publicly disclosed in March 2024

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Asset Management Plan Update

The OtagoNet Joint Venture has chosen to disclose an Asset Management Plan (AMP) update for the 2024/25 regulatory year and not a full AMP. In this document the updates are indicated in black font and the lighter, grey font indicates the information supplied in the 2023/24 AMP. This is done for ease of reference to the previous information.

Section 10 – Evaluation of Performance and Annexure 3 – Disclosure Schedules contain the latest, fully updated information and the 2023/24 information is not included in these sections.

Enquiries

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Liability Disclaimer

The information and statements made in this AMP are prepared on assumptions, projections, and forecasts. It represents OtagoNet Joint Venture's intentions and opinions at the date of issue (31 March 2024).

Due to global uncertainties, assumptions and forecasts in the AMP may prove to be wrong, events may occur that were not predicted, and OtagoNet Joint Venture could decide to take different actions than planned. OtagoNet Joint Venture may also change any information in this document at any time. OJV accepts no liability for any action, inaction, or failure to act based on this AMP.

Foreword

About OtagoNet

OtagoNet is the electricity lines business that provides electricity to most of rural Otago and to Frankton, supplying approximately 20,300 customer connections across the following networks:

- OtagoNet Joint Venture (OJV), which distributes power to customers in rural and coastal Otago.
- The Lakeland Network, which supplies to the Frankton and the Queenstown Lakes area, along with the embedded networks in Wānaka and Cromwell.

Established in 2002, OJV delivers a safe, efficient and reliable power supply to over 15,600 customers spread across a vast area of the rural and coastal Otago region that surrounds Dunedin City, from Shag Point in the North-East, through to St Bathans and then South to the Chaslands. It was formed following the purchase of the electricity network assets from shareholders of the consumer co-operative company, Otago Power Limited, and is jointly owned by The Power Company Limited, TPCL (75.1% share) and Electricity Invercargill Limited, EIL (24.9% share).

In addition to the OJV network, the Lakeland Network Limited (LNL), which is based in the Queenstown Lakes area, falls under the regulatory reporting of OtagoNet. Established by TPCL and EIL in 1995, it was formerly known as Electricity Southland Limited but was rebranded in 2021 to the 'Lakeland Network'. LNL provides a network that powers almost 5,000 customers, delivering the electrical capacity required to meet the needs of the continually growing local community. This modern network is built entirely underground and is reticulated in the Frankton Flats area. It extends to the Eastern corridor across the Shotover River to supply the Shotover Country subdivision, the Queenstown Country Club retirement village, Bridesdale and Kawarau Heights subdivisions, with future growth planned for the Ladies Mile area. It also brings electricity to the Southern corridor – from the Kawarau Bridge to the Kawarau Falls area and extends South to supply the fast-growing Hanley's Farm subdivision. LNL also manages the embedded networks in Wānaka, comprising Northlake, Clearview and Hikuwai subdivisions and the Wooing Tree subdivision in Cromwell.

This Asset Management Plan (AMP) outlines OtagoNet's approach to managing its electricity distribution assets across both the OJV and Lakeland networks during the period from 1 April 2024 to 31 March 2034. Our AMP showcases how we plan to invest in these networks over this 10-year period so that we can continue to provide a safe, efficient and reliable power supply to the customers we serve.

About our Network Manager, PowerNet

PowerNet is an electricity management company with head offices based in Invercargill. It is a joint venture company owned (50/50) by Electricity Invercargill Limited (EIL) and The Power Company Limited (TPCL).

EIL and TPCL established PowerNet in 1994 to achieve economies of scale through integrated network management across the Southern region's Electricity Distribution Businesses (EDBs). It manages the non-exempt EDBs of OtagoNet and EIL, the exempt EDB of TPCL, and the non-grid-connected Stewart Island Electric Supply Authority (SIESA).

PowerNet manages an asset base and investments in excess of NZ$1.1 billion. It provides services to 76,000 customers through more than 14,200 circuit kilometres and manages the fourth-largest suite of EDB assets in New Zealand. In addition to OtagoNet (which operates OJV across the coastal and inland region of Otago and the Lakeland network in Frankton, Cromwell and Wānaka), EIL operates in Invercargill and Bluff, TPCL operates in Southland and West Otago, and SIESA on Stewart Island.

PowerNet has long term management agreements in place with OJV and LNL, EIL and TPCL. With the benefit of integrated business management systems in place, significant people capability and capacity, and a core purpose and expertise in asset management, PowerNet has remained a high-performing asset manager for OtagoNet. This has been judged by the value and efficiency in managing OtagoNet networks and the delivery against the key performance indicators (KPIs) regularly reviewed and re-set as part of the management agreement.

PowerNet's continued commitment to improvement across asset management, workplace safety and operational efficiency, coupled with a focus on commercial growth and business development, ensures customers continue to receive a safe, reliable and efficient power supply.

Asset Management Capability

Central to PowerNet's lifecycle asset management approach is the ability to balance cost, risk, and performance according to stakeholder requirements. Asset management is at the core of PowerNet's business capability, and its importance is reflected in the continued management of intergenerational assets across a number of local network companies in the Southern region.

PowerNet's network management maturity and capability provide strong asset management practices and a structured approach to asset management - from fleet plans for asset classes, to structured inspection and testing regimes for ground-mounted assets (poles, transformers, main ring units, air break switches) and underground assets such as cables.

PowerNet's development of this Asset Management Plan (AMP) ensures OJV's objectives will be met, together with meeting our regulatory reporting obligations. It outlines asset renewal and maintenance plans for our networks, conformance to quality and safety standards, how our networks will develop to meet new connection needs and manage customer growth, together with how we intend to monitor, measure and evaluate the performance of our assets, now and into the future.

This AMP is a ten-year forward plan of major work on our asset portfolio to ensure that asset criticality and risks are understood and managed and opportunities are availed. It strongly focuses on the future, particularly as we look towards the impacts of decarbonisation, the increasing reliance on electrification and the growing uptake of electric transportation in our regions, and the need for resilient networks in the face of the effects of climate change.

This AMP reflects how the use of technology to manage the network on a day-to-day basis, improving our low-voltage network visibility, and the growing requirement to manage Distributed Energy Resources as part of the make-up of our future networks, is part of the long-term planning now needed to deliver against the needs of our customers - today and tomorrow.

AMP Network Development Projects

Key Achievements for OtagoNet's Asset Base over the Past 5-10 Years

Over the past 5-10 years, we have remained focused on developing our network to ensure the provision of a resilient, reliable and safe electricity supply for our region.

In 2014, OtagoNet took possession of the Transpower Palmerston Substation and the 110kV lines from Halfway Bush in Dunedin to Palmerston. Transpower's divestment of the lines and substation allowed OtagoNet to reconfigure the network to improve the reliability and security of supply in the area, which serves around 3,400 customers.

Throughout the past ten years, and dating back to the acquisition in 2002, there has been a significant focus on assert replacement and renewal in the OJV region and asset upgrades. This has led to substantial investment in the network by the participants, TPCL and EIL.

In addition, our efforts on the LNL network to support growth in the region remained a constant, making it the network of choice for commercial and residential developers, and their customers. We continued to work with the community, its developers and partners to ensure there is the required electricity infrastructure to meet the region's needs today, whilst planning for the anticipated growth of tomorrow by continuing to co-develop new subdivisions and commercial developments in the region.

OtagoNet's Asset Management Focus for the Next 5-10 Years

The focus of OtagoNet's AMP future programme is on initiatives that will support growth in our regions, together with plans to maintain and improve our networks' safety, efficiency, and reliability.

For the 10-year period reported in this 2024-34 AMP, we are forecasting a total spend of $398M. When compared to the last AMP, key changes include the removal of the major capital project to relocate the Elderlee Street zone substation (Milton) and allowance for Reliability & Resilience projects later in the planning period. Overall, our AMP forecasts reflect the programme of work that we have identified over the next 10-year planning period to mature our asset management capability, support customer growth, and improve our service provision for customers, to include:

- Meeting customer requests for new connections based on historical and future trend analysis across both networks.
- Enabling growth on our Lakeland network through supporting new subdivisions and increased connections – including increased capacity required at Silver Creek, Shotover Country, Northlake and Hikuwai in Wānaka, Wooing Tree in Cromwell and Hanley's Farm subdivisions.

- Upgrading assets across the networks for the continued security of supply and to cater for growth - Frankton Road 22kV extension, Southern Corridor, Quarry Road (Merton) and Blueskin Bay (Waitati) zone substations, Patearoa substation capacity upgrade, Maniototo Road-Lower Gimmerburn 11kV line, and the regulator and line upgrade at Puketoi.
- Improving the efficiency of our networks by replacing and strengthening assets where needed – including 11kV switchgear replacements at Owaka, Palmerston, Milton, Kaitangata, Clinton, North Balclutha, Finegand, Ranfurly and Waihola; and transformer oil containment and seismic strengthening in Ranfurly.
- Quality of supply projects, like improving RMU SCADA and communications for LNL.
- Continued asset renewals and replacements across both networks, including power transformers, relays, circuit breakers and RTUs.
- Routine inspections, testing and maintenance across all assets.
- Safety, environmental, and other projects.

In addition, our AMP reflects provisions for the changes to our electricity system to enable decarbonisation. At OtagoNet, we predict the emergence of new solutions as people embrace new technologies, take control of their energy use, and demand climate change action. Supporting this evolving environment has been an important strategic lever for OtagoNet, which is therefore reflected in our 10-year investment plans.

Our Regulatory Environment

OtagoNet is regulated under the electricity industry framework set by the Commerce Commission. Along with defined regulatory reporting requirements, there are commercial restrictions and penalties as a non-exempt network.

The regulatory period, from 2020-2025 (DPP3), has been extremely challenging from an asset owner perspective. The allowable returns from the Commerce Commission have not been sufficient to adequately fund the network as anticipated. Since the returns were set for DPP3, there have been significant cost pressures impacting the business, such as equipment and material costs, international shipping and freight costs, increased compliance costs (e.g. traffic management regulations), significant increases in the cost of debt funding, and a very tight labour market. None of these factors were adequately provided for in the DPP3 returns. As such, OtagoNet has deferred some asset replacement activity from DPP3 to DPP4 (2025-2030) in order to be able to adequately fund this asset replacement and renewal expenditure. This accounts, in part, for the significant increase in capital expenditure from 2025 onwards. These deferral decisions have been made whilst ensuring workplace and public safety, network security and asset health is managed, however there is an expectation that the allowable returns from DPP4 onwards will be more sustainable.

For OtagoNet, working within the revenue cap and expenditure allowances provided by the Commerce Commission over the current DPP3 period has made it increasingly difficult for the industry to respond with the flexibility needed to enable an equitable transition for electrification and decarbonisation of the NZ economy.

PowerNet, as the network manager for OtagoNet, is in a unique position with its management of three networks (one exempt and two non-exempt), as it can compare the differences this creates and better understand the challenges for non-exempt networks like OtagoNet.

There is now clear evidence that the regulatory framework does not provide the required flexibility to meet the challenges and opportunities that electrification and decarbonisation of the New Zealand economy will present. PowerNet continues to share its concerns with industry stakeholders and has been able to compare and contrast the flexibility and ability to respond to customers' needs on its exempt network, verses non-exempt networks. Changes are required to the regulatory framework in order to ensure an equitable transition to a net-carbon zero economy.

Developing the right regulatory settings for a changing environment is critical to a robust level of service and flexibility for changing customer needs, and OtagoNet looks forward to ongoing collaboration and engagement by PowerNet with the regulator and other stakeholders.

In Conclusion

OtagoNet's Asset Management Plan (AMP) outlines how network assets will be managed and developed to provide a safe, efficient, and reliable electricity supply and service to OJV's customers in rural and coastal Otago, as well as the communities serviced by our Lakeland network, over the next 10 years. It sets out planned capital and maintenance expenditure on these networks from 2024-2034 and also reflects the continued focus on customers and developers to better understand their plans to ensure this AMP caters to, and supports, the growth projections of our regions.

As outlined in the Executive Summary which follows, this AMP focuses on ensuring the OtagoNet network continues to deliver for customers through a dedicated investment programme that includes information on performance and service targets, justification for planned investments, together with the risks and how those will be mitigated through careful and considered asset management practices over the next ten years.

OtagoNet are committed to continuing to provide a network that meets the needs of communities, and welcome ongoing input from stakeholders to ensure the assets and services provided are fit for purpose - now and into the future.

Abbreviations, Acronyms and Definitions

There have been no changes to this section.

ABC	Aerial Bundled Conductor
ABP	Annual Business Plan
ABS	Air Break Switch
ALARP	As Low as Reasonably Practicable
AMIS	Asset Management Information System
AMP	Asset Management Plan
AWP	Annual Works Program
CAPEX	Capital Expenditure
CBD	Central Business District
CCTO	Council Controlled Trading Organisation
CES	Customer Engagement Survey
ComCom	Commerce Commission
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DIN	Deutsches Institut für Normung (the German Institute for Standardisation)
DPP3	Default Price Path 3
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association
EIL	Electricity Invercargill Limited
ENA	Electricity Network Association
GIS	Geographic Information System
GPS	Global Positioning System
GXP	Grid Exit Point
HILP	High Impact Low Probability
HRC	High Rupture Capacity
HVBT	High Voltage Busbar Insulation Tape
ICP	Interconnection Point
IED	Intelligent Electronic Device
IoT	Internet of Things
KPI	Key Performance Indicator
LNL	Lakeland Network Limited
LSI	Lower South Island
LV	Low Voltage
MAR	Maximum Allowable Revenue

MBIE	Ministry of Business, Innovation and Employment
MD	Maximum Demand
MDI	Maximum Demand Indicator
MV	Medium Voltage
NEM	Network Equipment Movement
NER	Neutral Earthing Resistor
O&M	Operations and Maintenance / Operate and Maintain
ODV	Optimised Deprival Valuation
OHUG	Overhead to Underground
OJV	OtagoNet Joint Venture
OPEX	Operating Expenditure
PILC	Paper Insulated Lead Covered
PNL	PowerNet Limited
RCP	Regulatory Control Period
RMU	Ring Main Unit
ROI	Return on Investment
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SLT	Senior Leadership Team
SWHT	Southland Warm Homes Trust
TCOL	Tap Change on Load
TOU	Time of Use
TPCL	The Power Company Limited
TPM	Transmission Pricing Methodology
UILP	Utilities Industry Liability Programme
VRR	Voltage Regulating Relay
XLPE	Cross-Linked Polyethylene

Commerce Commission (ComCom) means the agency responsible for enforcing laws relating to competition, fair trading, and consumer credit contracts, and has regulatory responsibilities in the electricity lines, gas pipelines, telecommunications, dairy and airport sectors.

Customers means the entities connected to the local lines company, which can be households or businesses. Most customers do not have a direct relationship with their local lines company. Rather, they will engage with an electricity retailer to which they pay their bill.

DPP3 means the price-quality standards that regulated EDBs have to comply with during the regulatory time period 1 April 2020 – 31 March 2025 as set by ComCom

Executive Summary

Introduction

The introductory section focuses on planning assumptions and implications. Planning is based on the expectation that the most likely scenario will occur, except for ongoing but sporadic (typically reactive) work. This philosophy is used to minimise variation to financial performance targets. The standard life of assets is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, economic life, and work efficiency.

The potential variation factor that specifically influences this AMP is the impact of the war in Ukraine, which is currently mostly felt through the increase in operating cost caused by rising fuel prices. The worldwide increase in the cost of energy will eventually flow through to equipment and equipment transport prices.

This section changed from:

The introductory section in the main document describes the process to prepare the annual asset management plan updates. The alignment with the Annual Works Program (AWP) is outlined and the role-players that participate in the asset management planning processes are portrayed. The participation processes are related to:

- Management and operations' participation
- Governance participation; and
- Post disclosure communication

Planning assumptions and implications are described. Planning is based on the expectation that the most likely scenario will occur, except for ongoing but sporadic (typically reactive) work. This philosophy is used to minimise variation to financial performance targets. The standard life of assets is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, economic life, and work efficiency.

The potential variation factors that specifically influence this AMP are the residual impact of the Covid 19 pandemic and the impact of the war in Ukraine, particularly on fuel prices.

Most challenges related to Covid-19 are being addressed, but there are cost and project schedule implications, in particular delivery times for electrical equipment sourced overseas.

The impact of the war in the Ukraine is currently mostly felt through the increase in operating cost caused by rising fuel prices, but the worldwide increase in the cost of energy will eventually flow through to equipment and equipment transport prices.

The OJV Business Environment

There has been no change in the OJV business environment.

The OJV Business Environment remains as follows:

OJV's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of various stakeholders while recognising the need to work within constraints imposed by both stakeholders and wider issues that affect asset management. OJV's business goals are driven by meeting shareholders' and customers' expectations. The context for business operations is also shaped by drivers ranging from governmental and regulatory strategies to natural events such as the unpredictability of weather.

Key corporate drivers from OJV's Strategic Plan are incorporated in the AMP and the guiding principles for OJV's asset management strategy are described in Section 2. OJV's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in the next figure.

Table 1: Corporate and Asset Management Strategy Linkages

Corporate Strategies

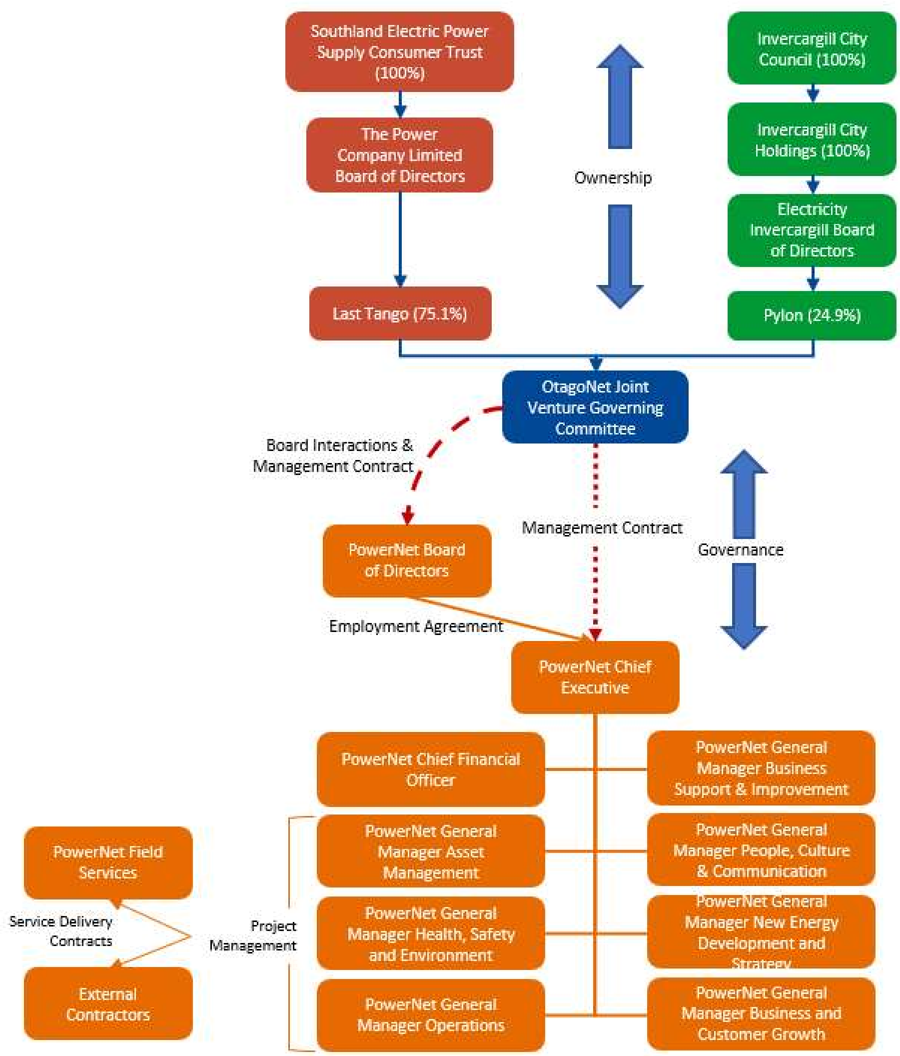
- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
No material deterioration in the condition or performance of the networks	✓	✓			✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

OJV's commercial goal is to deliver a stream of sustainable earnings to Invercargill City Holdings. This creates a primary driver for OJV and formal accountabilities to the shareholder are in place for financial and network performance. However, there are various role-players in OJV's business and the management of role-players' expectations and how conflicting interests are dealt with is described in detail in this section of the AMP.

Section 2 also details the planning processes and related documents, the organisational structure and accountabilities, as well as the extent of the supply area and quality of service. Business planning take place within the overall framework of Quality, Occupational Health and Safety and Asset Management. An overview of the governance and management accountabilities is presented in the next figure.

Figure 1: Governance and Management Accountabilities



The Network and Asset Base

Excepting residential developments, incremental growth and business-as-usual network renewal, the network and assets are largely unchanged from the 2023-33 AMP.

The 2023-33 AMP describes the Network and Asset Base as follows:

OJV's service area includes three geographically separate areas: the rural Otago area supplied by the Balclutha, Halfway Bush and Naseby GXPs, the Frankton area supplied by Frankton GXP and small embedded networks north-east of Wanaka and on the north side of Cromwell. The network also takes energy from three embedded generators: the Mount Stuart wind farm, and the Paerau and Falls Dam hydro schemes. In total OJV supplies 18,881 residential, commercial, and industrial customers across all network areas.

The rural Otago sections of network are predominantly overhead due to the low density of customer connections making undergrounding impractical. Industrial loads make up a significant proportion of the load, in particular the gold mine at Macraes Flat which consumes approximately one third of OJV's electricity volume. The remaining load is predominantly farming along with some domestic load concentrated in regional towns.

OJV owns and operates 32 zone substations with a 66/33 kV interconnecting station; there are also nine sites on the network where customers are connected without the use of distribution voltage. The distribution network is predominantly radial in rural areas due to the mountainous topography and sparsity of connections; distribution is mostly 11 kV overhead three phase and single phase, although 11 kV and 22 kV Single Wire Earth Return circuits are used on the fringes of the network.

The Frankton Hayes network is entirely underground and supplies a proportion of the newer residential and commercial developments in the area. It is predominantly meshed with extensive use of 22 kV cable.

The Frankton area network is relatively new with the first assets being installed in 2003. However the overhead line assets that form the backbone of the Otago rural network are relatively old, and the 2022 Information Disclosure shows an average 61% of weighted average expected asset life remaining for subtransmission lines and 54% for distribution/LV lines. Most of these assets are in reasonable condition, but significant line replacement work will continue to be required during the planning period.

The following network aspects are described in detail in the AMP (Section 3):

- Network Configuration.
- Load Characteristics.
- Energy and Demand Characteristics.

Areas on the network have differing load densities and rates of growth which are more likely to influence asset management planning. Growth rates on the network are relatively low and connections for large new customers are unpredictable so planning for this can be challenging. There are not any individual customers considered large enough to have any significant impact on network operations or asset management planning other than ensuring that adequate supply capacity is maintained.

Risk Management

The following additional significant risks (company-wide) were identified and are described in Section 4 of the AMP update:

- Cyber Security - Events were detected but intentional damage was prevented by the IT security systems. Notable is the increase in electronic security events.

Risks related to asset management are provided in Section 4. The projects and actions described in this AMP are intended to mitigate these risks.

The biggest impacts are due to:

- Unavailability of critical spares.
- Loss of key critical service provider.

Equipment risks to the electricity system are related to the following assets or network.

- Oil Filled RMUs.
- Other Systemic Issues.

The 2023-33 AMP describes OJV's Risk Management as follows:

Risk is defined as any potential but uncertain occurrence that may impact on OJV's ability to achieve its objectives and ultimately the value of its business. OJV is exposed to a wide range of risks and risk management techniques are used to keep risk within acceptable levels. Risks can often not be fully eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. In Section 4 OJV's risk exposures, the management of the exposures and activities to reinstate service levels should disaster strike are described.

The following significant risks (company-wide) were identified and are described in Section 4 of the AMP:

- COVID-19 pandemic - Loss of key service providers; business operations disrupted; cost and schedule overruns.
- Cyber Security - Events were detected but intentional damage was prevented by the IT security systems. Notable is the increase in electronic security events.

Risks related to asset management are provided in the next table (details on these risks are provided in Section 4). The projects and actions described in this AMP are intended to mitigate these risks.

Table 2: Asset Management Risks

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure; ineffective maintenance; ineffective fleet plans; budget constraints; lack of future network planning	Reliability Collapse/fall causing harm Voltage causes harm	Treat	Implement AMMAT improvements; resourcing; fleet plans; business management framework; information systems
Network Performance	**Operational systems failure due to breakdown in telecommunications**	SCADA communications has one centralised communications point that all information is passed through.	Loss of SCADA would require resorting to manual oversight of the networks	Treat	3 yr. Project underway to provide further links - due for completion 2023
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism Reputation	Damage to equipment Damage to systems/data Change in network configuration SAIDI/SAIFI Impacts Reputation Impacts	Treat	Programme to replace locks and improve security implemented
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision)	Objection of landowner where line or cable is over boundary Demand for removal of assets and/or legal action	Tolerate	
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Limited staff, facilities or equipment available; localised or wide spread loss of the ability to supply power	Treat	Completion of seismic strengthening Design of networks to avoid high event probability areas
Operational Performance	**Potential liability for private lines and connections**	Regulatory change Poor historical process/records Fatality with some repercussion for PowerNet - legal advice has not been tested in court	Obligation to maintain assets vested in the network	Treat	Association to ENA and MBIE: *(currently reviewing situation with aim of a consistent industry solution)*

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact events causing high spares usage Supply chain disruptions	Inability to supply	Treat	Review critical spares process Stocktake critical spares Record spares in Maximo Education of staff on spares process and locations Comparison of existing assets to critical spares (and update with changes to the network) Supplier relationships; alternative suppliers; leverage Corys' international partnerships
Operational Performance	**Loss of key critical service provider**	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Inability to build or maintain assets Unable to service existing contracts	Treat	Improved identification of critical suppliers Identify alternative suppliers Diversify the workforce Internalise and grow internal workforce Diversify into new markets (create a larger pool)
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Delayed or limited provision of power to consumers Loss of ability to provide power to customers for extended periods	Treat	Develop improved contingency plans for network events
Health & Safety	**Public encountering live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Serious injury or fatality Prosecution under H&S Act	Treat	Asset Lifecycle risk management Increase public awareness through various media Asset design and operation
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Breaches of environmental legislation Cost of rehabilitation	Treat	Design standards take environmental risk into account Asset do not contain hazardous substances or hazardous substances are controlled

Service Levels

There has been no change in service levels.

The Service Levels remain as follows:

A broad range of service levels are created for OJV's stakeholders, ranging from those paid for (for their own benefit) by connected customers such as capacity, continuity and restoration to those subsidised by connected customers such as ground clearances, earthing, absence of electrical interference, compliance with the District Plan and submitting regulatory disclosures.

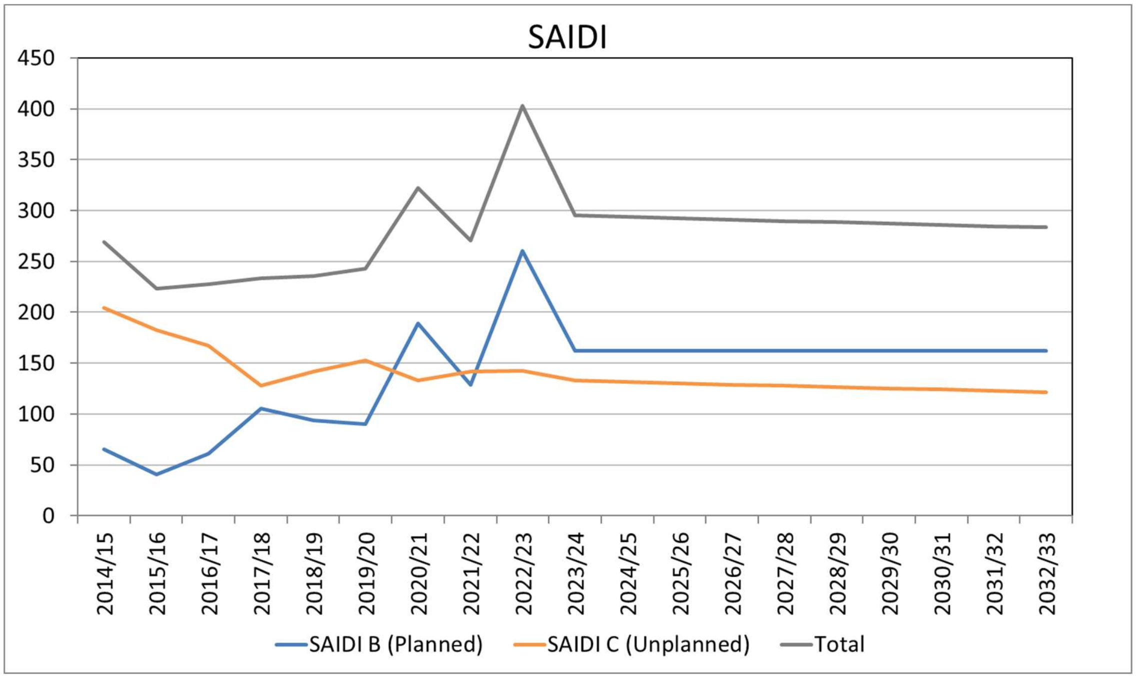
This Section in the AMP describes how OJV sets its various service levels according to the safety, viability, quality, compliance, and price objectives that are most important to stakeholders. It details how well OJV is meeting these objectives and what trade-offs exist between differing stakeholders. Considerations include the desire for Return on Investment (ROI) versus desire for low price with good reliability, safety as priority versus acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

Safety is OJV's top priority and is a primary consideration in the AMP. However, safety has always been a key consideration in network design and the residual risk that can be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Safety KPIs are not presented in the AMP but are available to interested parties upon request.

The section on customer-oriented service levels describes customer surveys, primary and secondary customer service levels, as well as other service levels. The section also details the following:

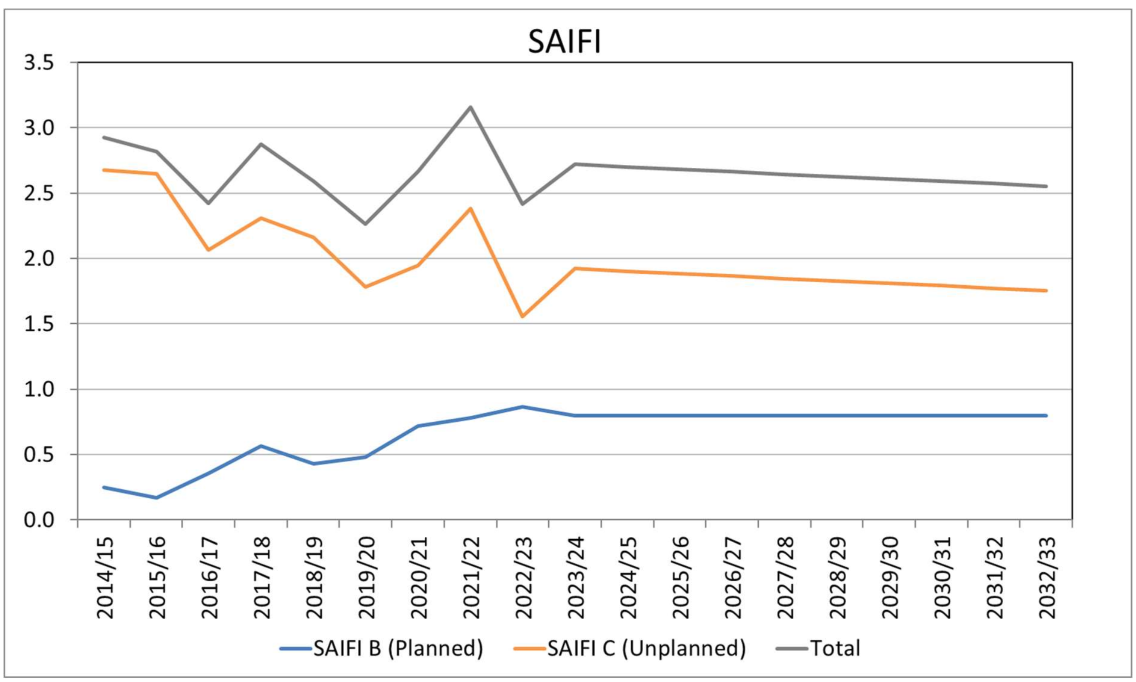
- regulatory service levels
- service level justification, and
- service level targets.

Figure 2: Historical and predicted SAIDI



Customers on average can expect to be without electricity for around 5 hours each year.

Figure 3: Historical and predicted SAIFI



Customers will on average experience an interruption less than three times each year.

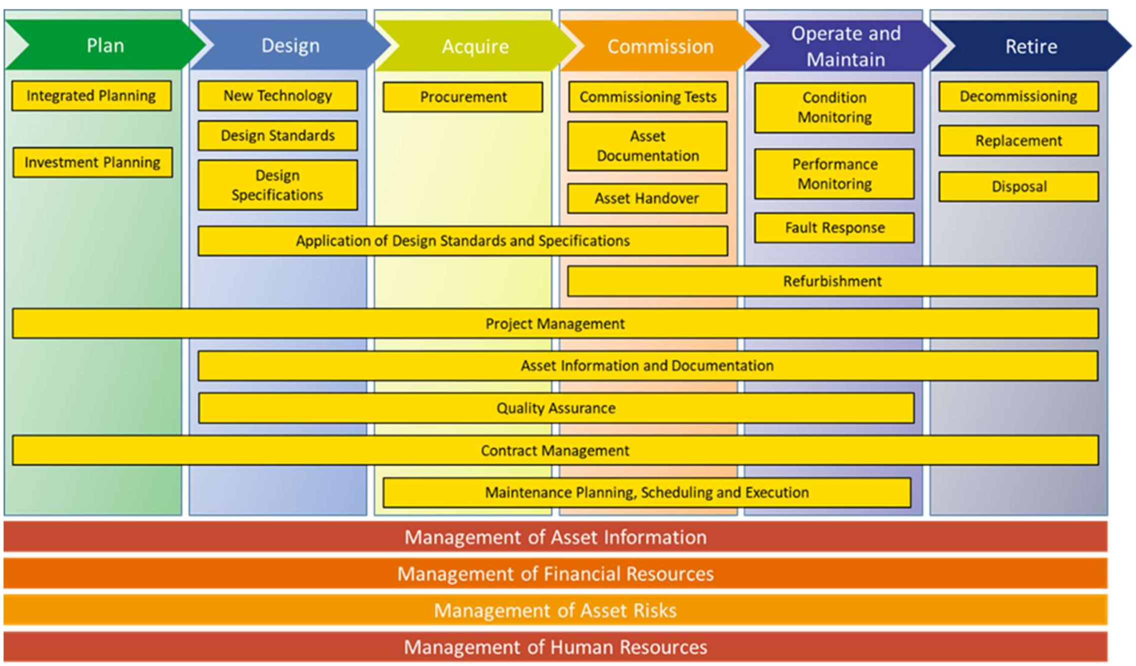
Asset Management Strategy

OJV's Asset Management Strategy is based on PowerNet's asset management model (focusing on a lifecycle management approach). The defined strategic objectives and initiatives are aligned with the relevant stakeholder' business plans. These are aimed at achieving continuous business improvements through balancing risk, performance, and cost.

The model has not changed from the 2023-33 AMP and can be described as follows:

The strategy is structured to address the main activities and challenges faced in each lifecycle stage as well as the support processes. It defines objectives for each activity and recommends initiatives to achieve the stated objectives. In each case, responsibilities are defined and realistic timeframes are suggested. Figure 4 charts the various asset lifecycle stages and support processes that cut across the entire lifecycle.

Figure 4: Lifecycle Model for Asset Management



Details for each of the asset lifecycle stages are described in Section 6 of the AMP. In addition, the following lifecycle support processes are explained:

- Management of Asset Risks.
- Management of Asset Information.
- Management of Human Resources.

- Management of Financial Resources.

Asset management requires processes for defining and capturing as built, maintenance and renewal unit costs and methods for the valuation and depreciation of its assets. The present normal business challenges include the management of human and financial resources. The strategic objective for the management of human resources is that:

> *the necessary resources and skills to plan, acquire, operate and maintain the assets that PowerNet manage, be attracted, developed, retained and be available when required.*

Financial resources are required to manage assets efficiently over their entire lifecycle. The major strategic objective for the management of financial resources is that:

> *the necessary resources to plan, acquire, manage, operate, and maintain assets that PowerNet manage shall be developed, and finances made available when required.*

Capital Expenditure

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets. CAPEX is categorised according to the following ComCom requirements.

- Consumer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

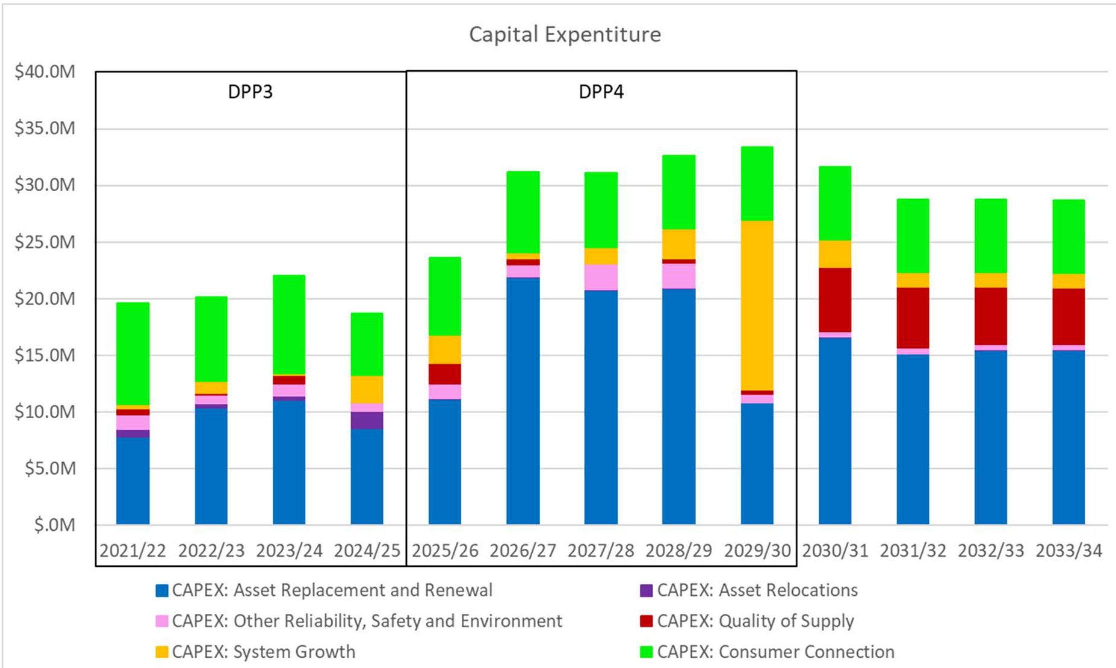
The proposed Capital Expenditure is reflected in the next table and figure.

Table 3: 2024-34 Update Proposed Capital Expenditure ($000)

Category	DPP3		DPP4					DPP5			
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
CAPEX: Consumer Connection	8,569	5,413	6,831	7,132	6,613	6,410	6,428	6,434	6,410	6,410	6,410
CAPEX: System Growth	203	2,397	2,473	502	1,387	2,712	14,944	2,432	1,295	1,295	1,295
CAPEX: Asset Replacement and Renewal	11,105	8,585	11,161	21,916	20,785	20,924	10,830	16,612	15,148	15,462	15,462
CAPEX: Asset Relocations	338	1,471	38	38	38	38	38	38	38	38	38

CAPEX: Quality of Supply	761	13	1,794	505	44	357	357	5,671	5,357	5,044	5,013
CAPEX: Other Reliability, Safety and Environment	1,040	802	1,338	1,097	2,239	2,197	745	486	486	486	486
Total Network CAPEX	**22,016**	**18,680**	**23,636**	**31,191**	**31,107**	**32,639**	**33,341**	**31,673**	**28,735**	**28,735**	**28,705**
CAPEX: Non-Network Assets	-	-	-	-	-	-	-	-	-	-	-

Figure 5: 2024-34 Update Capital Expenditure per ComCom categories



The Capital Expenditure as proposed in the 2023-33 AMP was:

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets. CAPEX is categorised according to the following ComCom requirements.

- Consumer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

The following risks are relevant to capital expenditure are detailed in Section 7 of the AMP.

- Planning Phase Risks.
- Network Development Drivers.
- Current Demand Profiles.
- Demand History.

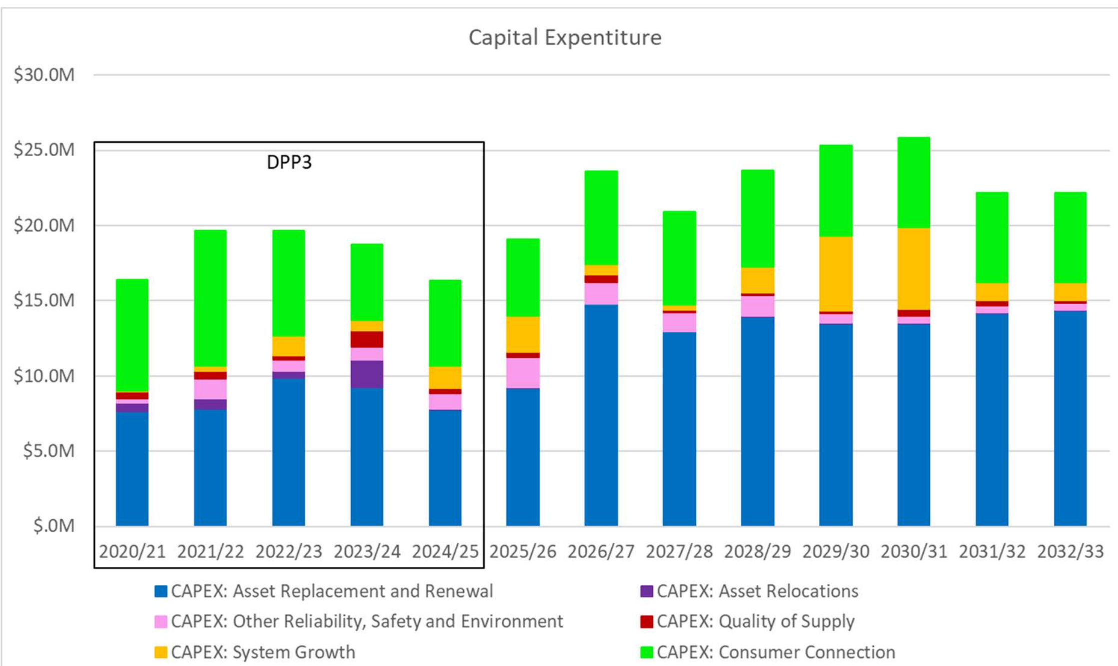
- Public and employee safety.

The proposed Capital Expenditure is reflected in the next table and figure.

Table 4: Proposed Capital Expenditure ($000)

Category	DPP3			DPP4					DPP5		
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
CAPEX: Consumer Connection	6,966	5,020	5,661	5,084	6,195	6,176	6,372	5,997	5,997	5,972	5,972
CAPEX: System Growth	1,309	693	1,511	2,408	684	362	1,737	5,013	5,387	1,210	1,210
CAPEX: Asset Replacement and Renewal	9,870	9,246	7,770	9,218	14,776	12,940	13,948	13,485	13,501	14,184	14,338
CAPEX: Asset Relocations	484	1,839	36	36	36	36	36	36	36	36	36
CAPEX: Quality of Supply	306	1,051	348	337	486	179	179	179	486	339	185
CAPEX: Other Reliability, Safety and Environment	718	881	1,020	2,005	1,427	1,249	1,383	628	455	455	455
Total Network CAPEX	**19,652**	**18,730**	**16,346**	**19,088**	**23,604**	**20,941**	**23,655**	**25,338**	**25,862**	**22,196**	**22,196**
CAPEX: Non-Network Assets	41	27	-	-	-	-	-	-	-	-	-

Figure 6: Capital Expenditure per ComCom categories



Operating Expenditure

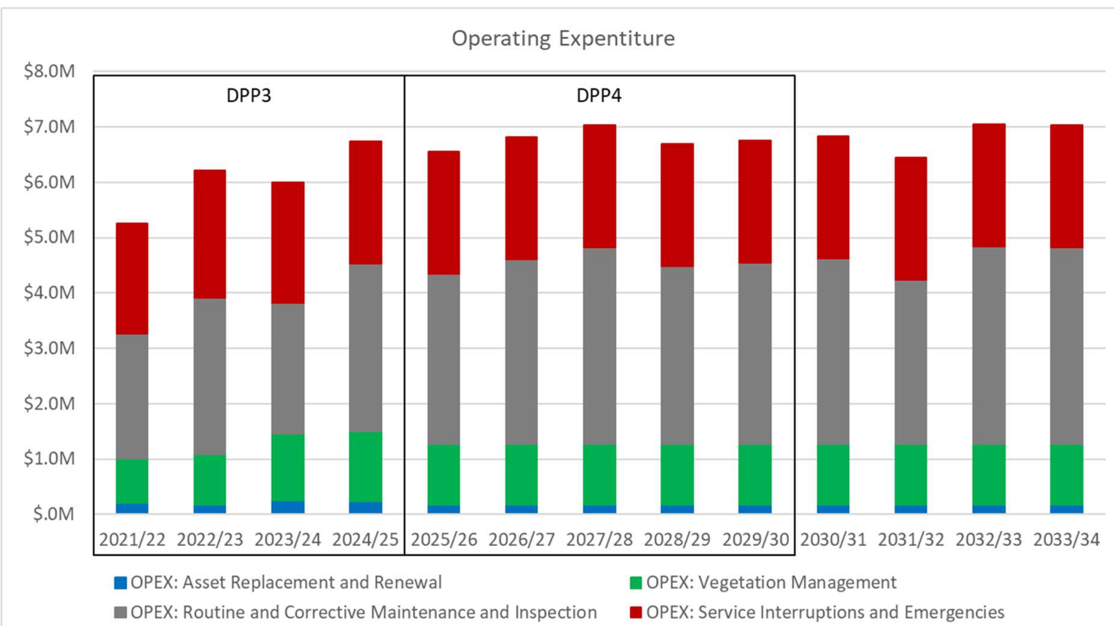
Operating Expenditure (OPEX) is required to operate and maintain OJV's networks. OPEX is categorised according to the following ComCom requirements.

- Asset Replacement and Renewal.
- Vegetation Management.
- Routine and Corrective Maintenance and Inspection.
- Service Interruptions and Emergencies.
- The proposed Operating Expenditure is reflected in the next table and figure.

Table 5: 2024-34 Update Proposed Operating Expenditure ($000)

Category	DPP3		DPP4					DPP5			
	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
OPEX: Asset Replacement and Renewal	248	244	178	178	178	178	178	178	178	178	178
OPEX: Vegetation Management	1,213	1,265	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
OPEX: Routine and Corrective Maintenance and Inspection	2,352	3,020	3,082	3,345	3,564	3,221	3,287	3,361	2,973	3,572	3,564
OPEX: Service Interruptions and Emergencies	2,188	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208
Total Network OPEX	**6,001**	**6,737**	**6,556**	**6,819**	**7,038**	**6,695**	**6,761**	**6,835**	**6,447**	**7,046**	**7,038**

Figure 7: 2024-34 Update Operating Expenditure per ComCom categories



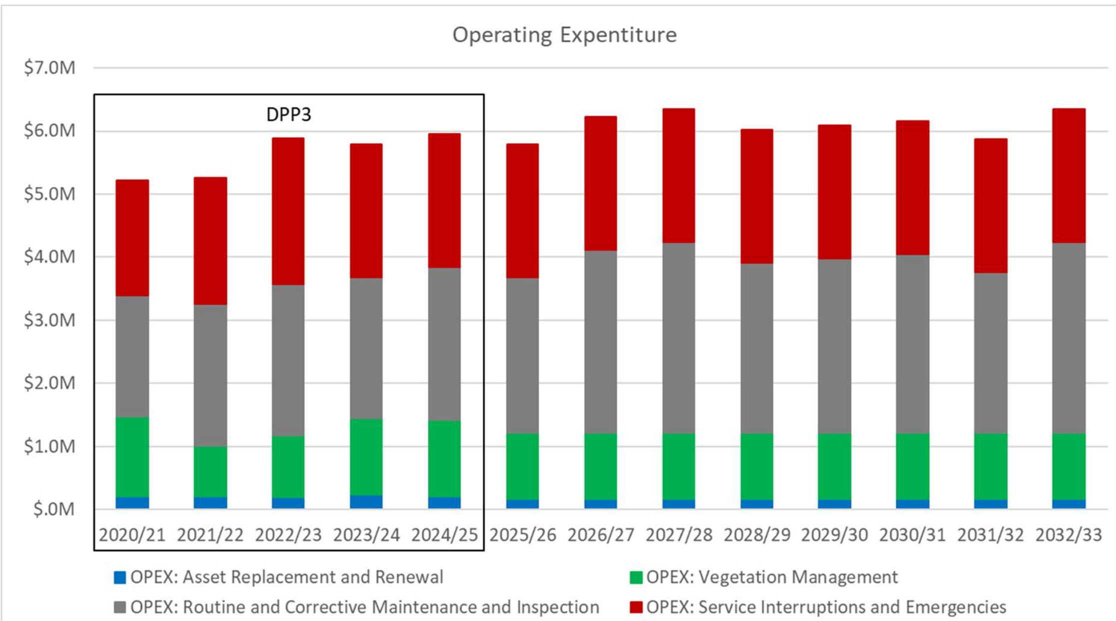
The Operating Expenditure as proposed in the 2023-33 AMP was:

Table 6: Proposed Operating Expenditure ($000)

Category	DPP3			DPP4				DPP5		
	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33

OPEX: Asset Replacement and Renewal	198	229	209	167	167	167	167	167	167	167	167
OPEX: Vegetation Management	978	1,213	1,213	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042
OPEX: Routine and Corrective Maintenance and Inspection	2,400	2,242	2,418	2,477	2,908	3,030	2,707	2,770	2,836	2,558	3,031
OPEX: Service Interruptions and Emergencies	2,305	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Total Network OPEX	5,880	5,792	5,948	5,794	6,225	6,347	6,024	6,087	6,153	5,876	6,348

Figure 8: Operating Expenditure per ComCom categories



Execution Capacity

It remains problematic to obtain the required numbers of appropriately skilled resources. This applies to all levels of staff, but particularly to technical and field staff.

This was described in the 2023-33 AMP:

The requirements to execute the AMP successfully centres around the following enablers:

- People Culture and Leadership.
- Funding the Business.
- Managing the data and information in our systems.

The way we determine the work execution requirements is by determining the man hours and other resources required to execute each item of work or project. This information is captured in the Fleet Plans. The individual items of work is costed and consolidated into the Annual Works Programme. The planned Works Programme is analysed to determine the overall resource requirements for the work execution. Adjustments are then made based on resource availability. These adjustments may be delaying work until resources become available, using contractors or, if there is a long-term resource requirement, appointing additional staff or procuring the required plant or equipment.

There are the normal business challenges relating to skilled resources. This applies to all levels of staff, but particularly to technical and field staff. These challenges are being managed by PowerNet and they have strategies in place relating to this.

OJV's revenue comes primarily from retailers who pay for the conveyance of energy over OJV's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the Commerce Commission.

Expenditure is incurred to maintain the asset value of and to expand or augment the network to meet customer demands. In addition, there is a Management Agreement in place between PowerNet and EIL, where a management is fee paid to PowerNet for managing the networks on behalf of OJV.

There are a variety of information management tools which capture asset data and can be used to create summary information from the data. Based on this foundation, OJV has sufficient knowledge about almost all the assets; their location, what they are made of, how old they are in general and their performance.

Evaluation of Performance

In 2022/23 capital expenditure was 27% above budget and operating expenditure was 21% higher than planned.

Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital and operation expenditure costs.

Network reliability was within the Commerce Commission limits.

Benchmarking service levels against other electricity distribution businesses indicates OJV is performing well on behalf of its stakeholders.

The equivalent figures in the 2023-33 AMP were:

In 2021/22 capital expenditure was 27% higher than expected and operating expenditure was 11% higher than planned.

Capital over expenditure related to several factors: predominantly increased customer driven demand for subdivision reticulation, higher spending on distribution and LV lines' renewal than planned, and unforeseen works relocating and undergounding power lines for third parties.

Over expenditure of operating funds related mainly to a larger amount of distribution faults than allowed for, offset somewhat by lower expenditure on asset replacement and renewal maintenance activity.

Customer satisfaction was canvased through online and telephone surveys, and face to face interactions. The level of satisfaction was good, with five out of seven secondary service metrics ranked above the target level.

Network reliability decreased mainly due to faults caused by defective equipment and adverse weather, and increased duration of planned outages.

Asset Management Maturity was assessed and in most areas the scores improved. The exceptions related to training, awareness and competence; information management; and use and maintenance of asset risk information. Initiatives for improvement in these and other asset management areas are in progress or have been completed in the drive towards ISO 55001 certification.

Benchmarking service levels against other electricity distribution businesses indicates OJV is performing well on behalf of its stakeholders.

1 Introduction

1.3 2024-34 Update Assumptions

The assumptions as per the 2023-33 AMP are still mostly valid. The exceptions are shown in Table 7: Assumptions and Implications. The assumption changes and potential impacts are discussed further in section 4 Risk Management

Table 7: 2024-34 Update Assumptions and Implications

Assumption	Discussion & Implications
Change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost and duration of works. Examples are more onerous traffic control measures required at worksites on public roads and the Tree Regulations.
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury, where specific forecasts unavailable)	Covid-19 has led to significant equipment and material cost increases (almost 20% weighted average). This has affected the amount of work that could be executed within the available funding. Deviation from expected material, labour, overhead input costs, has resulted in increased costs to works programmes. The projected treatment of network constraints changed, depending on the specific changes to each input cost factor. The assumption is that these cost increases will stabilise and become more predictable.
Decarbonisation of heating will cause localised changes over the next 5 years, necessitating local network upgrades.	The decarbonisation initiatives in OJV are limited mostly to the conversion of space heating systems currently using coal fired boilers to heat water which is then circulated through radiators. These systems are being upgraded either through electrification of the boilers or by installing heat pumps. This may trigger localised upgrades of transformers and MV and LV distribution cables earlier than currently envisaged. The cost of these upgrades are generally carried by the customer.

The related sections in the 2023-33 AMP read as follows:

1.1 Asset Management Plan and Annual Works Program

OtagoNet Joint Venture (OJV) is the disclosing entity for the electricity lines businesses that conveys electricity to much of rural Otago, areas of Frankton and part of Wanaka and Cromwell, supplying approximately 18,900 customers.

OJV's Asset Management Plan (AMP) provides an internal governance and asset management framework for OJV's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination as amended on 25 November 2022 for the ten-year planning period from 1 April 2023 to 31 March 2033.

The purpose of OJV's Asset Management Plan (AMP) can be summarised as follows.

The plan:

- Documents the nature, extent, age, utilisation, condition, performance and value of the infrastructure.
- Identifies existing and proposed levels of service to be achieved over a five year period, as well as any expected changes in demand.
- Identifies the life-cycle management needs (development, renewal, operations and maintenance and any disposal) over the five year period.
- Assesses capital and operational budget needs and funding implications; and
- Assesses the prevailing infrastructure asset management practice and identifies further improvements.

Other key asset management documents for OJV are.

- The Annual Works Programme (AWP) detailing the capital and operation expenditure forecasts for the next ten years being produced as part of the development of the AMP.
- The Annual Business Plan (ABP) which consolidates the first three years of the AMP along with any recent strategic, commercial, asset or operational issues from the wider business. The ABP defines the priorities and actions for the year ahead. It also forms the principal accountability mechanism between OJV's Governing Committee (Board) and its shareholders.
- The first draft of the Asset Management Plan (AMP) is usually created by November each year and is circulated amongst management for review and comment. The Annual Works Program (AWP) is developed concurrently as part of the AMP process and has generally been through several revisions by the time it is circulated with the first draft AMP.
- Customer perceptions and expectations are compiled from surveys and customer consultations. These results are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate are incorporated into the AMP and AWP as necessary. The survey used for this document is the July 2022 survey.

1.2 AMP Communication and Participation Processes

The role-players that participate in the asset management planning processes and to whom information is communicated, are described in the following paragraphs.

Management and Operations Participation

The planning team is in regular contact (throughout the year) with those responsible for implementing the current AWP. Progress is monitored and variations supervised as they arise with large capital projects. These are addressed in formal monthly review meetings. Any changes are consolidated into the initial AWP revision. Further revisions are developed in consultation with management, project managers and field staff who will be involved in the implementation processes.

Through this consultation the costs and resources for the desired work in the year ahead are estimated. The process tends to be iterative with a level of trade-off reached between what is considered an optimal level of works against realistic expectations of the work force available. Should the required work exceed internal resources, contractors are utilised. “Smoothing” of the year to year works variations is utilised to keep a relatively constant and manageable work stream for both internal and external workforce resources; however longer-term variations need to be met by adjusting the resources available. Additionally, this process tends to be one of moving goal posts as variations generally need to be accounted for up until the information disclosure date.

Governance Participation

The initial consolidated AWP is submitted to the OJV Board supported by a presentation. Any business cases required for large capital projects or other papers covering any non-business as usual projects are submitted in advance and will be included in the AWP presentation. After their initial review the Board may request clarifications or changes which are then incorporated into the AWP. These changes reflect both asset management and commercial aspects, and always recognise the need to address any identified health and safety related issues as the highest priority. Any recommended changes to the wider AMP that the Board may need to consider, for example strategy updates, may be presented at this stage for review.

The AMP is then updated to reflect changes to the AWP (development planning and lifecycle management) incorporating any other changes required by management before being submitted in full to the OJV Board for review in February. The Board may request further changes to be completed before giving final approval for disclosure at the end of March.

Post Disclosure Communication

Once the AMP has been finalised and publicly disclosed, project scopes are produced for non-routine projects that will be initiated in the next year. These scopes are passed to the relevant project managers to ensure that sufficient detail has been provided for each project in the AWP to proceed in line with the planner’s expectation.

An initial communication meeting is held with internal field staff and key contractors to highlight the body of work for the year ahead, especially for large or crucial projects. Future years as set out in the AMP are also presented to assist contractors in preparing their resources and their ability to compete for any tendered work in the short to medium term.

Planners (Network Engineers) are in contact with the project managers throughout the year to monitor execution of the AWP and ensure agreement on any significant variations as design and implementation progresses.

Progress Evaluation

The progress against the AMP objectives is measured as follows:

- Monthly Major Project review meetings to assess progress on significant projects.

- Monthly Business Review meetings to assess business performance.
- Quarterly Management reviews to assess the effectiveness of the various management systems as well the integrated Business Management System.
- Monthly Safety meetings per depot and a monthly Safety Leaders meeting.

Outcomes of these meetings are presented to the Board in the monthly Chief Executive report and Management report. This reporting contains information on safety performance, network performance and asset health for specific asset classes identified by the Board.

1.3 Assumptions

In our planning we assume that the scenario considered most likely will eventuate, except for ongoing but sporadic (typically reactive) work, where budgets reflect a longer-term average. This philosophy is used to minimise variation to performance targets (especially financial) including average performance over the short to medium term. Exceptions are made where the consequences of this assumption are asymmetric – for example building additional capacity early results in a slight overinvestment, whereas building additional capacity too late may have much greater consequences such as equipment damage or inability to supply customer load.

The standard life of assets is based on the Commerce Commission's Optimised Deprival Valuation (ODV) asset life, with actual replacement done based on condition, and economic life and work efficiency. Equipment housed indoors will often exceed ODV life, whereas in the harsh coastal environment assets tend to have a shorter life.

No significant change in present regulation other than the recent default price-quality path is anticipated. Any changes are likely to add additional cost.

Project costs and timeframes are estimated based on previous experience and anticipated resourcing. Other than the disclosure schedules included in Annexure 3, all figures are represented as 2023 dollars and assume no significant variation in exchange rates (where applicable).

Table 8: Assumptions and Implications

Assumption	Discussion & Implications
Demand growth tracks close to projected rates The drivers of future demand described are as per the most likely scenario and this section discusses how OJV manages the risk of different patterns of growth eventuating.	Actual future demands may depart significantly from forecasts. Prediction of demand growth based on "ground-up" analysis is uncertain, due to limited visibility of many variables. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in OJV's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.

Assumption	Discussion & Implications
Distributed generation is expected to have little coincidence with network peak demand, and therefore will have little impact on network configuration within the ten-year planning horizon	Increased injection of generation, especially during periods of low demand, could create voltage issues. Increased connection requests for distributed generation will require increased resourcing to analyse potential issues arising from connection (particularly safety and voltage)
Electric vehicle adoption rate within forecast, and that consumers will respond well to price signals such that vehicle charging occurs off-peak	Potential to have large impact on network demand with sufficient adoption. If consumers do not respond well to price signals, electric vehicle charging may exacerbate peak demand, triggering greater investment. This effect will be greatest on the LV network where issues are more likely due to lower diversity and are more difficult to predict.
Service life of assets, tend towards expected life for the asset type and operating environment	Long term projected service life of asset fleets is based on expected service life for the asset type, operating environment, expected duty, and maintenance practices. Actual replacement and maintenance works are programmed on a near term basis; and are driven by condition and safety for the specific asset. More benign operating environment may increase service life. Investment may be deferred if condition analysis provides reasonable certainty of extended asset life. Harsher environment and/or greater operating duty tends to shorten asset life, requiring consideration for earlier replacement.
No material deviation from historical failure rates	Deterioration of asset reliability compared to expected failure rates, would require accelerated asset replacement (to maintain service levels to customer expectations)
Resourcing is sufficient for projected works programme	Considerable effort has been made to ensure work volumes are deliverable by our key providers. However, unanticipated labour constraints may cause works to be delayed, and/or labour costs to rise.
Little change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost and duration of works
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury, where specific forecasts unavailable)	Deviation from expected material, labour, overhead input costs, will result in increased costs to works programmes. The projected treatment of network constraints may change, depending on the specific changes to each input cost factor.
Future technologies that may impact work methodologies are not priced into cost estimates	Planning for the inclusion of non-commercial or unprofitable technologies is imprudent, due to uncertainty of timing, costs, and impacts. Cost savings may occur if technologies develop to a stage where implementation is feasible and economic.
No significant changes in national energy policy	Changes to current national energy policy may affect consumer and/or industry behaviour in such a way that OJV investments decisions become un-economic.

Assumption	Discussion & Implications
No significant changes to the shift towards cost-reflective pricing	The Electricity Authority has, in recent publications, signalled an expectation for electricity distributors to progress towards more service-based and cost-reflective pricing. Challenges from external parties to pricing reform may cause currently proposed investments to be reconsidered.
No significant changes to requirements regarding resource consenting, easements, land access (private, commercial, local, and national authorities)	Increasing requirements are likely to result in increased costs.
No material changes to customer expectations of service levels	Changes to customer expectations will require adjustment to service levels and subsequent investments.
No significant changes to local and/or national government development policies	Developmental policies have the potential to affect aggregate and local demand. Investment levels will be adjusted to suit.
Improving industry co-operation	Deterioration in industry co-operation may result in duplicated and uncoordinated efforts and higher costs.
Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.	Historic trend expected to continue.
Step changes in underlying growth are considered unlikely based on historical trending over a long period. Population growth for sizing of equipment is based on the high projection.	Lower population growth may result in some equipment being oversized. Likely impact on total project cost is minor. Higher population growth may initiate capacity improvement works earlier.
Abnormal price movements caused by major external events (war, terrorism, union action, natural disaster) affecting pricing of equipment or labour substantially are difficult to predict and not allowed for in estimates.	These major external events are unable to be predicted with any certainty and OJV must react accordingly to any changes.
The line pricing methodology has been updated to reflect more service based and cost reflective pricing, this has been achieved by the introduction of "peak", "shoulder" and "night" variable pricing periods, which is designed to change customers behaviours and encourage them to use energy in the non-peak times. Time will tell if the new methodology changes the behaviours.	Actual future demands may depart significantly from forecasts. Prediction of demand growth is uncertain due to new line pricing methodology. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in OJV's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.

1.4 Potential Variation Factors

The following factors have the potential to cause significant variation between the forecasts in this AMP and the actual information that will be included in future disclosures.

Table 9: Variation Causes and Implications

Cause of Variation	Implications
Cost and time estimate inaccuracies	Project cost increase. Timing may vary, resulting in lower work efficiencies. These may trigger review of project approval if variations are sufficiently large.
Variation in inflation rates and exchange rates	Higher input costs than forecast, less work being done for the same amount of money.

This has changed from the 2023-33 AMP which read:

The following factors have the potential to cause significant variation between the forecasts in this AMP and the actual information that will be included in future disclosures.

Table 10: Variation Causes and Implications

Cause of Variation	Implications
Cost and time estimate inaccuracies	Project cost increase. Timing may vary, resulting in lower work efficiencies. These may trigger review of project approval if variations are sufficiently large.
Variation in inflation rates and exchange rates	Higher input costs than forecast
Staffing resource losses or inability to recruit as required	Higher cost to be able to meet staffing level required to complete works. This may be coupled with deferment of investment programme, or outright cancellation of certain works if issues become ongoing.
Reactive work varying from that estimated	Deferment of capital or planned maintenance work, if those works are dependent on the asset being in-service. Deferment of capital or planned maintenance work may also arise from staff resourcing constraints.
Equipment failure (especially large capital plant) which may influence future economic options	Greater replacement costs for unplanned failure. Greater costs to maintain supply to customers, until replacement. Review of equipment selection and work methodologies.
New safety issues identified and initiatives created	Higher labour or material costs. Triggers reviews of work methodologies on existing scheduled works.
Reprioritisation of projects as new work activities are identified	Increased scope, scheduling, design, planning costs if not communicated sufficiently ahead of time. Also requires revision of longer-term investment programme.
Detailed analysis of the available options for projects commencing in the short to medium term, which may indicate an alternative approach is preferable to that assumed for long-range forecasting	Similar implications compared to if new work activities are identified.
Greater demand growth than anticipated levels, especially new large industry, or customers	May cause certain capital investments to be accelerated, or advanced. May constrain staffing resources.

Cause of Variation	Implications
Lower demand growth than anticipated levels, especially loss of existing industry or customers	May cause certain capital investments to be deferred or cancelled.

Issues related to this edition of the AMP are based on actual and potential impact of the Covid-19 pandemic.

Impact of the Covid-19 pandemic

The Covid-19 pandemic has spread around the world and several new strains of the coronavirus are appearing. Countries are in various stages of lockdown and social distancing. This is affecting the OJV' supply chain and it may have an effect on the resources available to execute this AMP.

New Zealand was in various stages of lockdown and social distancing for the first part of the financial year. This was a test to the leadership of PowerNet (managing company of the OJV networks). One of the key lessons learnt and applied was that leaders are required to communicate frequently and across more and varied channels.

The OJV Board and PowerNet's management team worked together to devise a set of actions that would limit the impact of the pandemic on OJV's customers and ensured that "*working from home*" scenarios could be accommodated. Leaders shared strategies in an open and transparent manner of how the organisation was going to move ahead, and how well the initiatives were working.

The payoff from this leadership communication was powerful. Employees realised that we are in a critical business sector, felt more connected and had a sense of purpose. This allowed OJV to keep a large part of the planned work flowing. Some challenges that had to be overcome are listed below.

- Social distancing protocols and work bubbles meant that certain types of work could not be executed, particularly work that may have involved some form of interaction with the public.
- Suppliers and manufacturers of equipment went into lockdown. Combined with utilities trying to source equipment for emergency use, this created difficulty in obtaining certain equipment and material.
- Offshore equipment delivery was disrupted, leading to delays in work execution.
- Only a limited number of people were allowed on each work site at any one time. This included contractors required on projects.
- It took several weeks to develop the systems and processes that allowed employees and contractors to work safely. During this 6-week period work was limited to fault responses.

Most challenges were addressed, but there were cost and project schedule implications. OJV could not completely catch up with all the work that fell behind and projects that were planned for the year, where delays affected the planned expenditure. It is assumed that negative effects of Covid-19 will be continuously managed during this financial year and will not have a significant impact on OJV’s ability to execute this AMP.

2 The OJV Business Environment

2.4 2024-34 Update Commerce Commission Determination – Financial Impact

DPP3 introduced a revenue cap as opposed to the previous price cap.

The result for OJV is allowable revenue in 2020/21 ($M) of $25.78 million. This is a reduction of 5% in revenue. Directly related to the revenue targets are the operating expenditure targets.

The allowable OPEX for 2020-2025 is $48.45 million and it is distributed as follows.

2020/21	2021/22	2022/23	2023/24	2024/25
9.16	9.43	9.70	9.96	10.20

The allowable CAPEX for 2020-2025 is $82.50 million and it is distributed as follows.

2020/21	2021/22	2022/23	2023/24	2024/25
13.99	13.50	18.00	23.07	13.93

The Business Environment was described in the 2023-33 AMP:

OJV's business goals are driven by its stakeholder's interests - primarily meeting shareholders' and customers' expectations. The context for business operations is also shaped by drivers ranging from governmental and regulatory strategies (that may create incentives or impose constraints), to natural events such as the unpredictability of weather or the laws of physics.

2.1 Vision and Strategies

OJV's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of various stakeholders while recognising the need to work within constraints imposed by both stakeholders and wider issues that affect asset management. Managing conflicts between stakeholders and numerous risks to the business are acknowledged.

Vision Statement

To be one of the top performing New Zealand electricity distribution businesses, with an integrated investment portfolio.

Corporate Strategy

The following are key corporate drivers from OJV's Strategic Plan.

- Manage operations in a progressive and commercial manner.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.

- Provide its customers with reliable and affordable service.
- Understand and effectively manage appreciable business risk.
- Strive to be an efficient but effective operation.
- Pursue alternative technologies and energy forms within the current regulatory requirements.

Asset Management Strategy

OJV's asset management strategy is based on the following guiding principles.

- Safety by design using the ALARP (as low as reasonably practicable) risk principle.
- Minimise long term service delivery cost through condition monitoring and refurbishment.
- Replace assets at their (risk considered) economic end of life.
- No material deterioration in the condition or performance of the networks.
- Facilitate network growth through timely implementation of customer driven projects.
- Maintain supply quality and security with network upgrades to support forecast growth.
- Set performance targets for continuous improvement.
- Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather.
- Utilise overall cost benefit at all investment levels including the "do nothing" option.
- Standardise and optimally resource to provide proficient and efficient service delivery.
- Follow new technology trends and judiciously apply to improve service levels.
- Undertake initiatives to increase existing asset life or capacity.
- Consider alternatives to status quo solutions.
- Improve efficiency of electricity distribution for the net benefit of the customer.
- Achieve 100% regulatory compliance.
- Minimise environmental harm.

Health, Safety and Environmental Strategy

People and equipment can be put at risk if safety is not foremost in our thinking. The protection of people and the environment is considered in every decision we make, and in every action we take. EIL is committed to:

- Providing a safe and healthy work environment
- Supporting our people to stop work and pause for safety when someone feels unsafe
- Contributing as individuals to our safety first culture
- Ensuring the electricity networks that we manage do not put communities or businesses at risk

- Managing any activities with high potential injury consequence by implementing critical controls
- Ensuring our vehicles, plant and equipment are fit for purpose, well maintained, and safe for use
- Engaging our people through leadership, consultation, communication and partnerships
- Having well trained people that understand what they do and how they do it
- Engaging with the public to increase their awareness of risks
- Collaborating with the industry to enhance safety standards
- Committed to fulfil all legal requirements
- Continually striving for improvement of the Health and Safety Management System to create a safer workplace and networks
- Implementing effective systems

Interaction of Goals/Strategies

OJV's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 11.

Table 11: Corporate and Asset Management Strategy Linkages

Corporate Strategies

- Provide its customers with above average levels of service.
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.
- Understand and effectively manage appreciable business risk.
- Manage operations in a progressive and commercial manner.
- Strive to be an efficient but effective operation.

Asset Management Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
No material deterioration in the condition or performance of the networks	✓	✓			✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards: seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			

Corporate Strategies					
Provide its customers with above average levels of service.					
Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value.					
Understand and effectively manage appreciable business risk.					
Manage operations in a progressive and commercial manner.					
Strive to be an efficient but effective operation.					
Asset Management Strategies	Strive to be an efficient but effective operation	Manage operations in a progressive and commercial manner	Understand and effectively manage appreciable business risk	Undertake new investments	Provide its customers with above average levels of service
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

2.2 Business Role-players

This section describes the role-players in OJV's business and their interests. The paragraphs explain how interests are met and how conflicts between role-players' expectations are managed.

Associations

OtagoNet Joint Venture (OJV) is the electricity lines business that conveys electricity to much of rural Otago and to Frankton, supplying approximately 18,900 customer connections on behalf of energy retailers. OJV discloses on behalf of the following entities:

- OtagoNet, which distributes power to rural Otago.
- Lakeland Network (LNL), which distributes electricity in the Frankton, Wanaka and Cromwell areas of Central Otago.

The Lakeland network is not contiguous to the OtagoNet network and meets the threshold that triggers additional sub-network disclosures.

Ownership

The ownership of OtagoNet and LNL is identical:

- 24.9% owned by Electricity Invercargill Limited (EIL)
- 75.1% owned by The Power Company Limited (TPCL)

The inter-relationship of these entities with the various holding companies and shareholders (along with the accounting treatment of results), is described in OJV's annual report.

Governance

OJV's uses PowerNet as their contracted asset management company.

- The main governance accountability is between OJV's Governing Committee (Board) and shareholder with the principal mechanism being the Joint Venture Agreement (JVA). Inclusion of financial objectives in the agreement makes OJV's Board accountable for overseeing the price-quality trade-off inherent in projecting expenditure. OJV (as of 31 March 2023) has four directors:
  - Peter Moynihan (Chair)
  - James Carmichael
  - Rob Jamieson
  - Wayne Mackey
- The second level of accountability is between OJV's Board and PowerNet with the principal mechanism being the management agreement that specifies a range of strategic and operational outcomes to be achieved.

Stakeholders and their Interests

A stakeholder is identified as any person or organisation that does or may do any of the following.

- Have a financial interest in OJV (be it equity or debt).
- Pay money to OJV (either directly or through an intermediary) for delivering service levels.
- Is physically connected to OJV's network.
- Use OJV's network for conveying electricity.
- Supply OJV with goods or services (includes labour).
- Is affected by the existence, nature, or condition of the network (especially if in unsafe condition).
- Has a statutory obligation to perform an activity in relation to the OJV network's existence or operation (such as request disclosure data, regulate prices, investigate accidents or District Plan requirements).

OJV's identified stakeholders are listed in the following tables - stakeholder's interests (Table 12) and how these interests are identified (Table 13).Table 14 describes how stakeholder's interests are accommodated in OJV's asset management practices.

Table 12: Interests of Key Stakeholders

Interests	Viability	Price	Quality	Safety	Compliance
The Power Company (Shareholder)	✓	✓	✓	✓	✓
Electricity Invercargill (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Councils (as regulators)				✓	✓

Transport Agency				✓	✓
Energy Safety				✓	✓
Industry Representative Groups	✓	✓	✓		
Public (as distinct from customers)				✓	✓
Mass-market Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Energy Retailers	✓	✓	✓		
Suppliers of Goods and Services	✓				
Land owners				✓	✓
Bankers	✓	✓		✓	✓

Transpower, equipment suppliers and service providers are also regarded as key stakeholders, however they influence OJV rather than OJV having a significant effect on their viability, price, quality, safety or compliance.

Table 13: Identification of Stakeholders' Interests

Stakeholder	How Interests are Identified
The Power Company (Shareholder)	• By their approval • Regular meetings between the directors and executive
Electricity Invercargill (Shareholder)	• By their approval • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers as part of their on-going development needs • Customer consultation evenings (meetings open to public) • Annual customer surveys
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PNL Staff
Ministry of Business, Innovation & Employment	• Release of legislation, regulations, and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity & Gas Complaints Commission	• Reviewing their decisions about other lines companies
Councils (as regulators)	• Formally as necessary to discuss issues such as assets on Council land • Formally as District Plans are reviewed
Transport Agency	• Formally as required
Energy Safety	• Promulgated regulations and codes of practice • Audits of OJV's activities • Audit reports from other lines businesses
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth around the city • Feedback from public meetings
Mass-market Representative Groups	• Informal contact with group representatives

Stakeholder	How Interests are Identified
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Suppliers of Goods & Services	• Regular supply meetings • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet' s CEO & CFO • By adhering to OJV's treasury/borrowing policy • By adhering to banking covenants

Table 14: Accommodating Stakeholder's Interests

Interest	Description	How OJV Accommodates Interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in OJV.	Stakeholder's needs for long-term viability are accommodated by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as the stakeholders could obtain from a term deposit at the bank plus a margin to reflect the ever-increasing risks to the capital in the business. Earnings are set by estimating the level of expenditure that will deliver the returns and Service Level maximised within those constraints accordingly.
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than what OJV's customers want.	OJV's total revenue is determined by the regulated price path threshold. Prices will be managed to within the limits prescribed unless doing so would comprise safety or viability. Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders. OJV's pricing methodology is intended to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this. This charge is being phased out through Government regulatory changes
Supply Quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholder's needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality but also with many customers indicating a willingness to accept a reduction in supply quality in return for lower line charges.
Safety	Staff, contractors, and the public at large must be able to move around and work on the network in total safety.	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, protection systems are working, all enclosures are kept locked and all exposed metal within touching distance of the ground is earthed. The safety of staff and contractors is ensured by providing all necessary equipment, improving safe work practices, and ensuring that they are stood down in unsafe conditions. Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints faced regarding private land and road reserve.
Compliance	Compliance with many statutory requirements	All safety issues will be adequately documented and available for inspection by authorised agencies.

Interest	Description	How OJV Accommodates Interests
	ranging from safety to disclosing information is compulsory.	Performance information will be disclosed in a timely and compliant fashion.

OJV's commercial goal is to deliver a sustainable earnings stream to their shareholders. This creates a primary driver for OJV, and formal accountabilities to the shareholder are in place for financial and network performance.

Connected customers (via electricity retailers) provide OJV's revenue in return for the services provided by the OJV network assets. Due to the importance OJV places on meeting customer's expectations, annual customer surveys are undertaken to monitor customer satisfaction, with service level targets set to ensure standards are maintained or improved. See Section 5 (Service Levels) for details of these surveys, customer feedback and performance targets.

OJV is required to compile and publicly disclose performance and planning information (including the requirement to publish an AMP). In addition, OJV is subject to price and quality regulations and there should not be any substantial decline in network reliability measures. These requirements are listed under Part 4 of the Commerce Act 1986.

Regulatory restrictions on generating and retailing energy is established under the Electricity Industry Act 2010 and requirements for the connection of distributed generation established under the Electricity Industry Participation Code. Electricity lines businesses are increasingly being required to give effect to many aspects of government policy.

Managing Conflicting Interests

When conflicting stakeholder interests are identified, an appropriate resolution needs to be determined. The following prioritisation hierarchy is used to analyse conflicting issues and to establish available options.

1. **Safety**. Top priority is given to safety. The safety of staff, contractors and the public are of paramount importance. These factors are highly considered in asset management decisions.

2. **Viability**. Viability is a secondary consideration, because without it OJV would cease to exist, making supply quality and compliance pointless.

3. **Pricing**. OJV gives third priority to pricing (noting that pricing is only one aspect of viability). OJV recognises the need to adequately fund its business to ensure that customers' businesses can operate successfully, whilst ensuring that there is not an unjustified transfer of wealth from its customers to its shareholders.

4. **Supply Quality. S**upply quality is the fourth priority. Good supply quality makes customers, and therefore OJV, successful.

5. **Compliance**. A lower priority is given to compliance that is not safety and supply quality related.

Once an appropriate resolution has been determined, a recommendation is presented to management. A decision may be taken by the management team or matters be escalated to the OJV Board if required.

2.3 External Business Influences

There are several other issues (listed below) that are not directly related to stakeholders but have a significant impact on OJV's asset management practices. Strategies might be developed to effectively manage these concerns.

- Competitive pressures from other lines companies that might try to supply OJV customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, which could potentially strand conventional distribution utilities.
- Local, national, and global economic cycles which affect growth and development.
- Changes to the Otago climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.
- Ensuring sufficient funds and skilled people are available long term to resource OJV's service requirements.
- Technical regulations including such matters as limiting harmonics to specified levels.
- Safety requirements such as earthing of exposed metal and line clearances.
- Asset configuration, condition, and deterioration. These parameters will significantly limit the rate at which OJV can re-align their large and complex asset base to fit ever-changing strategic goals.
- Physical risk exposures: exposure to events such as flooding, wind, snow, earthquakes, and vehicle impacts.
- Regulatory issues: for example, if the transport agency required all poles to be moved back from the carriage way.

2.4 Commerce Commission Determination – Financial Impact

Part 4 of the Commerce Act 1986 (the Act) requires the Commerce Commission to reset the current DPP for EDBs that are subject to price-quality regulation four months before the end of the current DPP period. From 1 April 2020, EDBs are subject to requirements set out in the DPP determination.

Changes in the way consumers and other industry participants make use of distribution networks, innovations in the way EDBs deliver services, electrification driven by decarbonisation, and the risk of increasingly severe weather events all have the potential to reshape investment needs and quality expectations in unpredictable ways.. In addition, the drive to move away from fossil fuels are creating some challenges to the electricity distribution industry. The stated intent of the Commerce

Commission is to provide sufficient flexibility to accommodate increasing uncertainty and change across the electricity distribution sector.

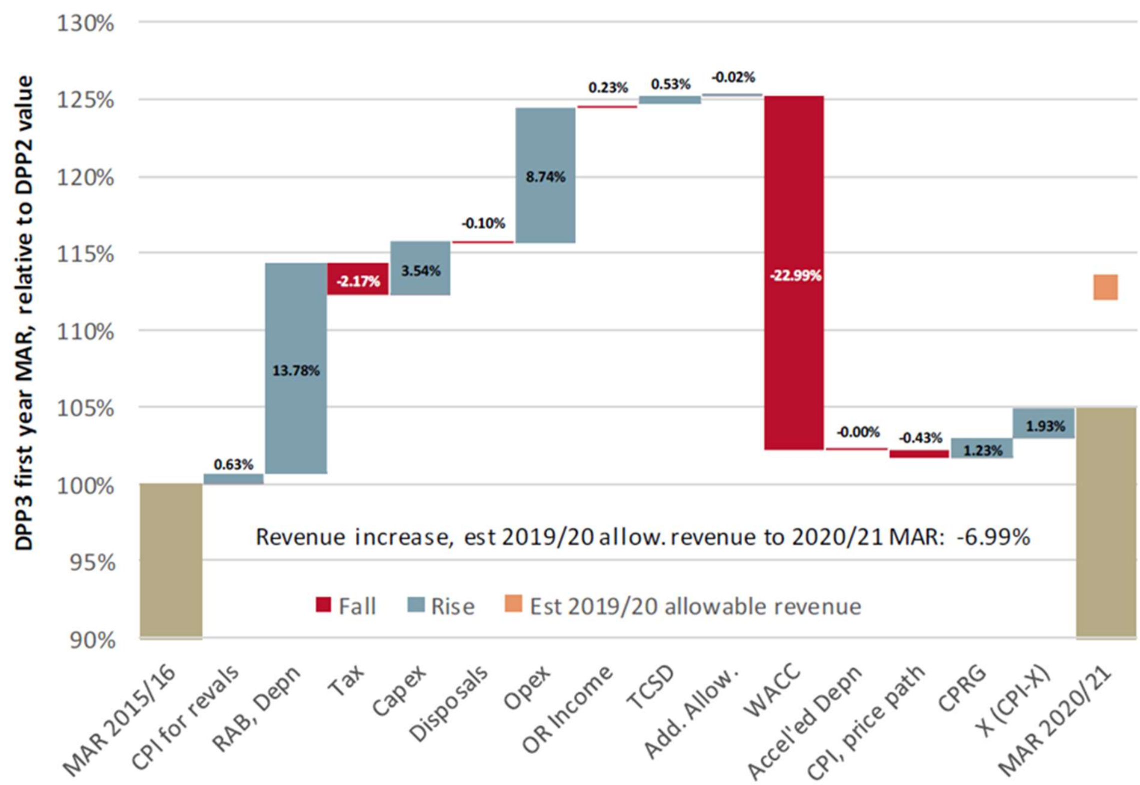
The DPP3 introduces a revenue cap as opposed to the previous price cap. This is intended to give EDBs the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management as well as to give EDBs greater certainty about revenue recovery. Setting revenue limits means that profitability depends on the extent to which EDBs control costs.

DPP3 revenue caps assume a reduction in the weighted-average cost of capital, as reflected in the current state of the broader economy. Low global interest rates have led to lowered profitability expectations across many sectors.

The Commerce Commission has set a net revenue allowance of $1.01 billion in the first year of the DPP3 period across the 15 regulated EDBs. This is an overall decrease of 6.7% relative to allowances in the final year of DPP2.

The methodology followed was to add the forecasts of each EDBs over the DPP3 period together, then spreading this revenue out over the period such that they increase at a consistent rate of forecast CPI-X, resulting in the 'maximum allowable revenue' (MAR). The overall result is presented in the following figure (copied from the Commerce Commission's Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision document).

Figure 9: Financial Impact of DPP3



The result for OJV is allowable revenue in 2020/21 ($m) of $25.78 million. This is a reduction of 5% in revenue. Directly related to the revenue targets are the operating expenditure targets. The allowable OPEX for 2020-2025 is $48.45 million and it is distributed as follows.

2020/21	2021/22	2022/23	2023/24	2024/25
9.16	9.43	9.70	9.96	10.20

The allowable CAPEX for 2020-2025 is $82.50 million and it is distributed as follows.

2020/21	2021/22	2022/23	2023/24	2024/25
13.99	13.50	18.00	23.07	13.93

Expenditure is being managed taking both the allowable levels as well as the cash flows in the EDBs into account. ComCom has introduced reopeners for significant unforeseen or uncertain capital expenditure projects that will allow EDBs to undertake investments in response to changing conditions without risking capital under-recovery.

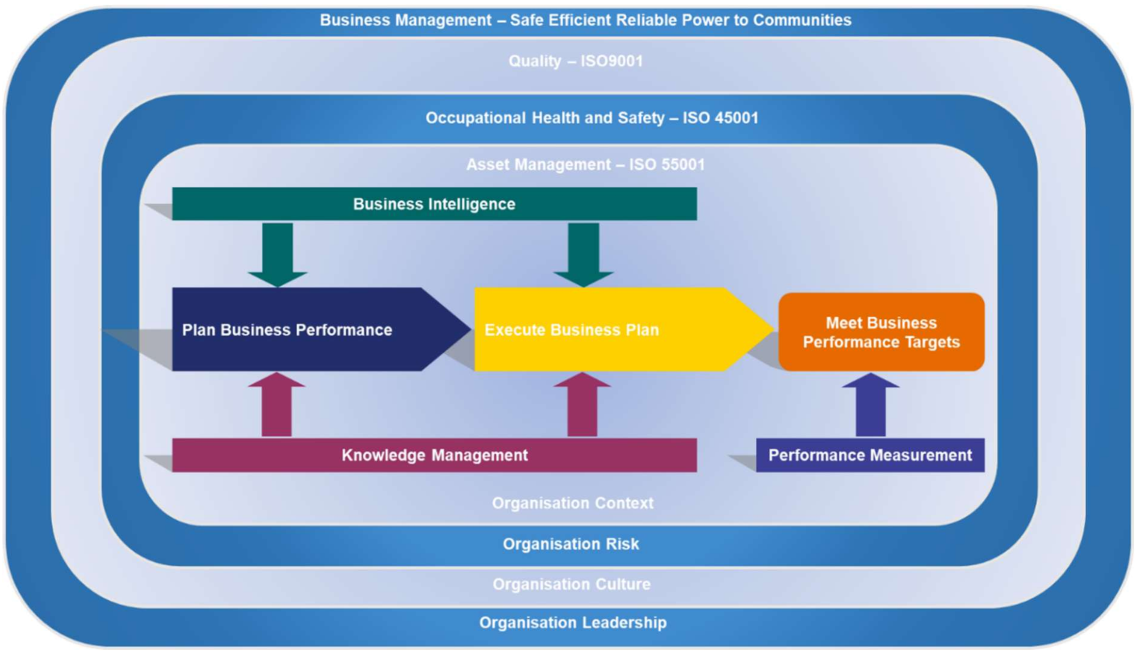
2.5 Planning Processes

OJV's planning processes and associated documents are described in the next sections.

Business Planning

The business planning, execution and performance measurement processes are presented in the next figures.

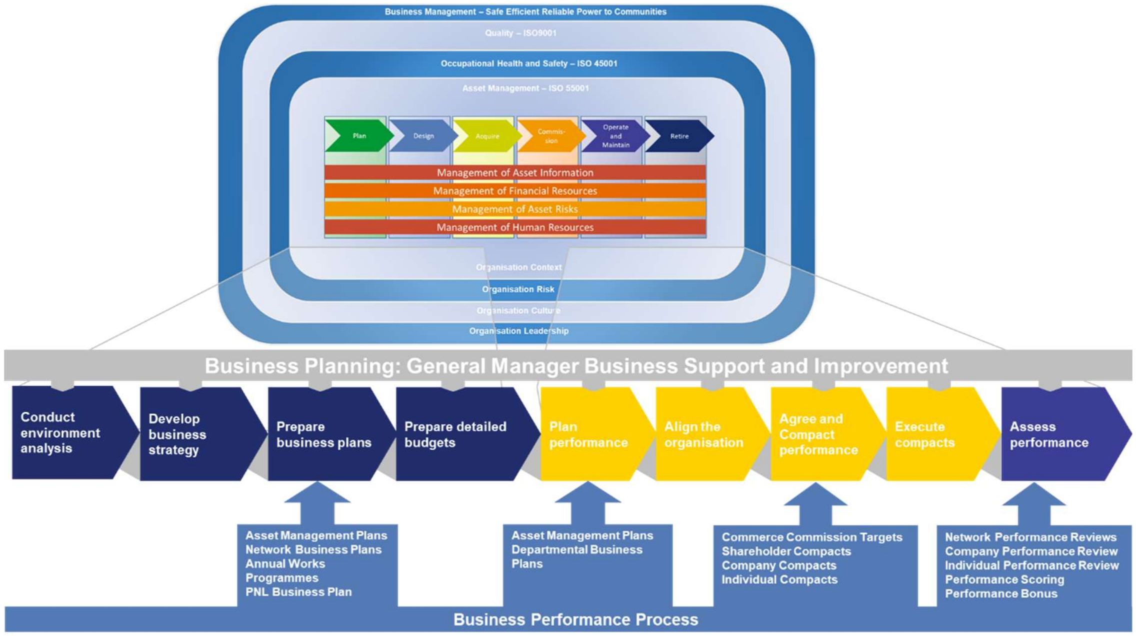
Figure 10: Business Planning and Execution Processes



Business planning take place within the overall framework of Quality, Occupational Health and Safety and Asset Management. The environment is scanned to determine threats and opportunities and gather other business intelligence. This is combined with knowledge around the strengths and weaknesses of internal processes. Business performance is planned to meet stakeholder requirements. The stakeholder requirements are embodied in targets OJV has to meet. The business plan is executed and the results are measured against the targets to evaluate business performance.

Figure 11 shows the process in more detail and indicates the performance elements from company level through to individual performance compacts. Individuals' performance against the compacts are evaluated for the performance incentive program.

Figure 11: Business Support and Improvement Processes



In addition to the AMP, PowerNet annually produces the following documents on behalf of OJV. These documents are approved by OJV as part of the company's planning processes.

Annual Business Plan

Each year, the first three years of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into OJV's Annual Business Plan (ABP). The AWP for the three years ahead is an important component of the ABP.

The ABP defines the priorities and actions for the year ahead which will contribute to OJV's long-term alignment with their vision, objectives, and strategies, while fully understanding that this alignment process must at times cater for "moving goal posts". The ABP contains the following.

- Core Business, Vision Statement and Critical Success Factors.
- Commercial Objectives, the Nature and Scope of Commercial Activity and Company Policies.
- Annual Works Programme (first three years).
- Business Plan Financials and Business Unit Reports.

Progress updates are reported on a monthly base to assist in monitoring of performance and delivery to plan.

Annual Works Programme

The Annual Works Programme (AWP) is produced as part of the AMP development process and is included in the AMP's development and lifecycle planning sections. It covers the same ten-year planning horizon and lists the works to be undertaken for each financial year.

The AWP details the scope for each activity or project identified, sets the associated budget for the first year and forecasts expenditure for future years. Critical activities are to firstly ensure that this annual works program accurately reflects the projects in the AMP and secondly to ensure that each project is implemented according to the scope prescribed in the works program. Ensuring the AWP is achievable requires careful consideration of the available workforce and management capabilities which is discussed in Section 9.

Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between OJV's corporate vision, asset management objectives, business drivers, strategies and key planning documents is presented in the next figure.

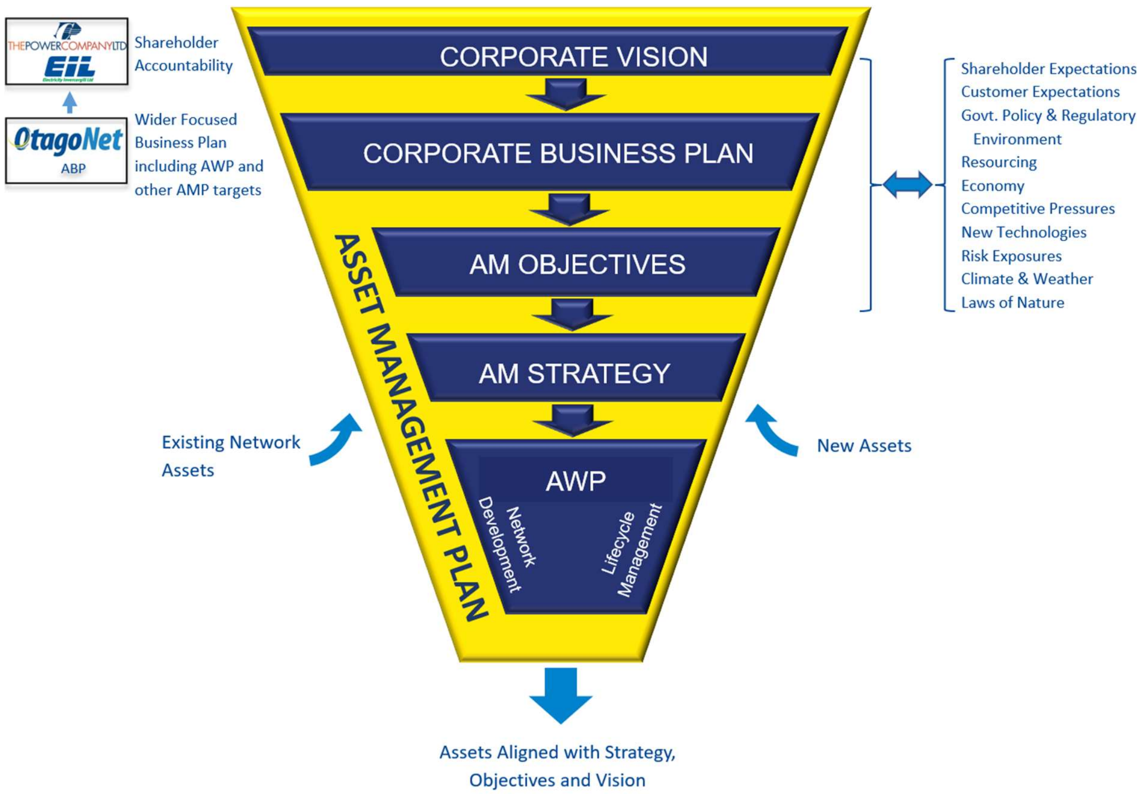
The vision leads to the objectives for OJV's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within OJV's asset management company PowerNet and for the OJV board.

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with OJV's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which shape the strategies developed. They also shape the asset management objectives and the corporate vision. However, these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time. The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

The AMP (and especially the AWP incorporated into the AMP) sets and drives asset management works and expenditure to reshape network assets and is prepared in a format that assists communication of the key deliverables. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and OJV's corporate vision whilst meeting stakeholder expectations, in particular those of the shareholder and network customers.

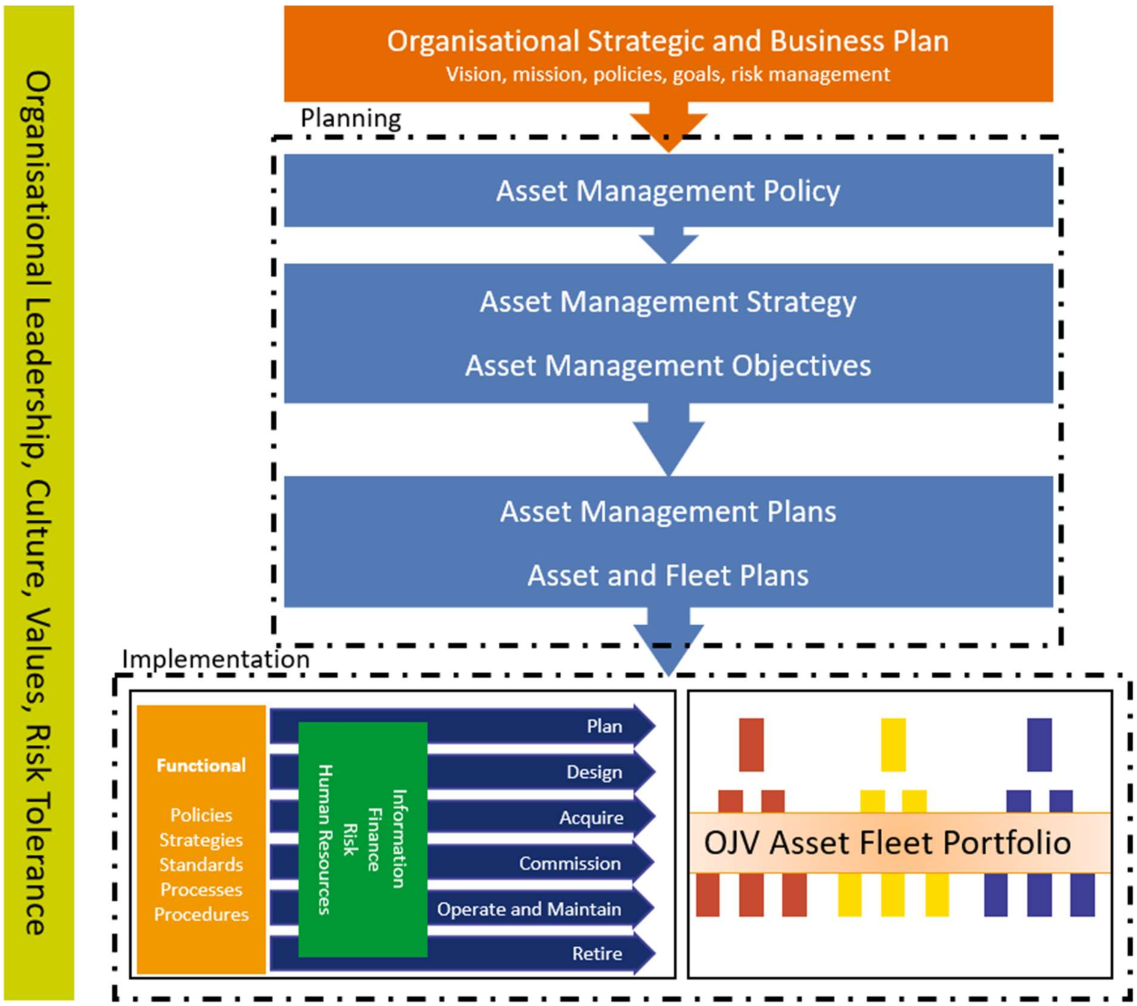
Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP; these together with any wider business issues provide the overall business planning summary used by the wider management team and OJV Board.

Figure 12: Interaction between Objectives, Drivers, Strategies and Key Documents



This happens within the framework of our asset management policy, asset management strategy and asset management objectives. Figure 13 shows the framework we use to manage our assets.

Figure 13: Asset Management Framework



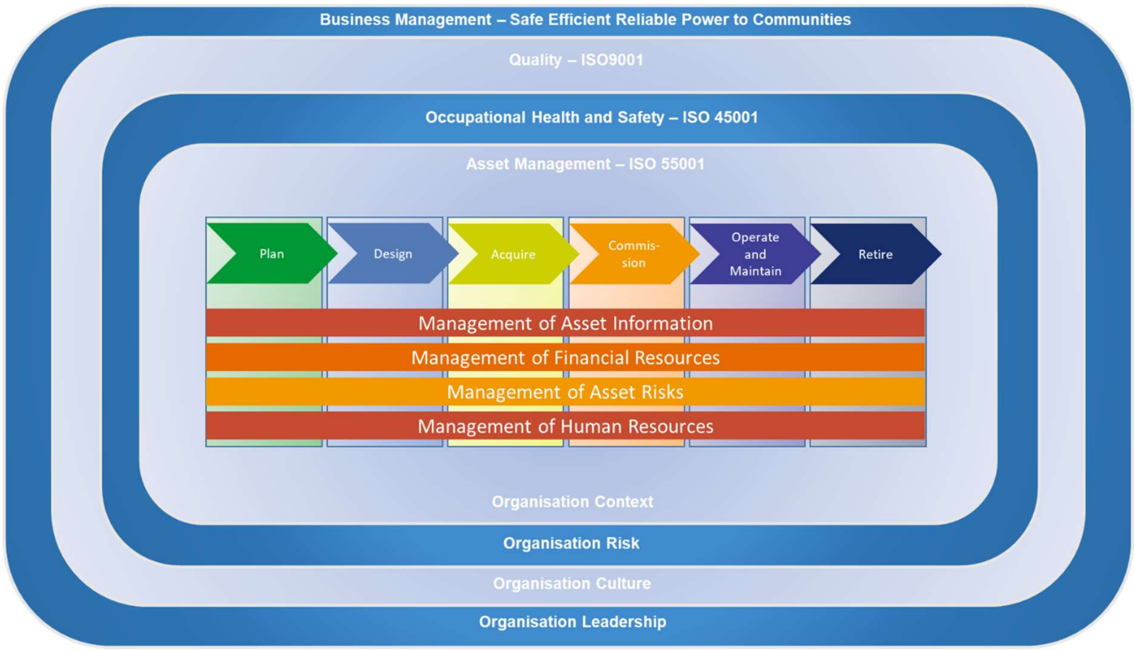
Asset Management Planning

Asset life cycle management processes are demonstrated in the next figure. The asset life cycle phases are the following:

- Plan
- Design
- Acquire (including construction)
- Commission
- Operate and maintain
- Dispose

These phases are underpinned by the foundations of asset information management, financial resource management, risk management and human resource management. These are discussed in further detail in Chapter 6 - Asset Management Strategy.

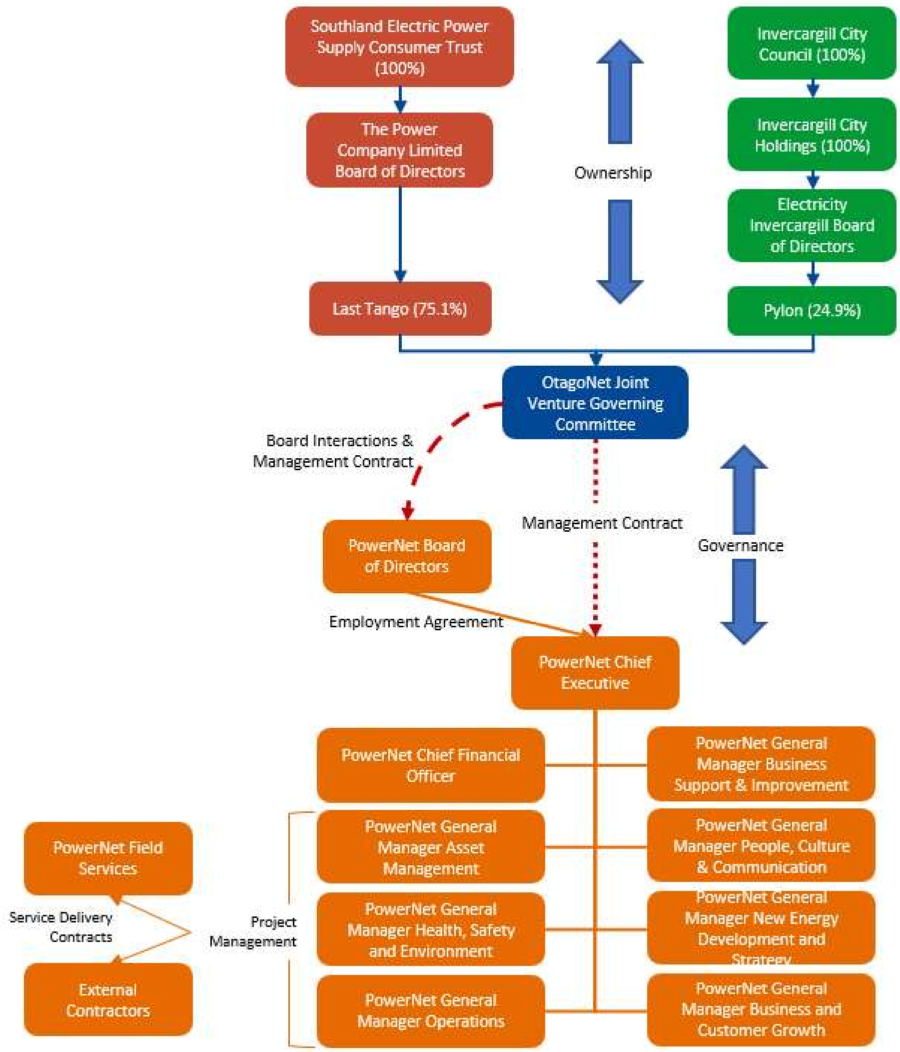
Figure 14: Asset Management Processes



2.6 Structure and Accountabilities

OJV's ownership, governance and management structure is depicted in Figure 15. Each level of management has defined financial authority limits set out in the PowerNet Financial Authorities Policy. It includes general financial authority levels and increased levels specifically for project work previously approved in the AWP. Most projects in the AWP are approved by the OJV Board as part of ABP process in the previous year.

Figure 15: Governance and Management Accountabilities



OJV Governing Committee (Board)

Any new project over $100,000 added or variation by more than +10% or -30% (for projects over $100,000) to the approved AWP will need to gain approval from the OJV Board. Large projects with capital budgets exceeding $1,000,000 are required to be supported by a business case explaining the project scope and justification. The business case will generally include a detailed cost-benefit analysis of the recommended scope over alternative options.

The OJV Board receives monthly reports that cover the following items.

- Network Reliability – this lists all outages over the last month, and trends regarding the reliability targets.
- Network Quality – detail of outstanding supply quality complaints and annual statistics thereof.

- Network Connections – monthly and yearly details of connections to the network.
- Use of Network – trend of the energy conveyed through the network.
- Revenue – detail on the line charges received.
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network.
- Works Programme – Summary expenditure actuals and forecasts by works programme category with notes on major variations.

Accountability at Executive Level

Overall accountability for the performance of the electricity network rests with the Chief Executive of PowerNet. The principal accountability mechanism is the Chief Executive's employment agreement with the PowerNet Board which reflects the outcomes specified in the management contract between OJV's Board and PowerNet.

Accountability at Management Level

There are eight level two managers reporting directly to PowerNet's Chief Executive. Their respective employment agreements are the principal accountability mechanisms. The General Manager Asset Management has the most influence over the long-term asset management outcomes, through his responsibility for preparation of the AMP. The AMP guides the nature and direction of the other managers' work.

Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team and Planning Team (under the General Manager Asset Management), each manage their respective major projects, technical projects and distribution projects which make up the AWP. Their objectives are to deliver the AWP projects on time, to scope and to budget while also delivering to the AWP works category and overall CAPEX and OPEX budgets. Major Projects typically tenders the work out to external consultants and contractors through open tender, while technical and distribution projects utilise PowerNet's in-house field services.

Utilisation of external contractors are contractual and structured as follows.

- Purchase Order – generally only minor work.
- Fixed Lump Sum Contract – generally on-going work.
- Term Service contract – where we require regular services from a contractor.
- Engineering Contract – specific project work.

Each type details the work to be undertaken, the standards to be achieved, detail of information to be provided and payments schedule.

Accountability at Work-face Level

PowerNet's internal field staff are managed within PowerNet's Operations Team to deliver work divided into technical and distribution projects. External contractors are used for vegetation management (Asplundh) and communications network maintenance and projects (Ventia). Civil works including cable trenching and earthworks for zone substations are typically completed by external contractors. External contractors are typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets and include the following.

- Decom Limited.
- Ventia Limited.
- Electrix Limited.
- Local Electrical Inspectors.
- Asplundh Tree Expert (NZ) Limited.
- Corys Limited.
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Daysh, Ergo Consulting, Energetick, Decom).

2.7 OJV's Supply Area

OJV supplies 18,881 customers across four geographically separate areas:

- Otago - The northern rural Otago area bounded by Waitati, Shag Point, Falls Dam and Lake Mahinerangi, and the southern rural Otago area bounded by Taieri Mouth, Beaumont, Waipahi, and the Maclennan Range.
- Frankton - The area between Lake Hayes, the Frankton arm of Lake Wakatipu and Jacks Point, consisting of several non-contiguous sections as the area is serviced by both LNL and Aurora.
- Wanaka - A small area north east of Wanaka and south of the Clutha River, embedded within the Aurora network.
- Cromwell - A small area on the north side of Cromwell, embedded within the Aurora network.

Figure 16: Otago Distribution Area

Figure 17: Frankton Distribution Area

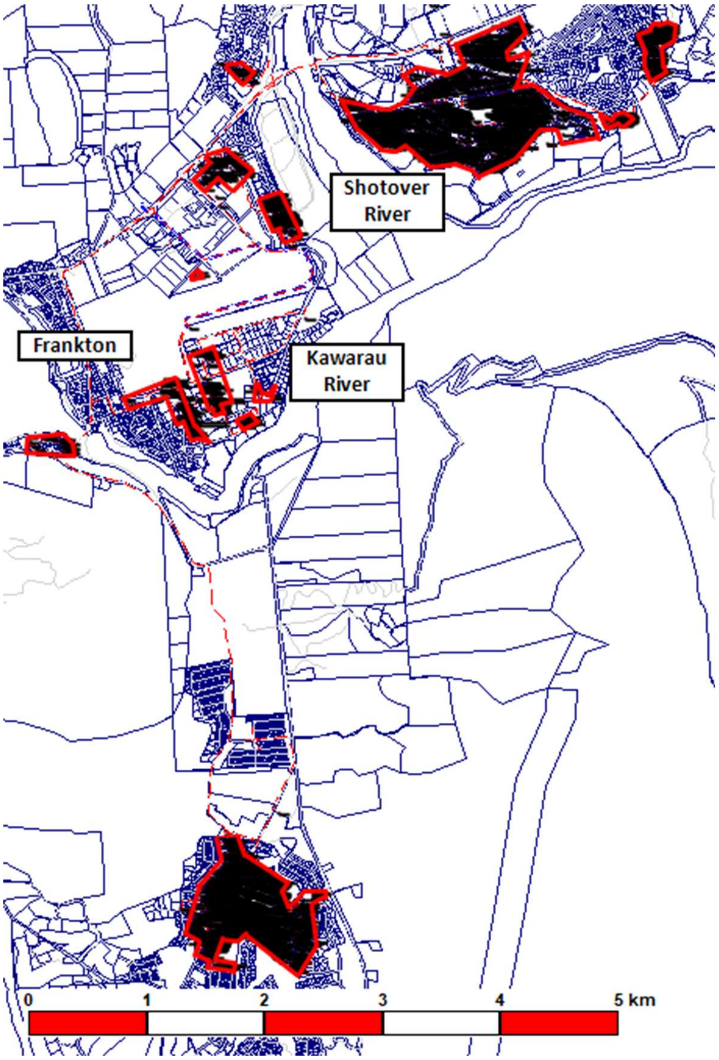


Figure 18: Wanaka Distribution Area

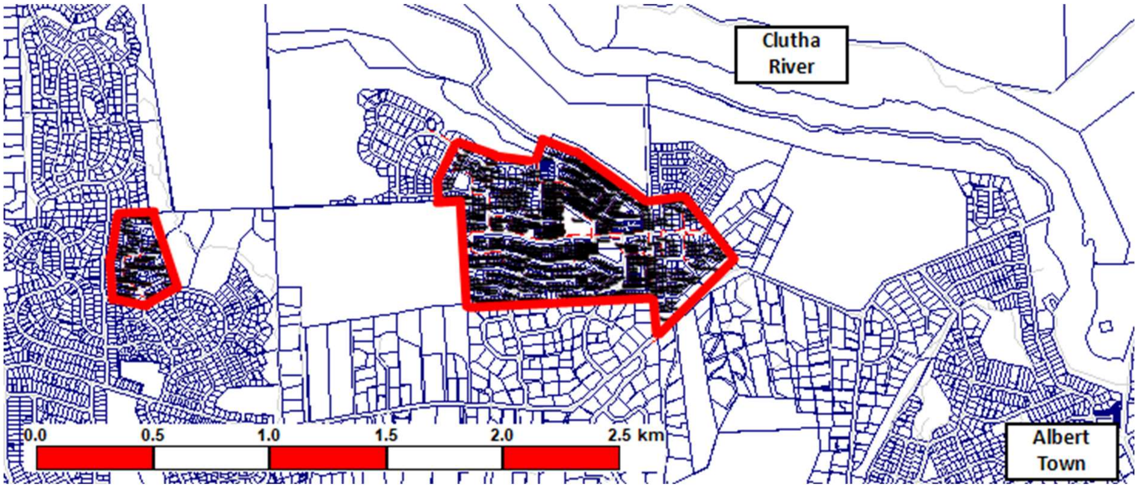
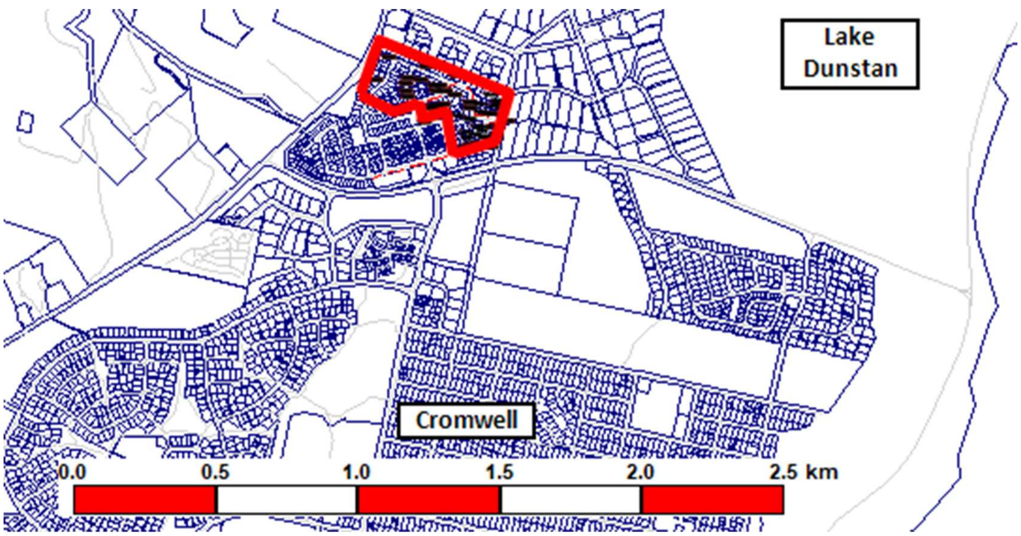


Figure 19: Cromwell Distribution Area



OJV's largest customer is Oceana Gold's Macraes Flat gold mine which consumes approximately one-third of the total energy supplied by OJV; therefore any significant change of load there would affect the energy supplied by OJV as a whole.

2.8 Quality of Service (Regulated Service Levels)

Quality of service incentives is a major focus area of the Commerce Commission's DPP3 determination. The approach followed is one of '*no material deterioration*'. The stated intent is that aligning reliability incentives to the value consumers place on reliability frees EDBs (within certain bounds) to target the level of reliability and of price that best meets the expectations of their consumers. Additionally, normalisation is intended to prevent the effects of severe storms being mistaken for signs of deterioration. The principles embodied within the ComCom quality standards are the following.

- Separating planned and unplanned reliability standards.
- Setting the unplanned reliability standards at 2 standard deviations above the normalised historical average, and defining contraventions on an annual basis, rather than a 'two-out-of-three' year basis.
- Setting the planned reliability standard at three times the historical average and assessing it on a regulatory period basis.
- Capping the inter-period (DPP2 to DPP3) movement in unplanned standards at ±5%.
- Implementing a new 'extreme event' SAIDI standard, set at either 120 SAIDI minutes or 6 million customer interruption minutes, and excluding specified events that we consider are predominantly caused by external factors.

Unplanned SAIDI and SAIFI are assessed annually while the planned SAIDI and SAIFI are assessed at the end of the 5-year period. The quality standards for OtagoNet Joint Venture are presented in the following table.

Table 15: SAIDI and SAIFI Quality Standards/Limits

Measure	Class	1 year	5 years	Annual pro-rata	Extreme Event
SAIDI	Planned	-	2114.43	422.89	120 SAIDI
	Unplanned	160.35	-		
SAIFI	Planned	-	9.6212	1.9242	-
	Unplanned	2.4172	-		

3 The Network and Asset Base

Except for residential developments, incremental growth and business-as-usual network renewal, the network and assets are largely unchanged from the 2023-33 AMP.

The 2023-33 AMP describes the Network and Asset Base as follows:

OtagoNet Joint Venture (OJV) is the disclosing entity for the electricity lines businesses that convey electricity to much of rural Otago, areas of Frankton, part of Wanaka and part of Cromwell.

OJV's service coverage includes three geographically separate areas:

1) The rural Otago area is supplied from GXPs in Balclutha, Halfway Bush, and Naseby.
2) The Frankton/Lake Hayes area is supplied from Frankton GXP and small embedded networks north-east of Wanaka and on the north side of Cromwell.
3) The network also takes energy from three embedded generators; the Mount Stuart wind farm, and the Paerau and Falls Dam hydro schemes.

3.1 Network Configuration

The network configuration is described in the following paragraphs.

The OJV asset base can be summarised as per the following table.

Table 16: OJV Asset Base Quantities

Asset Class	Group	Total number in OJV	Total number in LLN
Distribution Transformer	OH (Up to 100kVA)	4,068	0
Distribution Transformer	UG (up to 1MVA) + Platform	247	92
Power Transformer	1-4MVA	30	0
Power Transformer	4-8MVA	10	0
Power Transformer	8-16MVA	2	2
Power Transformer	> 16MVA	0	0
Overhead Switch	ABS	746	0
Overhead Switch	LBS (Solid Mould)	7	0
Protection Relay	G1 - Substation	216	10
Protection Relay	G2 - Field	19	0
Battery	G1 - Substation	85	2
Battery	G2 - Field	35	0
Distribution Earth	G1	4,870	93
RMU	Oil + Solid Insulation	11	80

Asset Class	Group	Total number in OJV	Total number in LLN
RMU	Gas Insulation	0	0
Metalclad Switchgear	All	9	1
Field CB	Field	38	0
Field CB	Zone	108	0
Poles	Wood	14,896	0
Poles	Concrete/steel	34,705	0
Cables	HV Cable XLPE	19	6
Cables	HV Cable Oil Pressurised	0	0
Cables	MV Cable XLPE / PVC	89	49
Cables	MV Cable PILC	4	1
Cables	LV Cable < 1000V	115	55
Instrument Transformers	VT	84	0
Instrument Transformers	CT	134	0
Neutral Earthing Resistor	Zone Subs	9	1
Regulators	Zone Subs	40	0
VRR	All	68	2
PLC	All	0	0
Injection Station	All	4	0
Capacitor Banks	All	0	0
CT-VT Units	Field	1	4
CT-VT Units	Zone	0	0
Generators	network-owned, <=600kVA	1	0
LV Outdoor Cubicles	All	684	2,081
OHL	km	4,413	0
Statcom	All	2	0
Battery Chargers	Zone	68	2
Battery Chargers	Field	0	0
Fibre	All	0	0
Fault Indicator	All	1	0
Power Supply	All	56	1
RTU	Zone	40	1
RTU	Field	45	0
Earth Mat	Zone	34	1
Earth Mat	Field (regulator site)	9	0
Fault Throw Switch	All	0	0
Oil Separator	All	0	0
Surge Diverter	Zone	696	1
Surge Diverter	Field	78	1
Zone Substation	Buildings	39	1

Bulk Supply Points and Embedded Generation

The OJV network is supplied by three Transpower GXPs:

- Balclutha GXP is supplied by a double circuit tower 110 kV diversion (not a tee) from the Gore – Berwick single circuit 110 kV pole line. Supply is taken through eight 33kV feeders from the GXP.
- Naseby GXP is supplied off a single circuit 220 kV tower line from Roxburgh to Livingstone and supplies the Ranfurly zone substation via two 33 kV feeders.
- Halfway Bush is a strong point in the 220/110 kV grid; tied to South Dunedin, Three Mile Hill, Berwick, and the Roxburgh power station. Halfway Bush feeds two OJV-owned 33 kV circuits heading north along the coast from Dunedin to Palmerston, as well as supplying power at 33 kV to Aurora's western Dunedin network.

The Frankton network is supplied by one Transpower GXP:

- Frankton GXP is supplied off a dual circuit 110 kV spur from Cromwell and supplies the Remarkables zone substation via two 33 kV feeders. Frankton GXP also supplies the Aurora network (Queenstown, Arrowtown, and the remaining Frankton areas).

Embedded in the Otago network are three generators with capacity greater than 1 MW:

- The 12.25 MW Paerau hydro scheme was built by Otago Power Limited in 1984 and then sold to Trustpower as a result of the enactment of the Electricity Industry Reform Act 1998. Paerau's generation is injected into the Ranfurly zone substation at 66kV and is embedded with the Oceana Gold's Macraes Flat mine load.
- The Pioneer Generation Limited (PGL) 1.25 MW Falls Dam hydro scheme is connected to the 33kV network at Oturehua. PGL owns the equipment to enable connection onto the OtagoNet 33kV line.
- The Southern Generation Limited Partnership (SGLP) 8.0 MW Mount Stuart wind scheme is connected to the 33kV network on the Glenore-Lawrence line. SGLP owns the equipment to enable connection onto the OtagoNet 33kV line.

Table 17: Bulk Supply Characteristics

Supply	Voltage	Rating	Firm Rating	Maximum Demand 2021/22	LSI* Coincident Demand 2021/22
Balclutha	110/33 kV	60 MVA	37 MVA	29.2 MW (08:00 27/05/21)	27.4 MW (08:00 15/10/20)
Naseby	220/33 kV	80 MVA	53 MVA	30.0 MW 15:00 13/01/22)	21.8 MW (08:00 15/10/20)
Halfway Bush	220/33 kV	220 MVA	124 MVA	7.7 MW (08:00 15/09/21)	5.6 MW (08:00 15/10/20)
Frankton	110/33 kV	151 MVA	79 MVA	9.7 MW (08:00 01/07/21)	6.6 MW **(08:00 15/10/20)**

Supply	Voltage	Rating	Firm Rating	Maximum Demand 2021/22	LSI* Coincident Demand 2021/22
Paerau Generation	66 kV	30 MVA	15 MVA[1]	15.6 MW (09:00 08/09/21)	4.1 MW (08:00 15/10/20)
Falls Dam Generation	33 kV	1.25 MVA	2 MVA[1]	1.3 MW (01:00 15/02/22)	1.3 MW (08:00 15/10/20)
Mount Stuart Generation	33 kV	8 MVA	9 MVA[1]	8.1 MW (00:00 26/01/22)	0.1 MW (08:00 15/10/20)

*LSI = Lower South Island. The LSI peak demand is calculated each year for the period between 1 September and 31 August.

In addition, a small number of distributed generation connections exist but are only a few kW each in size. These generators are generally domestic solar installations which due to their generation profiles (tied to sunlight conditions) have negligible effect on GXP loading.

Subtransmission Network

The Otago subtransmission network comprises two electrically separate networks as depicted in Figure 16. The subtransmission network comprises 74 km of 66 kV line and 636 km of 33 kV line with the following characteristics:

- It is almost totally overhead except for short cable runs at GXPs and zone substations.
- It is almost totally radial except for a few instances on the South Otago network where closed rings have been formed, and the Palmerston area where an open ring is operated.
- It includes a large number of lightly loaded zone substations because the long distances are beyond the reach of 11 kV.

The Otago subtransmission network is different to most other electricity distribution businesses in that it has very little redundancy because of the low load density; large parts of the network may be essentially characterised as 33 kV feeders. This arrangement impacts on reliability as 33 kV line faults result in larger customer outages. This focuses asset management on the condition and integrity of these lines. As poor condition lines are rebuilt, they are generally replaced with concrete poles and clamp-top insulators to maximise reliability and life. Galvanised steel crossarms have been used in some line builds and fibreglass crossarms are also being trialled.

The subtransmission circuits are generally unregulated and of a capacity specifically chosen for the anticipated load. The dominant design parameters are voltage drop and losses, as almost exclusively the current loading is well below the thermal capacity of the conductor. 33 kV regulators are needed on the OtagoNet system in places where the subtransmission system is also used as distribution. On a voltage and loss basis most circuits operate between 80% and 150% of optimum level.

Most subtransmission line circuits are routed cross-country to minimise cost and length. More recent circuits tend to be constructed along road reserves due to the nature of legislation. Poles are a mixture

[1] This firm rating is based on the number and capacity of the transformers onsite, however it should be noted that these sites are connected to the network via a single supply route.

of concrete, hardwood and softwood, chosen by the relative economics at the time of construction. Rural lines are typically sagged to a maximum operating temperature of 50°C to minimise the installation (capital) cost.

The Frankton subtransmission network comprises 6km of 33 kV underground cable connecting the Remarkables substation to the Frankton GXP, configured as dual redundant feeders.

A map and single line diagram of the subtransmission network is available from PowerNet on request (email: amp@powernet.co.nz).

Figure 20: Subtransmission Network

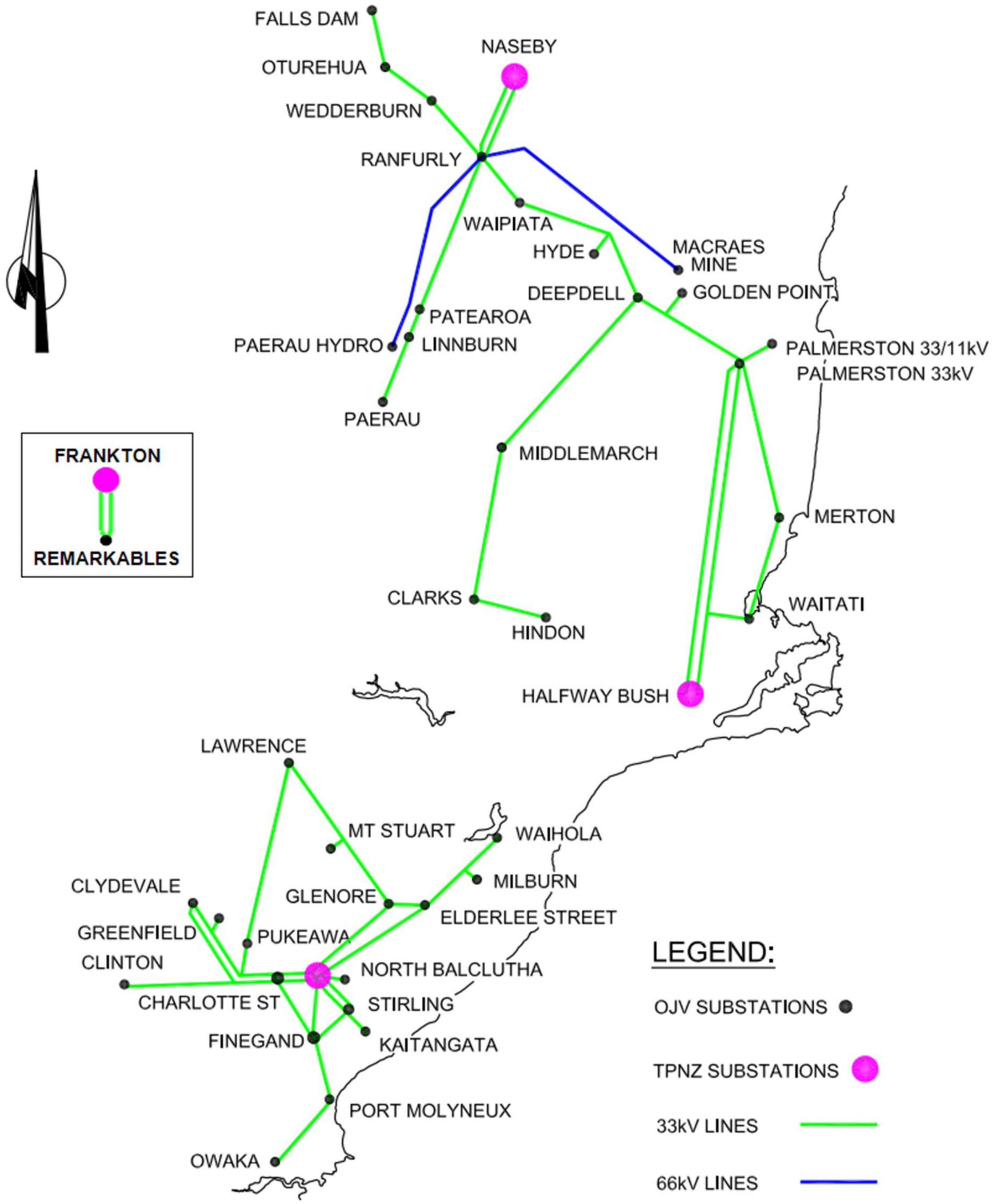


Figure 21: Subtransmission Poles

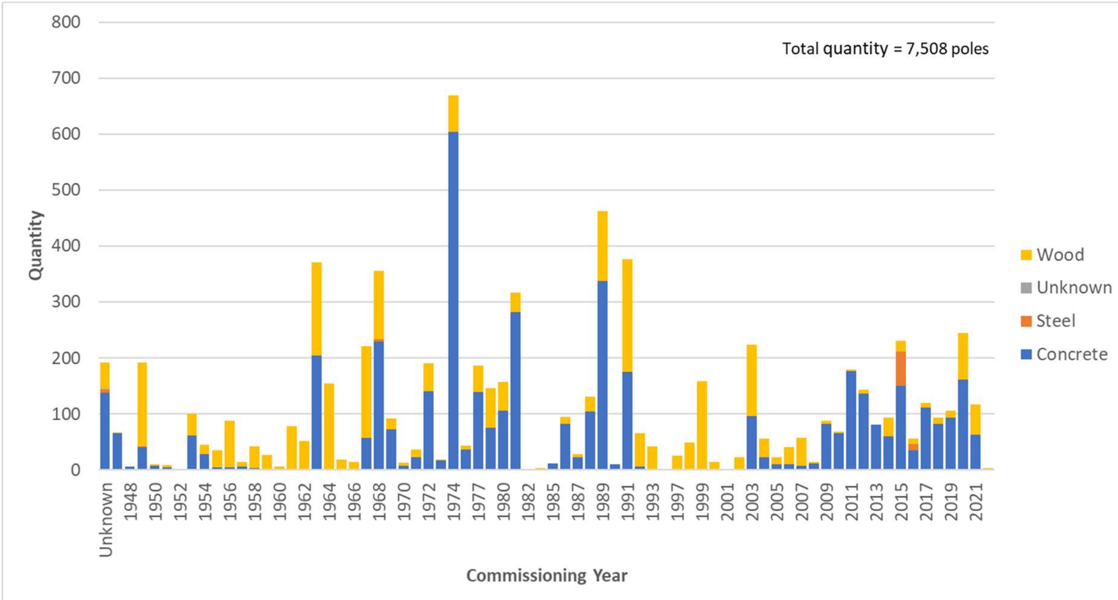


Figure 22: Subtransmission Conductor

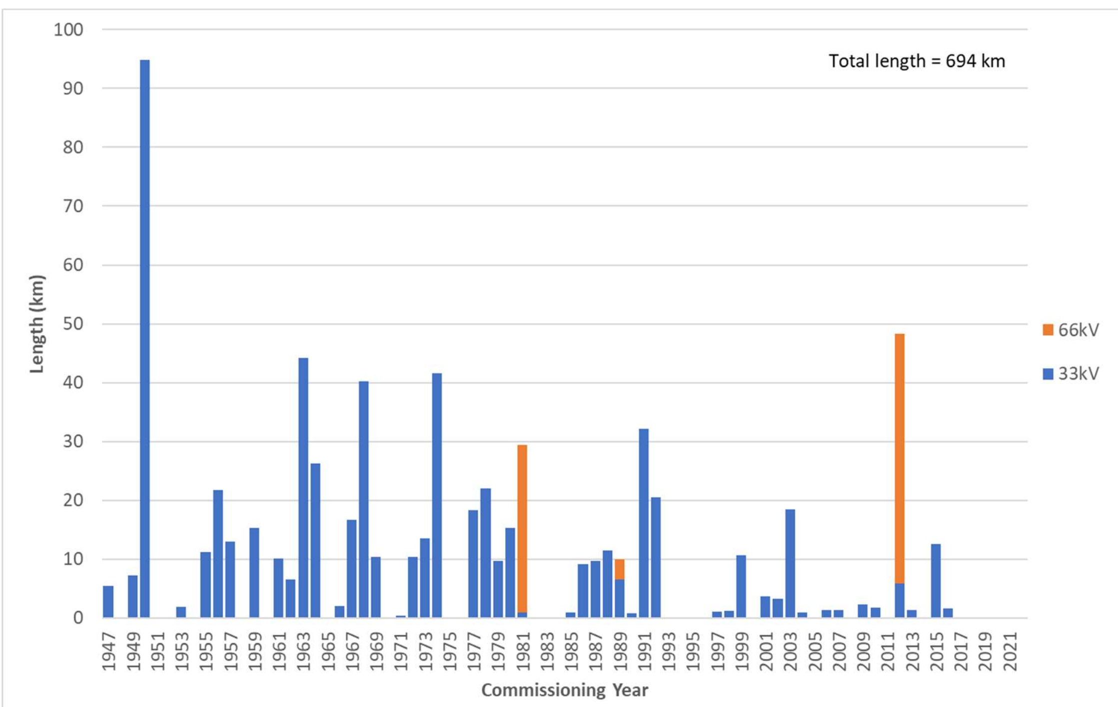
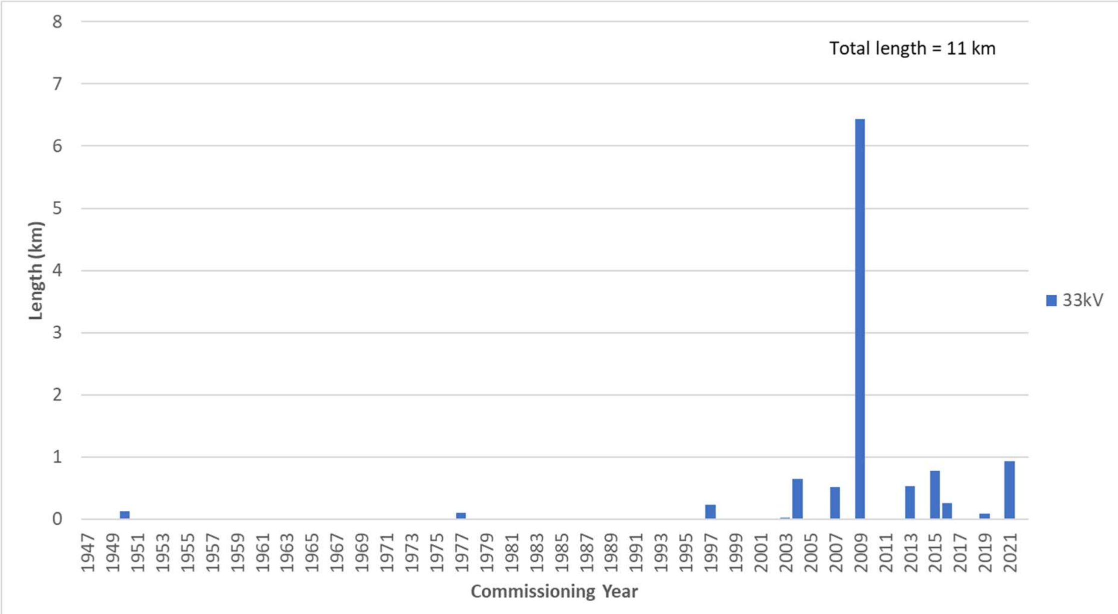


Figure 23: Subtransmission Cable



Zone Substations

The Otago network has 32 zone substations, with a 66/33 kV interconnecting station at Ranfurly. Additionally in Otago, there are seven 33/0.415 kV distribution transformers supplied direct off the 33 kV subtransmission network at Balmoral Water Scheme, Anderson, Hore's Pump, O'Malley's House, O'Malley's Pump, Rough Ridge and Tisdall; a site at Mount Stuart where a wind generator's connection is made at 33 kV; and dairy plant at Greenfield where the supply assets comprise a 33 kV regulator and five 33/0.415 kV transformers.

The Frankton network has one 33/22 kV zone substation (Remarkables).

Descriptions for OJV's zone substations are provided in Table 18.

Table 18: Zone Substations

Substation	Nature of load	Description of Substation	Minimum Supply Security Required	Actual Supply Security
Charlotte Street (Balclutha)	Urban, domestic, and commercial with some rural farms	Dual 33kV supply to a 33kV indoor switchboard, with three 33kV feeders. Dual 5MVA transformers, 11kV indoor switchboard	AA	AAA
Clarks	Remote isolated rural farms	Tee off the 33kV radial line beyond Middlemarch. 0.5MVA 22kV SWER substation.	A(ii)	A(ii)
Clinton	Small urban township and rural farms	Radial 33kV from Clifton switches. 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)

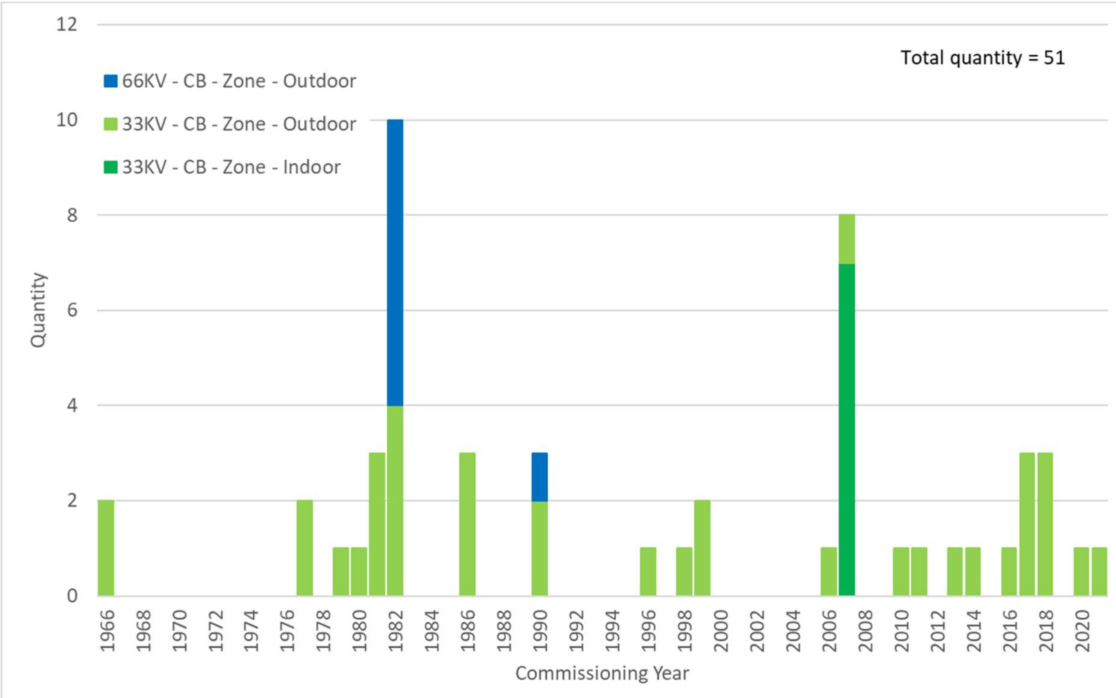
Clydevale	Small urban township and rural farms	Two supply routes at 33kV. 5MVA transformer and indoor 11kV substation.	A(i)	A(ii)
Deepdell	Remote isolated rural farms	Alternate 33kV lines supplying 0.75MVA transformer and basic 11kV outdoor substation.	A(ii)	A(ii)
Elderlee Street (Milton)	Urban domestic and commercial with some rural loads including farms and timber mills	Supplied off a 33kV ring. Dual 5MVA transformers and an 11kV indoor switchboard.	A(i)	A(i)
Finegand	Rural farming Meat processing plant	Three supply routes at 33kV. 2.5MVA transformer and outdoor 11kV substation. A 33kV feeder to a meat processing plant.	A(i)	A(ii)
Glenore	Rural farming	Supplied off a 33kV ring. 1.5MVA transformer and outdoor 11kV substation.	A(ii)	A(ii)
Golden Point	Mining	Teed off the Palmerston to Deepdell 33kV line. 5MVA transformer with indoor 11kV switchgear.	A(i)	A(ii)
Hindon	Remote isolated rural farms	Radial 33kV line to 0.5MVA 22kV SWER and 0.1MVA 11kV substation.	A(ii)	A(ii)
Hyde	Rural farming with irrigation load	Alternate 33kV lines and a short 33kV spur line to a 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Kaitangata	Small urban township and rural farms	Radial 33kV to a 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Lawrence	Small urban township and rural farms	Alternate 33kV lines to a 2.5MVA transformer and indoor 11kV substation.	A(i)	A(ii)
Linnburn	Rural farming with irrigation	Temporary substation teed off radial 33kV line to Paerau. 1 MVA transformer and single feeder.	A(ii)	A(ii)
Merton	Urban domestic and commercial with some rural farms and one large chicken farm	Teed off the radial 33kV Palmerston to Waitati. Dual 2.5MVA transformers and outdoor 11kV substation.	A(i)	A(ii)
Middlemarch	Small urban township and rural farms	Radial 33kV from Deepdell to 2.5MVA transformer and outdoor 11kV substation.	A(ii)	A(ii)
Milburn	Sawmills and some rural load	Teed off the Elderlee to Waihola 33kV line. 3/5MVA transformer with standby 2.5MVA transformer and indoor 11kV switchgear.	A(i)	A(ii)
North Balclutha	Urban domestic and commercial with some rural	33kV line from Balclutha GXP. 5MVA transformer and outdoor 11kV substation.	A(i)	A(i)
Oturehua	Rural farming	Teed off the radial 33kV from Ranfurly to Falls Dam generation. 0.75MVA transformer, outdoor 11kV substation and 33kV regulator for generator connection.	A(ii)	A(ii)
Owaka	Small urban township and rural farms	Radial 33kV line from Finegand. 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Paerau	Remote isolated rural farms and irrigation	Radial 33kV from Ranfurly. 1MVA transformer and basic 11kV substation.	A(ii)	A(ii)
Paerau Powerhouse	12.25MW hydro generation station	Radial 66kV line from Ranfurly. Dual 7.5M/15VA 66/11kV transformers with 66kV switchyard; the indoor 11kV switchboard is owned and operated by the generator.	AAA	A(ii)

Palmerston	Urban domestic and commercial with some rural farms and timber mills	Radial 33kV to dual 2.5MVA transformers and outdoor 11kV substation.	A(i)	A(ii)
Patearoa	Rural farming with irrigation	Teed off radial 33kV line to Paerau, 2.5MVA transformer and outdoor 11kV substation with 33kV regulator for the Paerau line.	A(i)	A(ii)
Port Molyneux	Small seaside township and rural farms	Teed off radial 33kV line to Owaka. 2.5MVA transformer and outdoor 11kV substation.	A(ii)	A(ii)
Pukeawa	Rural farming	Alternate 33kV lines to a 0.75MVA transformer and basic 11kV substation.	A(ii)	A(ii)
Ranfurly 66/33kV	Mine and hydro generation (66kV). Urban domestic and commercial with some rural farms and irrigation (33kV)	Dual heavy 33kV lines from Naseby GXP to 33/11kV substation and dual 12.5/25MVA 33/66kV transformers, outdoor 66kV structure with two feeders.	AAA	AAA
Ranfurly 33/11kV	Urban domestic and commercial with some rural farms and irrigation	Single 33kV line from 66/33kV substation, a single 2.5MVA transformer and a 2.5MVA standby transformer, and an outdoor 11kV substation.	A(i)	A(ii)
Remarkables	Urban domestic and commercial	Dual 33 kV cables from Frankton GXP to dual 12.5/23 MVA transformers and indoor 22 kV switchroom.	A(i)	AAA
Stirling	Fonterra Stirling Cheese Factory	33kV line and cable switchable between two 33kV lines from Balclutha GXP. 5MVA transformer and 11kV indoor switchboard.	A(i)	A(ii)
Waihola	Small urban township and rural farms	Radial 33kV line off the 33kV ring that supplies Elderlee Street and Glenore. 1.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Waipiata	Rural farming with irrigation	33kV tee off the 33kV line from Ranfurly to Deepdell. 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Waitati	Small urban townships and rural farms	Radial 33kV line from Palmerston and a tee-off from the Halfway Bush-Palmerston 33kV line. 2.5MVA transformer and outdoor 11kV substation.	A(i)	A(ii)
Wedderburn	Rural farming	Teed off the 33kV line from Ranfurly to Falls Dam. 1MVA transformer and outdoor 11kV substation.	A(ii)	A(ii)

Subtransmission Voltage Switchgear

Charlotte Street substation has an indoor 33 kV Schneider switchboard, and the Remarkables substation utilises the breakers at the Frankton GXP. The remaining 33 kV and 66 kV circuit breakers on the network are outdoor units mounted on stands in conjunction with associated current transformers. Oil, vacuum and SF6 units are in use. Ratings vary from 200 A to 2000 A, although load is typically in the range of 20A to 630A.

Figure 24: Zone Substation Subtransmission Voltage Circuit Breakers



Power Transformers

Table 19: Power Transformers

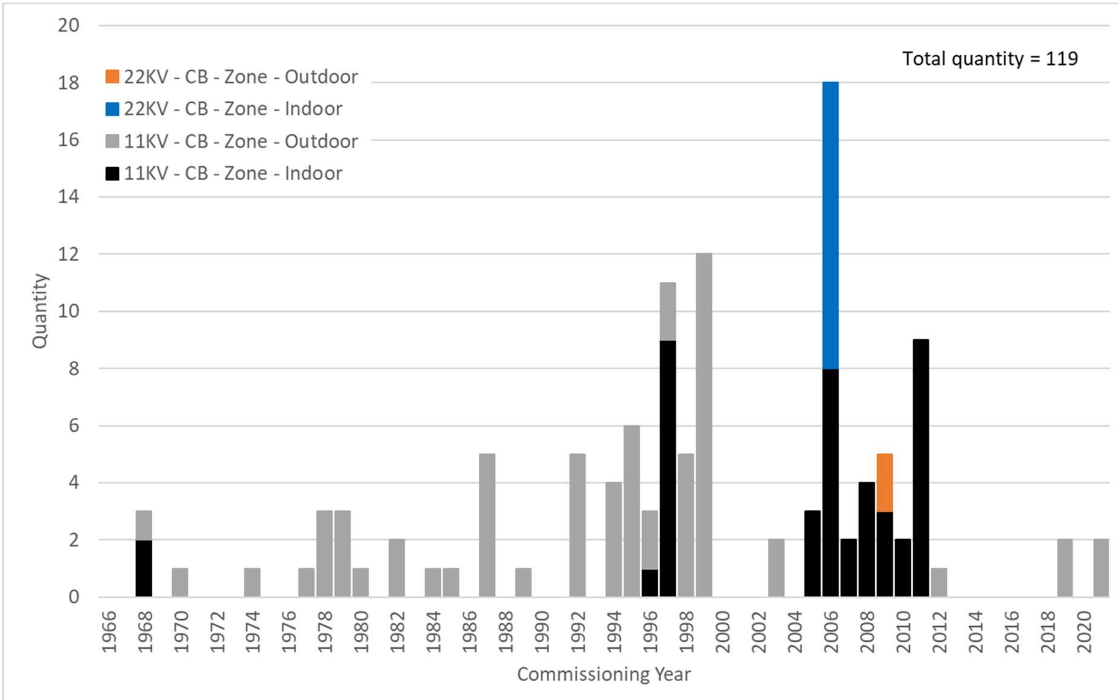
Transformer Location	Rating	Installed	Remaining Life
Charlotte Street T1	5 MVA	1974	17
Charlotte Street T2	5 MVA	1974	17
Clinton T1	2.5 MVA	2012	55
Clarks Junction T1	0.5 MVA	1958	1
Deepdell T1	0.75 MVA	1973	16
Elderlee Street T1	5 MVA	1974	17
Elderlee Street T2	5 MVA	1974	17
Finegand T1	2.5 MVA	1963	6
Glenore T1	1.5 MVA	1957	0
Golden Point T1	1.5 MVA	1962	5
Hindon T1	0.1 MVA	1987	30
Hindon T3	0.5 MVA	1967	10
Hyde T1	2.5 MVA	1973	16
Kaitangata T2	2.5 MVA	2006	49
Lawrence T1	2.5 MVA	2009	52
Linnburn T1	1 MVA	1997	40
Merton T1	2.5 MVA	1967	10

Transformer Location	Rating	Installed	Remaining Life
Merton T2	2.5 MVA	1967	10
Middlemarch T1	2.5 MVA	1979	22
Milburn T1	3 MVA	2011	54
Milburn T2	2.5 MVA	1960	3
North Balclutha T1	5 MVA	1987	30
Clydevale T2	5 MVA	2015	58
Oturehua T1	0.75 MVA	1967	10
Owaka T1	2.5 MVA	1968	11
Paerau T1	1 MVA	2011	54
Palmerston T1	2.5 MVA	2006	49
Palmerston T2	2.5 MVA	2006	49
Patearoa T1	2.5 MVA	1960	3
Pukeawa T1	0.75 MVA	1990	33
Port Molyneux T1	2.5 MVA	2006	49
Paerau Powerhouse T1	7.5 MVA	1982	25
Paerau Powerhouse T2	7.5 MVA	1982	25
Ranfurly T1	12.5 MVA	1983	26
Ranfurly T2	12.5 MVA	1983	26
Ranfurly T3	2.5 MVA	2012	55
Ranfurly T4	2.5 MVA	2007	50
Remarkables T1	12.5 MVA	2006	49
Remarkables T2	12.5 MVA	2006	49
Stirling T1	5 MVA	1987	30
Waitati T1	2.5 MVA	1965	8
Wedderburn T1	1 MVA	2011	54
Waihola T1	1.5 MVA	1993	36
Waipiata T1	2.5 MVA	2011	54

Distribution Voltage Switchgear

OJV substations have predominantly outdoor distribution-voltage switchgear, although the number of indoor switchboards is increasing as they present a seismically strong and deterioration-resistant alternative to outdoor switchgear.

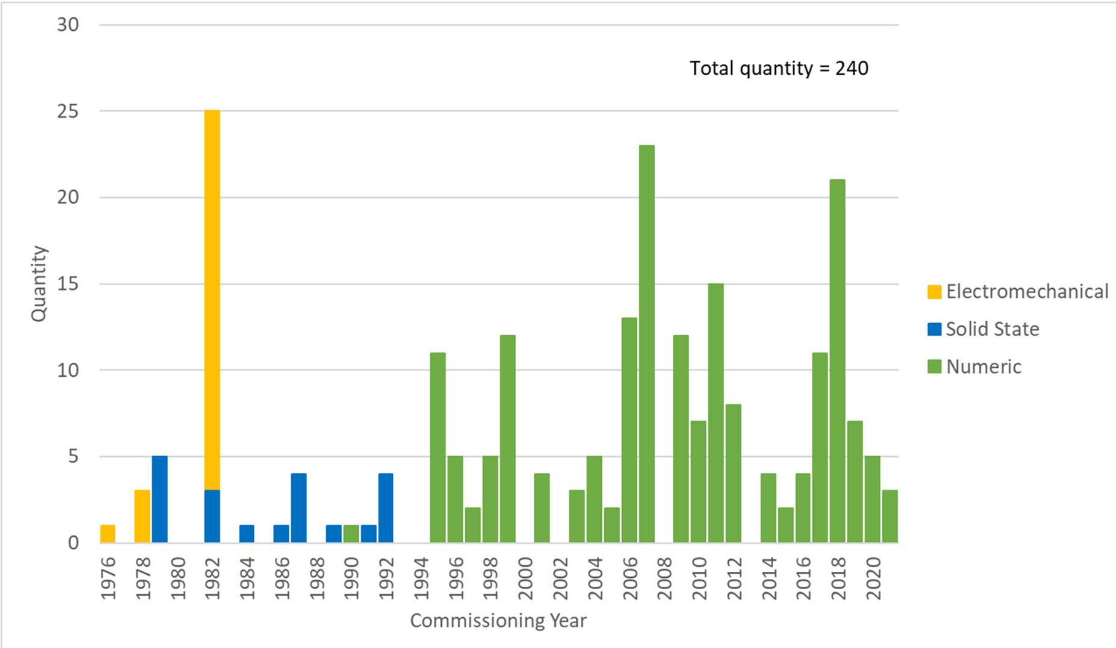
Figure 25: Zone Substation Distribution Voltage Circuit Breakers



Protection Equipment

OJV's protection relays' age profile by type is shown in Figure 26 below.

Figure 26: Protection Relays



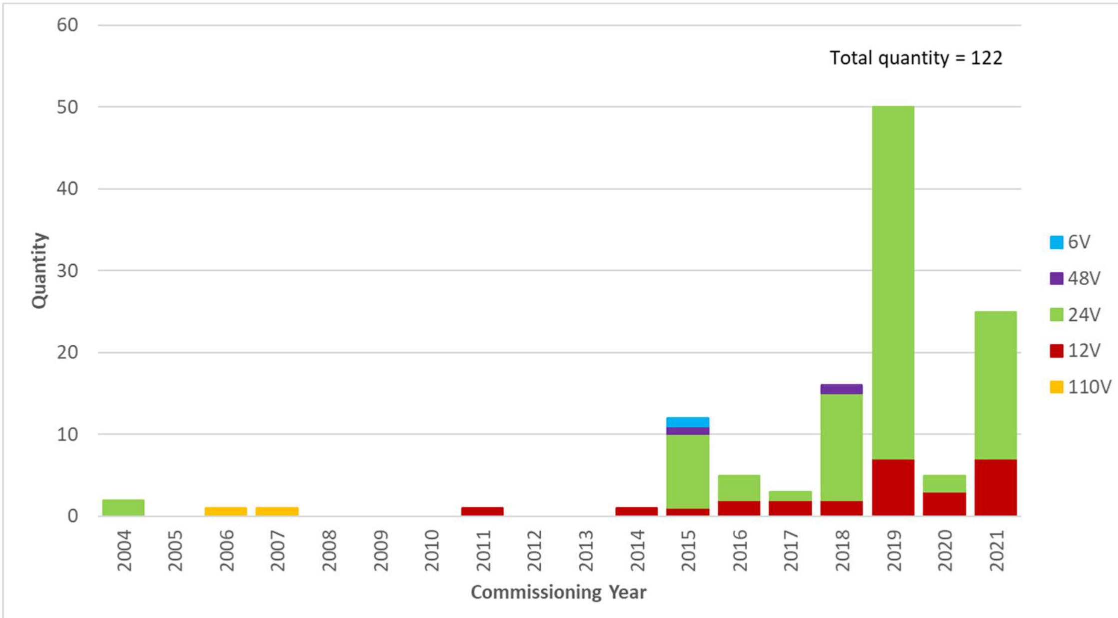
The protection relays are predominantly numeric types which are inherently self-monitoring. A number of solid state (analogue electronic) relays are present mainly functioning as distribution feeder relays, they will be phased out either when the existing outdoor switchgear is replaced with new indoor switchboards and protection, or by routine replacement.

The older electromechanical relays are located at Ranfurly and Paerau Powerhouse substations, they will be replaced with numeric relays within three years.

DC Power Supplies

Batteries are essential to the safe operation of protection devices. Therefore, regular checks are performed and smaller batteries are replaced prior to the manufacturer's recommended life. The service life of larger battery banks may be extended if regular condition monitoring indicates continued good asset health and storage capacity.

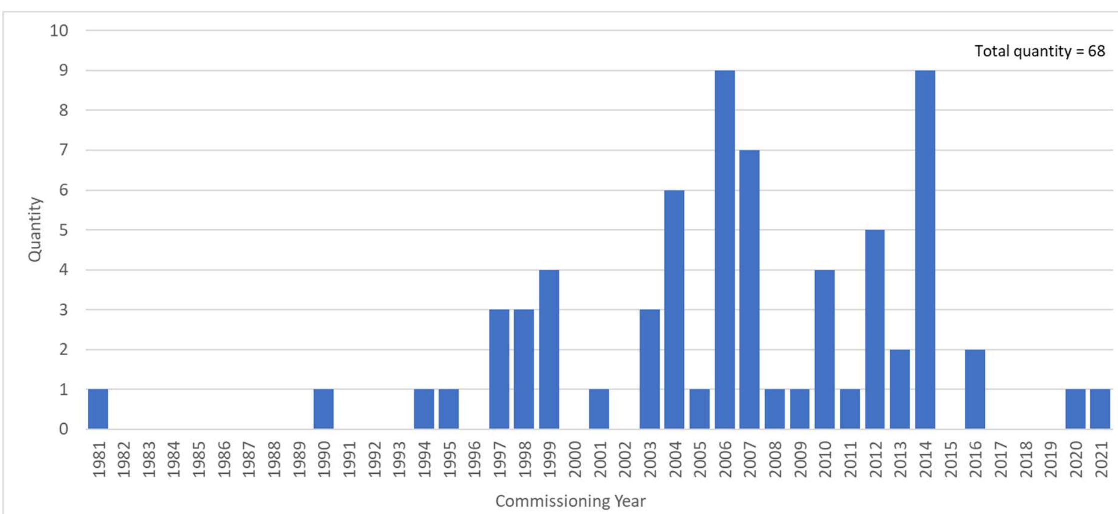
Figure 27: Batteries



Tap Changer Controls

Voltage regulating relays are installed with their associated transformers. Replacements will coincide with transformer replacements or when the control is approaching its end of useful life. Unexpected failures may require replacement with the modern voltage regulating relay standardised solution based on an SEL controller.

Figure 28: Tap Changer Controls

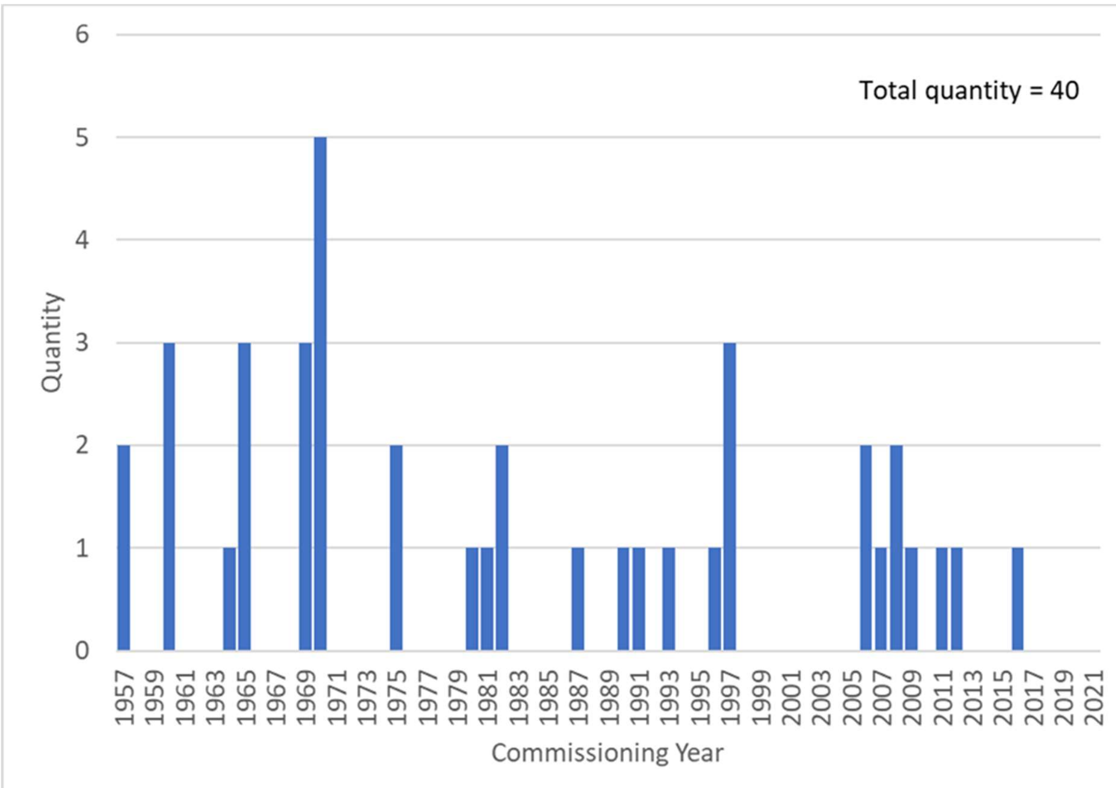


Substation Buildings

Substation buildings house protection and control equipment and in the case of indoor switchboards, the substation high voltage switchgear.

Seismic strengthening remedial work has been carried out on a number of substation buildings. Ten buildings will be replaced during the ten year planning period when outdoor structures are replaced with seismically resilient indoor switchboards.

Figure 29: Zone Substation Buildings



Distribution Network

In rural areas of the Otago network the configuration is almost totally radial with little interconnection.

Table 20: Distribution network per substation

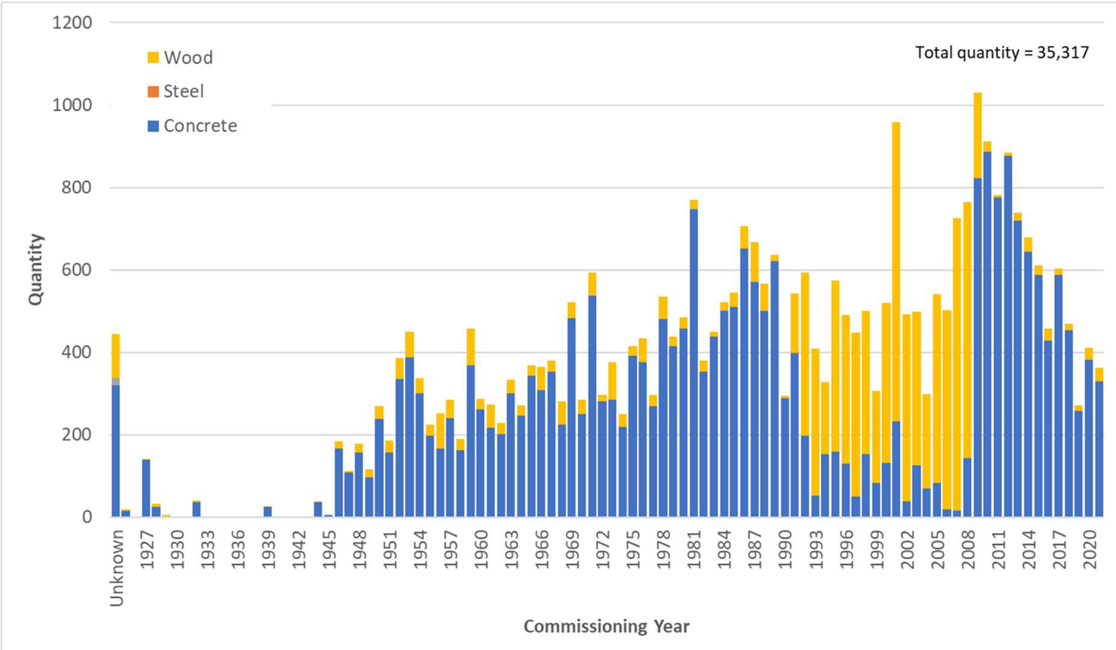
Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Becks	26.4	0.0	31	1.2/km
Brothers Peak	2.2	0.0	2	0.9/km
Charlotte Street	71.3	1.6	1,614	22.1/km
Clarks	134.4	0.0	172	1.3/km

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Clinton	283.4	1.9	754	2.6/km
Clydevale	276.8	2.7	632	2.3/km
Craiglynn Station	3.4	0.0	5	1.5/km
Deepdell	49.9	0.3	90	1.8/km
Elderlee	149.3	1.2	1,537	10.2/km
Finegand	103.1	0.8	297	2.9/km
Glenore	93.5	0.0	199	2.1/km
Golden Point	0.1	0.02	1	8.2/km
Hills Creek	11.8	0.0	17	1.4/km
Hindon	116.6	0.0	130	1.1/km
Hyde	37.6	0.0	66	1.8/km
Kaitangata	95.4	0.0	631	6.6/km
Lawrence	179.7	2.3	735	4.0/km
Linnburn	35.3	0.9	44	1.2/km
Merton	108.0	2.1	1,469	13.3/km
Middlemarch	120.0	1.2	344	2.8/km
Milburn	39.9	0.7	110	2.7/km
North Balclutha	119.4	2.3	1,263	10.4/km
Oturehua	28.4	0.3	93	3.2/km
Owaka	276.5	1.6	946	3.4/km
Paerau	27.2	0.0	40	1.5/km
Palmerston	168.4	1.3	1,045	6.2/km
Patearoa	56.5	4.0	164	2.7/km
Port Molyneux	37.3	0.2	406	10.8/km
Pukeawa	45.1	0.5	76	1.7/km
Ranfurly	203.7	5.4	1,219	5.8/km
Redbank	2.9	0.0	4	1.4/km
Remarkables	0.0	45.8	3,015	65.8/km
Stirling	0.0	1.0	1	1.0/km
Stoneburn	30.5	0.0	28	0.9/km
Waihola	92.2	2.8	710	7.5/km
Waipiata	90.4	1.4	204	2.2/km
Waitati	67.1	6.8	1,101	14.9/km
Wedderburn	34.5	1.3	51	1.4/km
Wanaka	0.0	2.9	573	194.5/km
Total/average	3,218	93.6	19,819	6.0/km

Overhead Distribution

OJV's overhead distribution network uses a mix of concrete and wood poles as shown in Figure 30.

Figure 30: Distribution Poles



The nominal life of poles varies with pole type, 45 years for wood poles and 60 years for concrete. Industry experience has shown that poles can last substantially longer than nominal life, therefore condition-based replacement is more appropriate than age-based replacement. The replacement and renewal programme is based on a five-yearly condition assessment carried out on all distribution lines.

Figure 31: Distribution Overhead Line Conductors

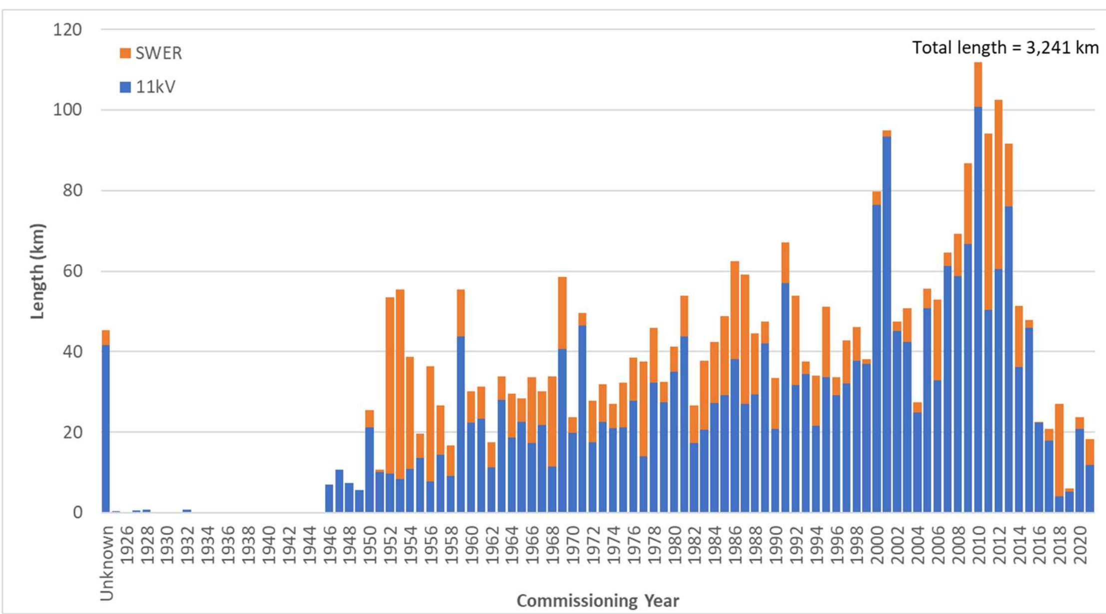
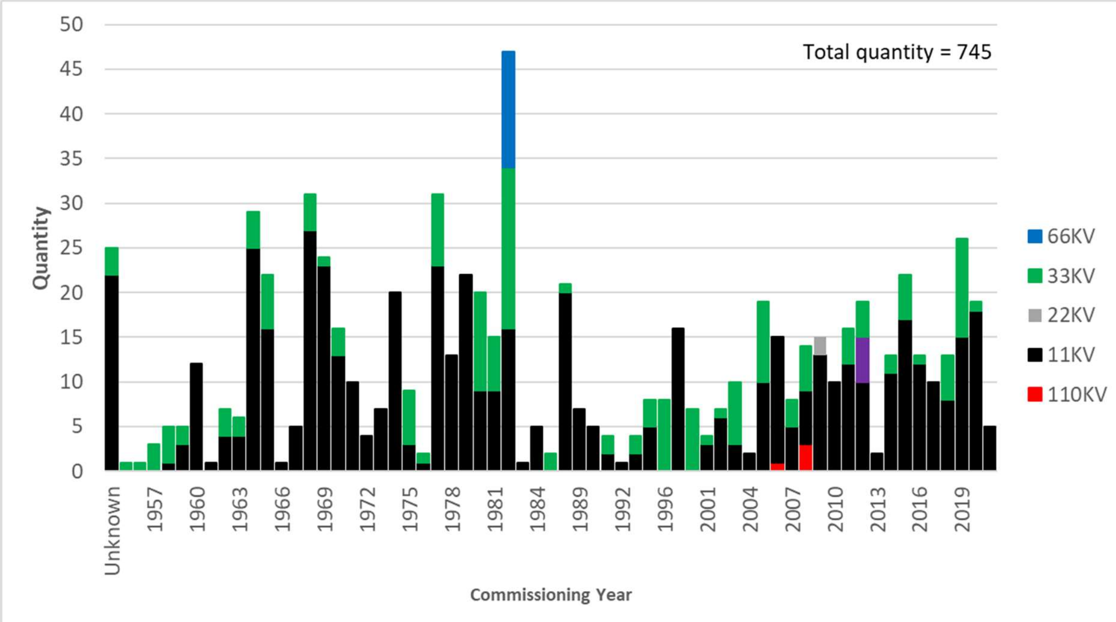


Figure 32 shows the number of Air Break Switches by commissioning year.

Figure 32: Air Break Switches



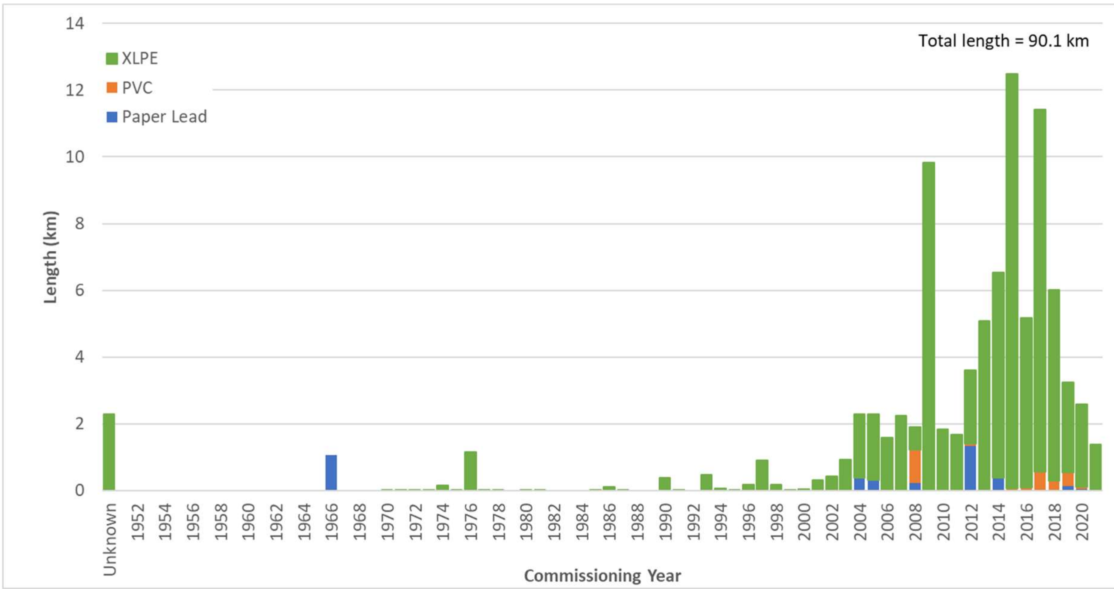
Underground Distribution

The Otago area networks are predominately overhead distribution with limited short lengths of 11 kV cable being installed in recent years. The Frankton area network is entirely underground, mostly 22 kV cable with a small amount of 11 kV near Shotover Park.

Failure of cable is relatively rare. The most common failure modes are joints, terminations, lightning and external mechanical damage.

The distribution cable age profile is shown in Figure 33.

Figure 33: Distribution Cables (11kV & 22kV)



Distribution Substations

Just as zone substation transformers form the interface between the subtransmission and the 11kV and 22kV distribution networks, distribution substations form the interface between the 11kV and 22kV distribution and 400V distribution networks. The distribution substations range from 1 kVA pole-mounted transformers to 3-phase 1,500kVA ground-mounted transformers.

Distribution Transformers

Each distribution transformer has medium voltage (MV) protection, usually provided by fuses, although some larger units are protected by circuit breakers with basic overcurrent and earth fault relays. Low voltage protection is by the DIN[2] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

Table 21 shows the number of distribution transformers by size on OJV's network. Transformers larger than 100kVA are installed at ground level.

Table 21: Number of distribution transformers

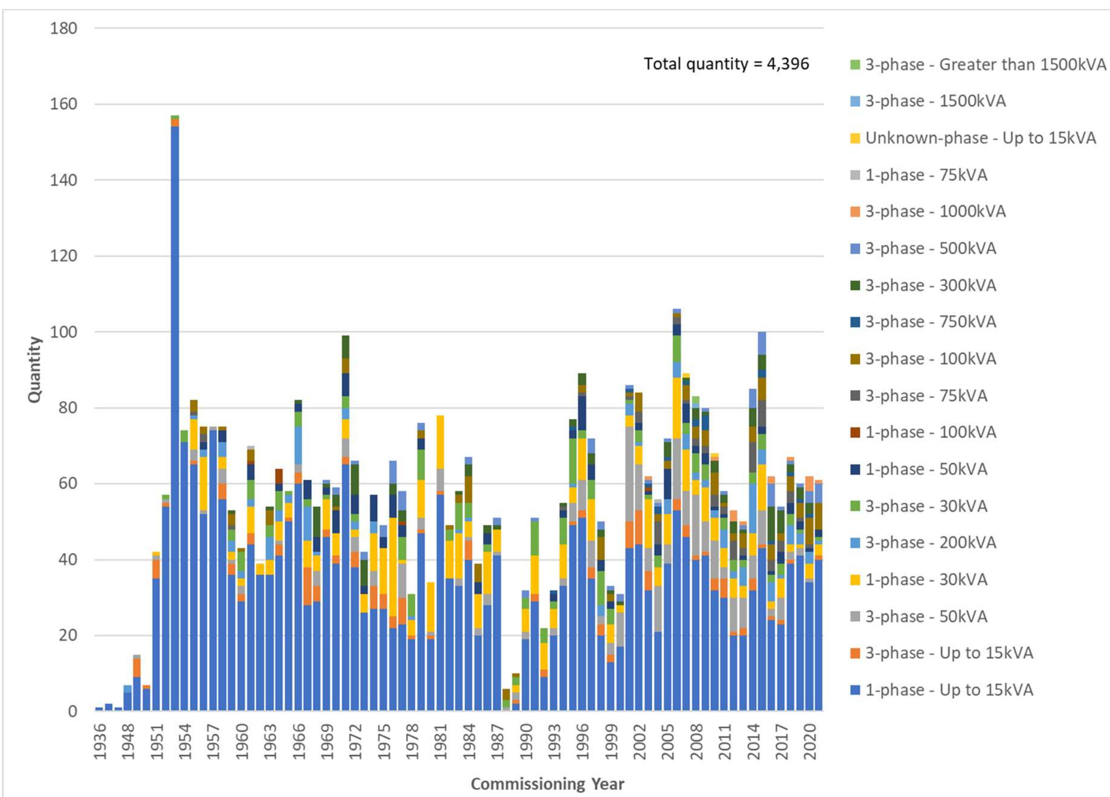
Phases	Rating	Pole Mount	Ground Mount
1 phase	up to 15 kVA	2648	16
	30 kVA	420	12
	50 kVA	133	6

[2] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization). This is Germany's national organisation for standardization and an ISO member body.

	75 kVA	2	-
	100 kVA	7	-
3 phase	up to 15 kVA	148	3
	30 kVA	180	8
	50kVA	263	10
	75 kVA	59	2
	100 kVA	95	31
	200 kVA	66	65
	300 kVA	32	80
	500 kVA	1	74
	750 kVA	-	20
	1,000 kVA	-	14
	1,500 kVA	-	1
Total		**4054**	**342**

Figure 34 provides an overview of the age profiles of distribution transformers. Transformers found to be in poor condition after five-yearly inspections will be replaced, sometimes with units removed from service and refurbished for reuse.

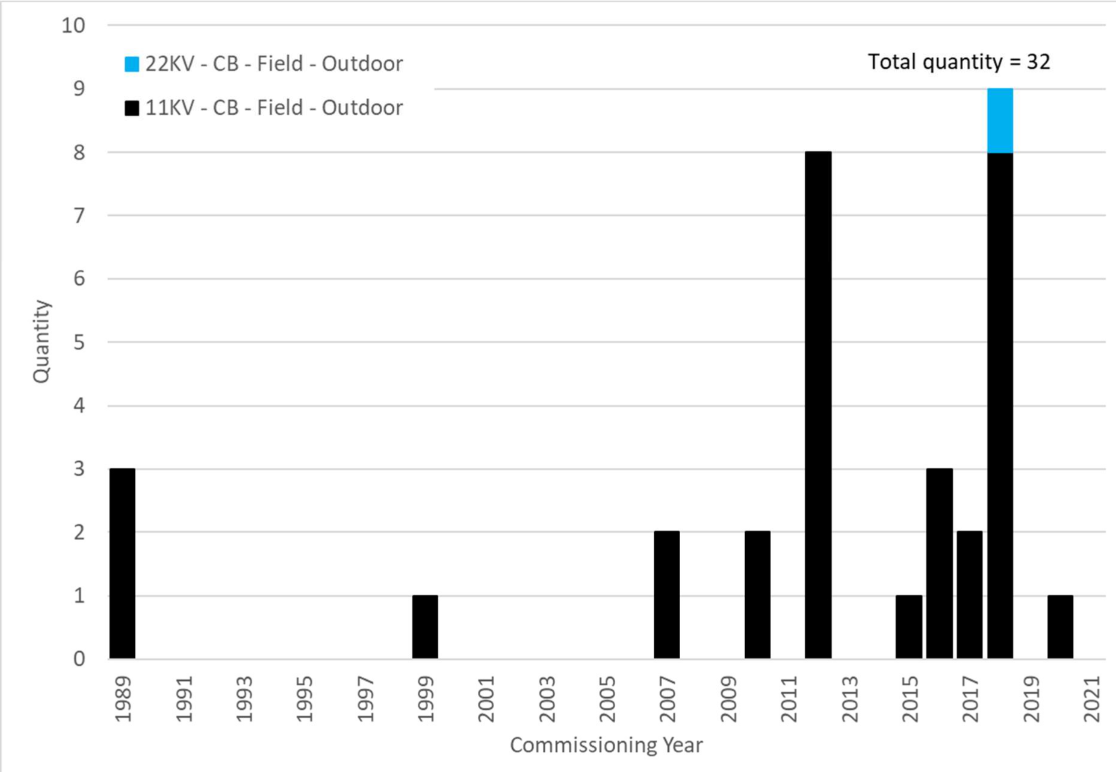
Figure 34: Age Profile of Distribution Transformers



Distribution Switchgear

OJV has a number of 11 kV outdoor circuit breakers installed on the distribution network to help improve reliability.

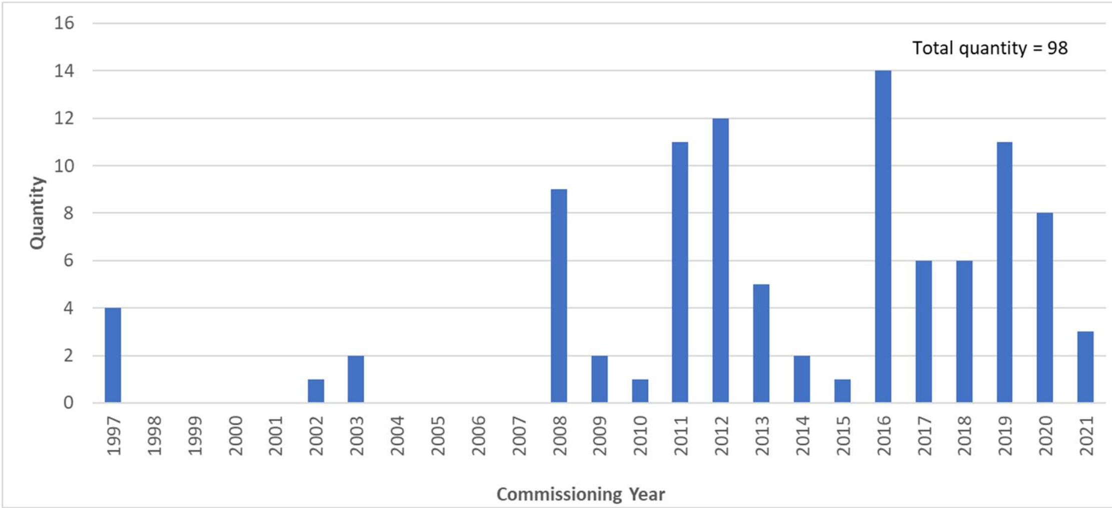
Figure 35: Field Circuit Breakers at Distribution Voltage



In addition there are approximately 550 Air Break Switches on the distribution network, together with around 2,400 individual 11 kV fuses. These items are visually inspected as part of routine line inspections. "Hot-spot" thermographic inspection may be carried out where there is reason to believe a switch might not be contacting properly.

The age profile of ring main units (RMUs) is displayed in Figure 36.

Figure 36: Age Profile of Ring Main Units



Operating restrictions are placed on some RMU equipment. This is to prevent risks and to manage hazards associated with oil filled switchgear (as identified by incidents occurring in the wider industry). A solution has been developed that allows safe operation of suitable models of equipment without compromising arc-flash boundaries.

Low Voltage Network

OJV's Low Voltage (LV) network (400/230 V) supplies its 18,881 customers. The proportions per substation of overhead and underground network, customer count and density are presented in Table 22.

Table 22: LV Network Characteristics per Substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Charlotte Street	27.9	5.8	1,614	47.9/km
Clarks	2.2	0.5	172	63.5/km
Clinton	12.8	0.2	754	58.0/km
Clydevale	8.2	0.5	632	72.5/km
Deepdell	2.7	0	90	33.3/km
Elderlee Street	36.7	2.0	1,537	39.7/km
Finegand	6.4	0.1	297	46.1/km
Glenore	2.7	0.5	199	62.2/km
Hindon	1.5	0.2	130	74.9/km
Hyde	1.7	0	66	39.1/km
Kaitangata	18.3	0.2	631	34.1/km
Lawrence	22.6	2.2	735	29.5/km
Linnburn	0.4	0.0	44	104.2/km

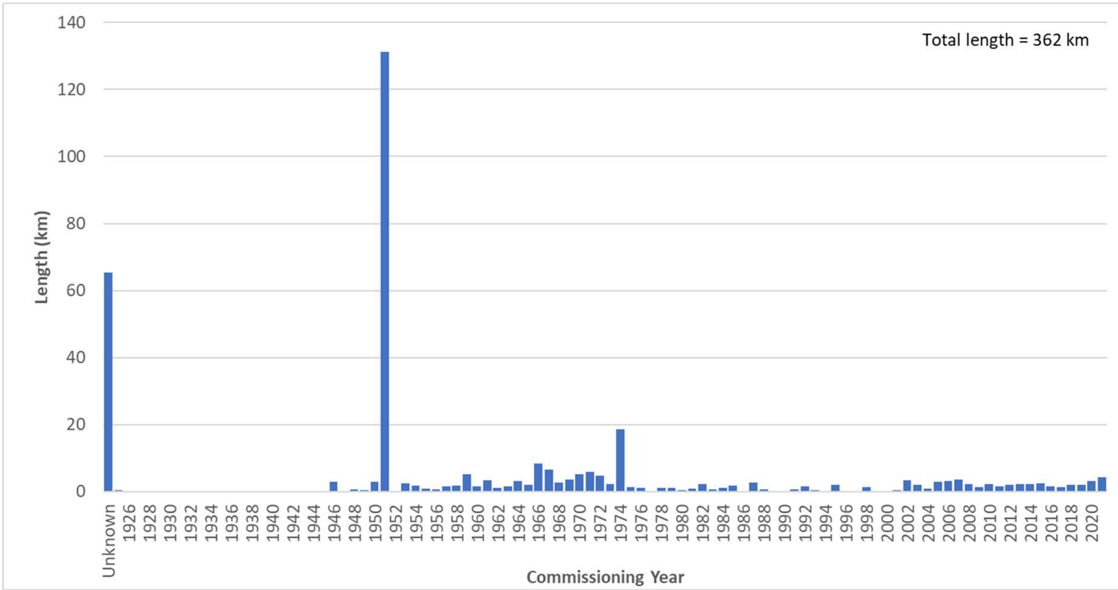
Merton	37.9	5.6	1,469	33.8/km
Middlemarch	8.9	0.1	344	38.2/km
Milburn	2.7	0.2	110	38.2/km
North Balclutha	24.4	6.5	1,263	40.9/km
Oturehua	1.8	0.1	93	48.6/km
Owaka	21.0	2.3	946	40.5/km
Paerau	0.4	0	40	89.6/km
Palmerston	33.0	1.5	1,045	30.3/km
Patearoa	4.2	1.1	164	31.2/km
Port Molyneux	8.3	0.6	406	45.2/km
Pukeawa	0.9	0.0	76	82.5/km
Ranfurly	26.9	3.0	1,219	40.9/km
Remarkables	0	48.4	3,015	62.2/km
Waihola	12.4	5.3	710	40.0/km
Waipiata	5.4	0.3	204	35.5/km
Waitati	26.9	7.2	1,101	32.3/km
Wedderburn	1.1	0	51	47.3/km
Wanaka	0	12.8	573	44.9/km
Total/average	**360**	**107**	**19,730**	**42.2/km**

Overhead LV Conductors

The OJV’s age profiles for overhead LV conductors and for poles are shown respectively in Figure 37 and Figure 38.

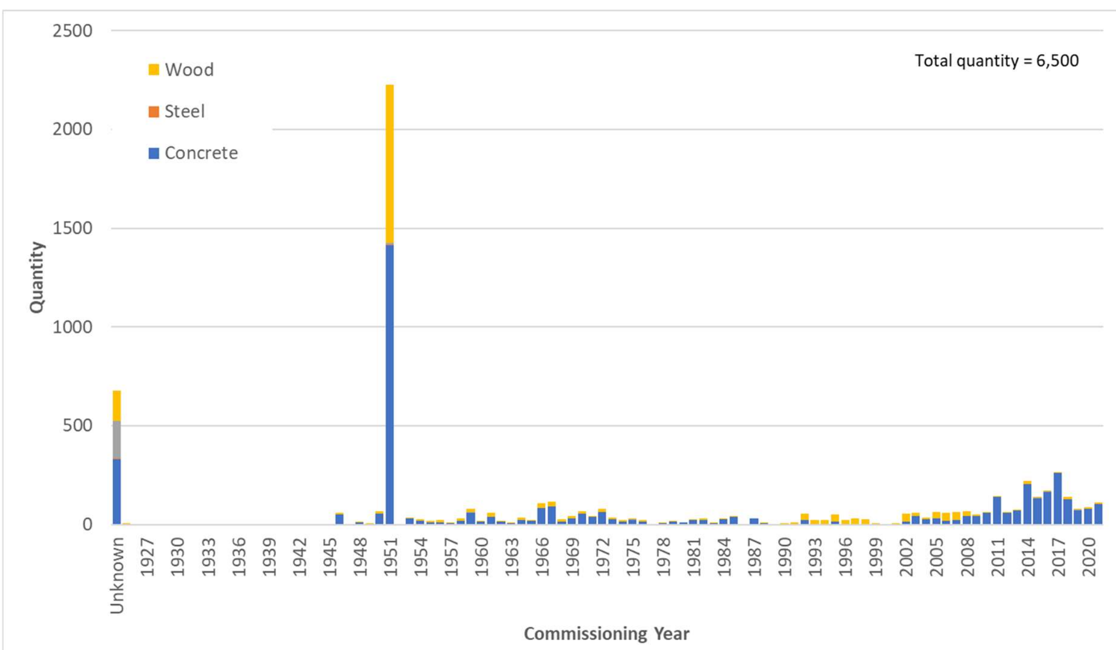
Overhead LV conductors are replaced based on their condition. New overhead lines are ABC (Aerial Bundled Conductors) which does not require cross arms and insulators and has PVC insulation improving line safety.

Figure 37: Overhead LV Conductors



LV Poles are renewed as required based on their condition as identified during the regular inspections of the network. The number of poles and their commissioning year is presented below.

Figure 38: LV Poles

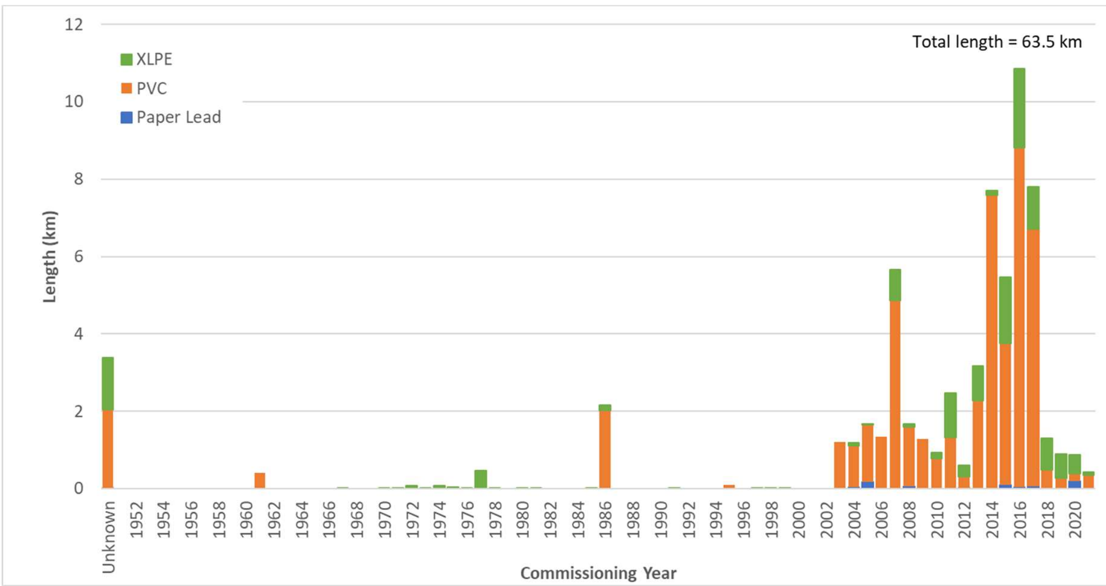


Underground LV Cables

The LV cable commissioning year profile is shown in Figure 39 and shows several assets beyond nominal life. In practice cables are left in service until performance deteriorates and impacts on service levels.

Several 400 V cables installed in the early 1970s are now reaching capacity due to in-build and greater demand per household. This is typically seen as an increase in voltage complaints received due to excessive volt drop during periods of peak loading.

Figure 39: LV Cables



Customer Connections

OJV provides a connection to the network via sixteen retailers which convey electricity over the network. Customer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large customers. In most cases the fuse forms the demarcation point between OJV's network and the customer's assets (the "service main") and this is usually located at or near the physical boundary of the customer's property. All "other assets" convey energy to customers and are a cost that must be matched by the revenue derived from the customer connections. The number and classes of customer connections are listed in Table 23.

Table 23: Classes of Customer Connections

	Small (<=20 kVA)				Medium (21-99 kVA)			Large (>=100 kVA)				
	<=15 kVA 1ph & 3ph	Low User	Streetlights & Unmetered	20 kVA 1ph	21-30 kVA 3ph	41-50 kVA 3ph	51-75 kVA 3ph	100-110 kVA 3ph	135-175 kVA 3ph	200-300 kVA+ 3ph	Individual Half Hour Metered	Total
Apr-21	11,888	5,229	97	76	230	386	115	56	15	20	119	**18,231**
May-21	11,966	5,219	98	77	228	388	115	56	15	20	119	**18,301**
Jun-21	12,031	5,208	99	77	227	391	113	55	14	20	120	**18,355**
Jul-21	12,037	5,234	99	76	229	390	113	56	14	20	121	**18,389**
Aug-21	12,116	5,230	99	76	230	389	112	57	14	20	122	**18,465**
Sep-21	12,203	5,213	99	76	231	394	114	57	14	21	122	**18,544**
Oct-21	12,265	5,208	99	76	230	395	114	57	14	21	122	**18,601**
Nov-21	12,352	5,193	99	76	231	396	115	58	14	21	123	**18,678**
Dec-21	12,421	5,195	98	76	232	396	115	59	14	22	123	**18,751**
Jan-22	12,463	5,183	98	75	232	395	115	59	14	22	123	**18,779**
Feb-22	12,494	5,190	97	75	232	395	114	60	13	21	123	**18,814**
Mar-22	12,565	5,180	97	75	232	399	115	59	13	21	125	**18,881**

Assets for Control and Auxiliary Functions

OJV has a range of other assets to provide control or other auxiliary functions as described in the following tables and paragraphs.

Load Control Assets

Load Control Assets	
Ripple Injection Plant and Receivers	Electricity retailer-owned ripple relays at the customer's premises respond to injected ripple signals and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network. OJV currently owns and operates ripple injection plants at Balclutha, Palmerston and Ranfurly. The ripple function in the Frankton area is provided by Aurora Energy under a service arrangement.

Protection and Control

Protection and Control	
Circuit Breakers	Circuit breakers provide switching and isolation points on the network and generally work with protection relays, to provide automatic detection, operation and isolation of faults. They are usually charged spring or DC coil operated and able to break full load current as well as interruption of all faults. Singe-phase circuit breakers are used for the protection of SWER lines.
Protection Relays	Protection relays have always included over-current and earth-fault functions but can also include voltage, frequency, distance, directional and circuit breaker fail functionality in addition to the basic functions.

Protection and Control	
	Other relays or sensors may drive circuit breaker operation. Examples include transformer and tap changer temperature sensors, gas accumulation and surge relays, explosion vents or oil level sensors.
Fuses	Fuses provide fault current interruption of some faults and may be utilised (by manual operation) to provide isolation at low loading levels. As fuses are simple over-current devices, they do not provide a reliable earth fault operation, or any other protection function.
Switches	Switches provide no protection function but allow simple manual operation to provide control or isolation. Some switches can interrupt considerable load (e.g., ring-main unit load break switches) but others such as air break switches may only be suitable for operation under low levels of load. Links generally require operation when de-energised, and so provide more economic but less convenient switch points.
Batteries and Chargers	Batteries, battery chargers, and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions and allow continued operation of plant throughout any power outage.
Voltage Regulating Relays	Voltage Regulating Relays (VRRs) provide automatic control of the 'Tap Change on Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.
Neutral Earthing Resistors (NERs)	Neutral Earthing Resistors (NERs) installed at zone substations limit earth fault currents on the 11kV & 22kV distribution network. These significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs.

SCADA and Communications

OJV's current communications infrastructure was installed in 2000. It comprises a UHF link and multipoint base station network for SCADA, and a VHF repeater network for voice communications between mobile field staff, depots and System Control.

Since 2000 the electricity industry has experienced dramatic change. The development of advanced digital relays, distributed energy resources and smart metering will place an ever-increasing demand on communications networks.

Whilst OJV 's existing analogue communications networks have been both reliable and cost effective, the challenge for OJV now is to balance the benefit that modern digital infrastructure brings in the context of the operational environment, with the level of investment required to modernise and futureproof the overall communications infrastructure.

SCADA and Communications	
SCADA Master Station	Supervisory Control and Data Acquisition (SCADA) is used for control and monitoring of zone substations and remote switching devices, and for activating load control plant The OJV SCADA master station is located at PowerNet's Balclutha Office with an operator node at the System Control Centre at Racecourse Rd, Invercargill. This system is supplied by a New Zealand manufacturer, Abbey Systems. The Frankton network's SCADA master station is located at PowerNet's System Control Centre at Racecourse Road, Invercargill.
Communication Media	OJV currently owns and operates a UHF radio network between the Otago network zone substations and the SCADA master station at Balclutha. A WAN network connects to System Control, from where control commands may be issued. This equipment is checked and maintained annually by the agents. The UHF radio network also links thirty distribution line reclosers and switches to the SCADA master. A VHF Radio telephone repeater network is also used for communications between mobile field staff, depots, and System Control.

SCADA and Communications	
	The Frankton network owns and operates fibre-optic cables between the Remarkables zone substation and the Frankton GXP, which are used for protection signalling. Its other communications services are leased.
Remote Terminal Units	RTUs at zone substations and distribution switchgear sites provides the interface between network equipment and the communications link with System Control.

Mobile Plant/ Load Correction/ Generation

Other Assets	
Generation	OJV do not own any mobile generation plant but may utilise any of three diesel generators owned by PowerNet on a rental basis. These are rated at 440kW, 350kW and 220kW. There are no stand-by generators owned or able to be utilised by OJV.
Power Factor Correction	Customers are required to draw load from connection points with sufficiently good power factor so as to avoid the need for network scale power factor correction. As such OJV does not own any power factor correction assets.
Mobile Substations	OJV can utilise a temporary 11 kV regulator when required during planned outages. The regulator supports the distribution line voltage during load transfers, reducing the incidence of consumer shutdowns. At zone substations, OJV can utilise a TPCL owned trailer-mounted 5 MVA 33/11 kV mobile substation with cable connections. The mobile substation allows zone substations' transformers and switchgear to be bypassed for maintenance or construction of new substation infrastructure.
Metering	Time-of-use (TOU) meters have not been installed at any of the Otago network zone substations; instead OJV relies on the metering information derived from SCADA measurements, the retailer's TOU meters for the largest 50 customers, and the Grid Exit Point metering.

3.2 Load Characteristics

Load profiles for domestic households are described in the following paragraphs.

Domestic Load Profiles

Standard household demand peaks in the morning (10:30am) and evening (6:30pm). The use of heat pumps is increasing electricity usage, with no noticeable impact over the summer hot period yet. Peaks normally occur in the winter months as heating requirements increase. A typical daily domestic load profile and a typical annual domestic load profile are shown in Figure 40 and Figure 41 respectively.

Figure 40: Domestic Feeder Daily Load Profile

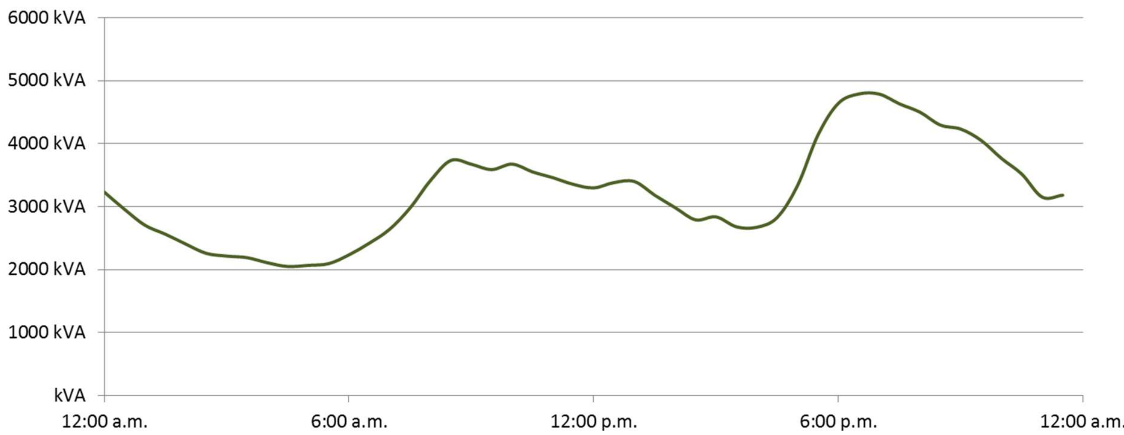
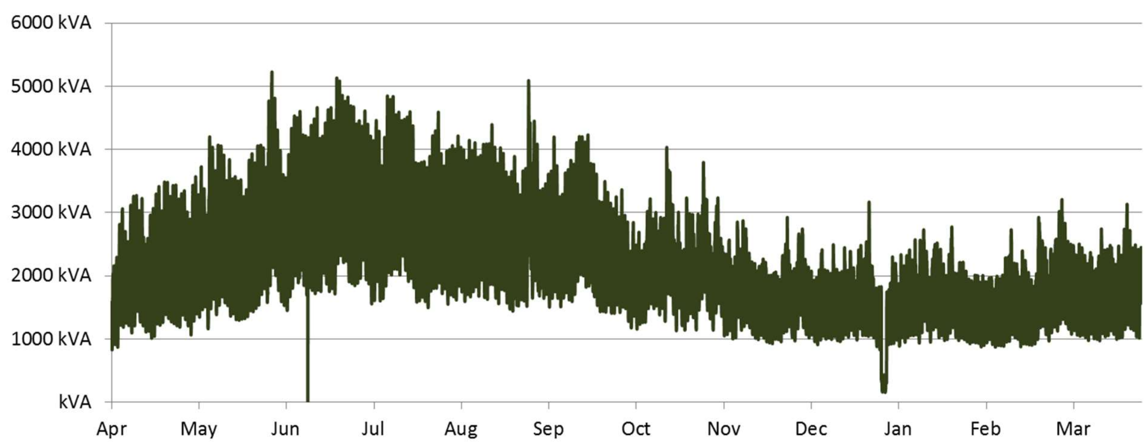


Figure 41: Domestic Feeder Yearly Load Profile



Farming Load Profiles

In South Otago the predominant farming load is dairy farming with the milking season between August and May with morning and late afternoon peaks. The remaining farms normally have very low usage by pumps and electric fences, with peak usage during the few days of shearing or crop harvesting. In

Central Otago and the Maniototo the predominant load is irrigation with the peak loads over the summer hot dry periods. Typical profiles are shown in Figure 35 and Figure 36.

A notable feature of farm irrigation load is its effect on measures of transformer utilisation as irrigation connections employ distribution transformer capacity but contribute almost no demand at the time of the network winter peak.

Figure 42: Typical Rural (Farming) Feeder Daily Load Profile

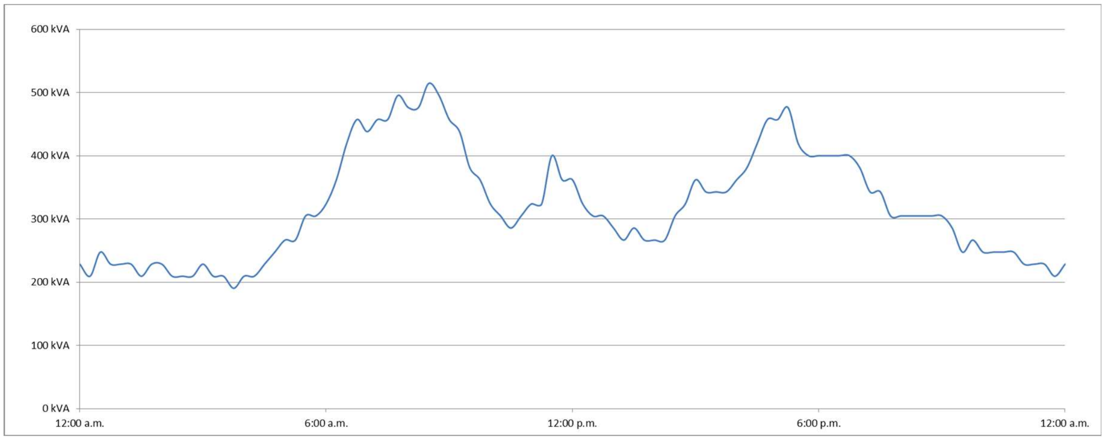
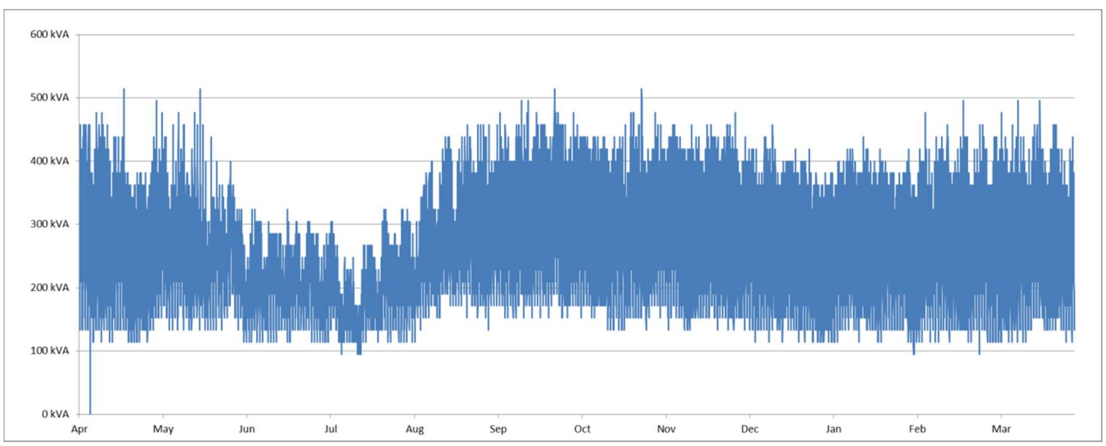


Figure 43: Typical Rural (Farming) Feeder Yearly Load Profile



Energy and Demand Characteristics

Key energy and demand values for the year ending 31 March 2022 are presented in Table 24.

Table 24: Energy and Demand Values

Parameter	Value	Long-term trend
Energy Conveyed	471 GWh	Variation around minimal growth

Parameter	Value	Long-term trend
Maximum Demand[3]	68 MW	Large variation around minimal growth
Load Factor	79%	Reasonably constant
Losses	4.4%	Varying

Maximum demand and total energy conveyed (as recorded for any year) are greatly affected by the weather and determining growth rates from this historical data is challenging. Mathematical treatment such as "best fit" curve application yields completely different results when applied to different past time periods, for instance five (5), ten (10) or twenty (20) years. Shorter time periods give variable results due to the large influence of each calendar year, while longer time periods do not account for recent trends. Growth rates are often based on an educated estimate from the planning engineer and confidence in the growth rates shown in Table 24 is low.

[3] This is coincident maximum demand which is different from the sum of the individual demands at each GXP, which will be greater than the coincident demand due to diversity.

4 Risk Management

OJV is exposed to a wide range of risks and utilises risk management techniques to keep risk within acceptable levels. This section describes the changes in the risk profile between 2023 and 2024.

4.2 2024-34 Update Risk Management Methods

Risk Treatment and Mitigation

PowerNet has developed and operates a Business Continuity Plan that gets activated in the event of a significant risk materialising. This plan is being updated to utilise the national Coordinated Incident Management System (CIMS) (3rd edition). CIMS represents New Zealand's official framework to achieve effective co-ordinated incident management across responding agencies. A number of the Senior Leadership Team members and staff have been trained in CIMS to manage the Business Continuity Team should any such events occur. Training is continuing to ensure sufficient resources will be available in any high risk event. The Business Continuity Plan is tested on a regular basis using real life scenarios to ensure that it functions effectively. CIMS will also be activated at a regional or national level should a High Impact, Low Probability event affecting more than just the network occur.

4.3 2024-34 Update Company Related Risks (General)

Significant company related risks that were identified are described in the next paragraphs.

War in the Ukraine

Although the war in the Ukraine is not directly affecting OJV, it has led to cost increases, especially in the price of fuel. These increases flow through to the cost of work. Given the revenue cap under which we operate which influences the amount of money we can spend, any cost increase negatively affects the volume of work that can be done.

Conflict in Gaza

At the time of writing the effects of the conflict in Gaza is still unknown, but it has the potential to affect the supply of crude oil, should the conflict escalate.

4.4 2024-34 Update Asset Management Risks

Reliability and Resilience

Reliability and resilience are two important but distinct concepts when it comes to electricity distribution networks. They both pertain to the ability of the network to provide continuous and dependable electric service, but they address different aspects of the network's performance and response to various challenges. Here's an explanation of the key differences between reliability and resilience.

Reliability

Reliability refers to the consistency and predictability of electricity supply within the distribution network. It focuses on the network's ability to deliver power to customers without frequent or extended interruptions. Key characteristics of reliability include:

- Minimal Outages: A reliable network experiences minimal power outages, and when outages do occur, they are typically short in duration.
- Consistent Voltage and Frequency: Electricity is delivered with stable voltage and frequency, ensuring that it meets the quality and quantity requirements for various electrical devices.
- High Uptime: A reliable Network has a high uptime, which means it operates without significant disruptions for extended periods, providing continuous service to customers.
- Low Frequency of Failures: Infrequent equipment failures, such as transformer or circuit breaker malfunctions, indicate a reliable network.

Resilience

Resilience, on the other hand, focuses on the network's ability to withstand and recover from various disruptions, including unexpected events and extreme conditions. Resilience addresses how quickly the network can bounce back from disruptions and continue to provide electricity. Key characteristics of resilience include:

- Rapid Recovery: A resilient network can quickly recover from outages, damage, or disturbances and restore power to affected areas in a timely manner.
- Adaptability: Resilience includes the ability to adapt to changing circumstances, whether it's severe weather, equipment failures, or other unforeseen challenges.
- Redundancy: Resilient networks often incorporate redundancy in their design, allowing for alternative pathways and resources to deliver electricity in case of disruptions.
- Robustness: Resilience involves robust infrastructure and operational practices that can withstand extreme conditions, such as hurricanes, wildfires, or cyberattacks.

In summary, reliability primarily focuses on the prevention of power outages and the consistent delivery of electricity, emphasizing the quality and stability of service. Resilience, on the other hand, focuses on the network's ability to recover and adapt to disruptions, ensuring that power can be restored quickly after incidents or adverse events. Both reliability and resilience are critical for maintaining a dependable and secure electricity distribution network, and they often go hand in hand to provide a high level of service to customers, especially in the face of changing climate conditions and other external challenges.

A further resilience complication is introduced by decarbonization. The impact of power outages will increase significantly when the society switches from using gas and petrol for transportation and heating to using electricity as the primary source of energy for homes. In contrast, by using their batteries to power essential home appliances, EVs can improve the resilience of their households.

The adoption of any new technology on the distribution network must first be thoroughly examined via the resilience lens. One must allow the failure of communication systems, such as the hot water control system used for emergency load shedding, which is essential to maintaining network security and its recovery after an incident. The operation of these systems would be placed at risk if they transitioned to new technology that was reliant on cell phone networks, due to the inevitable overloading of cell phone networks that occurs following a major event, and the short battery backup times at cell towers. This vulnerability has been demonstrated by the Christchurch and Kaikoura earthquakes, and again during Cyclone Gabrielle. It is essential that telecommunications network operators, as providers of critical infrastructure, adjust their contingency plans to accommodate the long outages on the electrical supply network that can occur during major events, rather than continuing to optimise their systems for business as usual operation.

Climate Change

Climate change is reshaping our planet in profound ways, and one of its less discussed but critical consequences is the impact on electricity distribution networks. As global temperatures rise and extreme weather events become more frequent and severe, the reliability and resilience of our electrical networks are being put to the test. This article explores the effects of climate change on electricity distribution networks, the challenges it poses, and the strategies being adopted to mitigate these impacts.

Extreme Weather Events

One of the most immediate and tangible effects of climate change on electricity distribution networks is the increase in extreme weather events. Hurricanes, tornadoes, floods, and wildfires have become more common and destructive. These events can damage power lines, substations, and other critical infrastructure, leading to widespread power outages. The cost of repairing and upgrading the network to withstand such extreme weather is a significant burden on utility companies and, ultimately, customers.

Temperature Extremes

Climate change also brings temperature extremes. Hotter summers and more severe winter storms can strain electricity distribution networks. In hot weather, the demand for electricity spikes due to increased use of air conditioning, potentially overloading the system. During cold spells, heating demands similarly increase. To meet these demands, network operators must continually adjust generation and distribution, which can stress the infrastructure and raise operational costs.

Sea Level Rise

Sea level rise, driven by climate change, poses a unique threat to coastal electricity distribution networks. Many power stations, substations, and transmission lines are situated near the coastlines. As sea levels rise, these facilities are at greater risk of inundation and saltwater damage. Even minor flooding can disrupt electricity supply and result in costly repairs or upgrades to protect these assets from saltwater intrusion.

Renewable Energy Integration

While renewable energy sources like solar and wind power are essential for mitigating climate change, they also introduce new challenges for electricity distribution networks. These sources are intermittent and variable, making network management more complex. Climate change can exacerbate this intermittency, affecting the consistency of renewable energy generation. This requires better network infrastructure and energy storage systems to manage the fluctuations effectively.

Mitigation and Adaptation Strategies

To address the challenges posed by climate change, OJV employs various strategies:

a) Infrastructure Resilience: Reinforcing and upgrading existing infrastructure to withstand extreme weather events.

b) Improved Monitoring and Analytics: Investing in advanced monitoring and data analytics to predict and respond to weather-related disruptions and optimize network operations. To this effect the deployment of an OMS/ADMS system is under investigation.

c) Renewable Energy Integration: Expanding and modernizing the electricity distribution networks to accommodate the growing role of renewable energy sources, including smart networks and energy storage systems.

d) Disaster Preparedness: Developing robust disaster recovery and preparedness plans to respond quickly to extreme weather events, minimizing service interruptions and recovery costs. To this end, CIMS is being deployed.

e) Public Awareness: Raising awareness among customers about the importance of energy conservation and network reliability and encouraging energy-efficient practices.

Otago has a very diverse climate. Temperatures are generally lower than the rest of New Zealand, however maximum temperatures higher than 30°C occur in summer, especially inland. Overall typical summer afternoon temperatures are between 18°C and 26°C, and in winter overnight temperatures are between -2°C and 3°C, with frosts which vary across the province depending on topography. The mean temperatures are 9°C to 11°C, and temperatures are lower in elevated and mountainous areas.

Westerly winds prevail, with speed and direction affected by local topography. Generally coastal areas subject to strong winds while inland the winds are lighter. Sea breezes and South Westerly winds are also common on the east coast

The South Otago coast is quite cloudy, and sunshine hours are higher inland except around Queenstown and Cromwell, because mountain ranges result in an increased number of cloudy days.

Rainfall varies widely, with the western ranges receiving ten times the rainfall of Central Otago which is the driest region in New Zealand. Otago does not experience significant seasonal variation in the frequency of wet days. Towards the coast between 100 and 180 wet days per year are typical. In Central Otago there are only 65 wet days on average.

To get the region ready for the effects of climate change, utilities and local authorities must coordinate their reaction. To effectively defend the network against these threats, PowerNet is updating its policies and guidelines. PowerNet rules and standards must be closely matched to a cohesive plan throughout, which will necessitate more collaboration with local authorities to comprehend their defence measures and impact revisions to the District Plan. Climate change is having a profound and multi-faceted impact on electricity distribution networks. Extreme weather events, temperature fluctuations, sea level rise, and the integration of renewable energy sources are all challenging the resilience and reliability of the network. Utility companies and policymakers must work together to implement mitigation and adaptation strategies to ensure a sustainable and secure energy future. As we confront the effects of climate change, our electricity distribution networks must evolve to meet the changing demands of a warming planet.

These risks were unpacked in more detail in the 2023-33 AMP:

> *In this AMP, risk is defined as any potential but uncertain occurrence that may impact on OJV's ability to achieve its objectives and ultimately the value of its business.*

OJV is exposed to a wide range of risks and utilises risk management techniques to keep risk within acceptable levels. This section examines OJV's risk exposures, describes the management of these exposures and activities to reinstate service levels should disaster strike.

4.1 Risk Strategy and Policy

"Understand and Effectively Manage Appreciable Business Risk" is a key corporate strategy and critical business task within OJV. As such, OJV's asset management strategies (directly or indirectly) also incorporate risk management.

PowerNet developed a risk management policy that informs the risk management framework to formalise the practices for the effective management of risks that OJV's business faces. The policy was approved by the PowerNet and OHV Boards. This ensures greater consistency in the quantification of various risks and correct prioritisation of their mitigation, as well as ensuring regularity of review. The framework is consistent with the ISO Standard ISO 31000:2018 Standard: Risk Management - Guidelines.

4.2 Risk Management Methods

PowerNet's risk management methods are used to manage OJV's risk to acceptable levels. Decision making related to OJV's asset management risks is guided by the following principles:

- Risk plans will in general only focus on one major event at a time.
- Safety of the public and staff is paramount.

- Essential services are a secondary priority.
- Large impact work takes priority over smaller impact work.
- Switching to restore power supply takes priority over repair work.

Risk Identification

Risks need to be identified before they can be mitigated. Many risks might seem obvious, yet the identification of other ones require experience and insight into the many factors that could have a significant impact on business objectives. The following risk categories have been established to ensure that various risk types are considered and review responsibility be allocated to the applicable manager.

- Health and Safety.
- Environmental.
- Financial.
- Network Performance.
- Operational Performance.
- Reputation.
- Governance.
- Regulatory Change and Compliance.

This top-down approach is supplemented by a less formal bottom-up process where staff are encouraged to consider and report any risks as they become evident. The Health and Safety category is an exception as a formal policy exists to ensure as many incidents as possible are proactively reported (including near hits) to help identify hazards and control measures as a priority.

Risk categories are reviewed when there is a change in perception of the risks that OJV faces, especially following events which may affect local networks, other catastrophic events which might have global impact, or a change in regulations which may require risk to be considered in greater detail.

Risk Quantification

Once a risk has been identified it is quantified by determining the following:

- The severity of consequences associated with the risk.
- The probability that the consequences will be encountered.

These factors are categorised using relative terms as indicated the following tables to encourage an intuitive assessment of consequence and probability. This categorisation also allows for the use of more robust calculations where practical (especially regarding probability).

Table 25: Consequence Descriptions

Consequence	Description
Insignificant	Operational impact easily handled through normal internal control processes
Minor	Some disruption possible; able to be managed with management input
Moderate	Significant disruption possible; managed with additional management input and resources
Major	Business operations severely damaged or disrupted; requires extraordinary management input and resources
Extreme	Disaster; extreme impact on staff, plant, and/or operations

Table 26: Event Consequence Categorisation

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Health and Safety	First aid treatment	Medical treatment injury or illness	Lost time injury or illness	Serious permanent disabling injury/illness	Fatality/fatalities
Environmental	Reversible impact, addressed immediately, remediated < 24 hours	Reversible impact, addressed short term, remediated < 1 week	Reversible impact, addressed medium term, remediated < 1 month	Long term recovery typically taking years	Irreversible widespread damage to environment
Financial	Asset impact of < 0.1% or revenue impact of < 0.1%	Asset impact > 0.1% and < 0.2% or revenue impact > 0.1% and < 1%	Asset impact > 0.2% and < 1% or revenue impact > 1% and < 10%	Asset impact > 1% and < 20% or revenue impact > 10% and < 50%	Asset impact of > 20% or revenue impact of > 50%
Network Performance	Exceeding SAIDI/SAIFI limits during year, actively managing performance	Exceeding SAIDI/SAIFI limits during year, increased management effort and intervention required	Recoverable and explainable breach of SAIDI or SAIFI regulation (no underlying asset condition issues)	Significant breach of SAIDI/SAIFI regulations triggering investigation and penalties (underlying systemic asset condition issues)	Ongoing repeated significant breaches resulting in loss of control of AMP programme due to regulatory intervention
Operational Performance	Operational impact easily handled through normal internal control processes	Some disruption possible; able to be managed with management input	Significant disruption possible; managed with additional management input and resources	Business operations severely damaged or disrupted; requires extraordinary management input and resources	Disaster; extreme impact on staff, plant, and/or operations

	Consequence				
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Reputation	Social media attention - one-off public attention	Attention from recognised regional media - short term impact on public memory	Ongoing attention from recognised regional media and/or regulator inquiry	Attention from recognised national media and/or regulator investigation - medium-term impact on public memory	International media headlines and/or government investigation - long-term impact on public memory
Governance	Board awareness	Board and shareholder awareness	Perception of systematic underperformance, shareholder concern	Ongoing shareholder dissatisfaction	Dysfunctional governance - major conflicting interests or fundamental change in governing board of directors
Regulatory Change and Compliance	Audit provisional improvement notice	Minor non conformance	Breach with risk of prosecution or emerging regulatory change with potential to affect business	Prosecution of Director and/or officers or regulatory change enacted	Breach resulting in imprisonment of Director and/or officers or appointment of statutory board to a network or impact of regulatory change resulting in complete business transformation

Table 27: Event Probability Categorisation

Likelihood	Description	Frequency
Almost Certain	The consequence is expected to occur in most circumstances	Occurs three times or more per year
Likely	The consequence has a reasonably high chance of occurring in many circumstances	Occurs once or twice per year
Possible	The consequence could conceivably occur in some circumstances	Typically occurs in 1-10 years
Unlikely	The consequence is unlikely to occur in most circumstances	Typically occurs in 10-100 years
Rare	The consequence would occur only in exceptional circumstances	Greater than 100-year event

Risk Ranking

Consequence and probability provide an overall measure of a risk. The risk matrix in Table 28 indicates how these factors can be combined to present a relative risk level.

Table 28: Risk Ranking Matrix

		Consequence				
	Risk Rating	Insignificant	Minor	Moderate	Major	Extreme
Likelihood	Almost Certain	3	4	6	7	8
	Likely	3	3	5	6	7
	Possible	2	3	4	5	7
	Unlikely	1	2	3	4	6
	Rare	1	1	2	3	5

The risk matrix inherently recognises HILP (high impact low probability) events and gives them a high-risk level ranking so that they receive appropriate attention as described below.

Table 29: Management attention to risk rankings

Low	Medium	High	Critical
Risk managed through routine management/internal control procedures	Risk to be reported to relevant manager, may require additional risk treatment actions	Risk to be reported to chief executive and senior leadership team to approve and monitor risk treatment actions	Risk to be reported to the board to approve and monitor risk treatment actions
Levels 1 & 2	Level 3	Level 4 & 5	Level 6, 7 & 8

Risk Treatment and Mitigation

Risks can often not be eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. Often several treatment options are available and each is likely to have different cost, effort and timeframes associated. Furthermore, each treatment option could be more or even less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 30 summarises the types of treatment options that should be considered for any risk. These options are ordered by effectiveness for the control of risk.

Table 30: Options for Treatment of Risk

Option	Description
Terminate	Deciding not to proceed with the activity that introduced the unacceptable risk, choosing an alternative more acceptable activity that meets business objectives, or choosing an alternative less risky approach or process.
Treat	Implementing a strategy that is designed to reduce the likelihood or consequence of the risk to an acceptable level, where elimination is excessive in terms of time or expense.
Transfer	Implementing a strategy that shares or transfers the risk to another party or parties, such as outsourcing the management of physical assets, developing contracts with service providers or insuring against the risk. The third-party accepting the risk should be aware of and agree to accept this obligation.
Tolerate	Making an informed decision that the risk rating is at an acceptable level or that the cost of the treatment outweighs the benefit. This option may also be relevant in situations where a residual risk remains after other treatment options have been put in place. No further action is taken to treat the risk; however, ongoing monitoring is recommended.

Good risk management recognises that limited resources are available and that all risks cannot immediately be effectively mitigated. The desired outcome for risk treatment is a low-cost option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe. A low-cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation might be an obvious choice but deciding between high cost-effective treatments and low cost but less effective risk treatment options may be difficult and requires careful evaluation of all factors involved.

Depending on the magnitude of risk identified a large-scale programme may be initiated to quickly reduce risk. Often asset management related risks will have mitigating solutions that become a part of design standards used on the network. The level of risk will determine if standards are retrospective i.e., applied to shape the existing network rather than only applying to new assets installed.

Effective risk management requires prioritisation of the many risk reduction actions identified and to do this the "*greatest risk reduction utilising available resources*" is used as a guiding principle. Appropriate resourcing needs to be considered and adjustment of available resources may be required to control risk appropriately. This is explicitly recognised as part of the Health and Safety at Work Act where sufficient resources to reduce hazards "*as far as reasonably practicable*" must be provided.

PowerNet has developed and operates a Business Continuity Plan that gets activated in the event of a significant risk materialising. A number of the Senior Leadership Team has been trained to manage the Business Continuity Team should any such events occur. The Business Continuity Plan is tested on a regular basis using real life scenarios to ensure that it functions effectively. This plan will be activated should a High Impact, Low Probability event occur.

4.3 Company related risks (general)

Significant company related risks that were identified are described in the next paragraphs.

COVID pandemic - Loss of key service providers; business operations disrupted

This risk manifested during 2020 when the COVID-19 virus caused a worldwide pandemic. The probability of this risk occurring was deemed "*Rare*", but it happened. The risk is now a "*Critical*" risk. However, in line with Central Government guidelines, Electricity Distribution is an essential service and work needs to continue. The following treatment responses are available.

- Adhere to government guidelines.
- Work to the PowerNet pandemic plan. This includes measures such as working from home, only critical faults and critical maintenance work and providing emergency kits for offices.
- Supply chain management.
    - Assist in identifying critical suppliers and manufacturers so that the manufacture of critical equipment such as poles can continue.
    - Ensure sufficient stock levels of critical items and consumables, including safety equipment such as masks and disposable gloves.
    - Identify key contractors and negotiate availability agreements.
- Contact tracing.

The mitigation measures mostly worked, apart from completing some major projects and some maintenance work. Major projects were delayed by the difficulties in getting imported equipment into New Zealand. Non-critical but nevertheless essential maintenance were postponed and the resultant backlog has not been fully cleared. This has led to underspending in some CAPEX and OPEX categories.

Cyber Security

Cyber security events were detected and intentional damage was prevented by the IT security systems. There is however a notable increase in these types of events.

Industry Regulation

Gaps in or breaches of industry regulation have been identified as the following:

- Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
- Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
- Management contract – failure of PowerNet as OJV's asset manager.
- Regulatory – failure to meet regulatory requirements.
- Resource – field staff to undertake operation, maintenance, renewal, up-sizing, expansion and retirement of network assets.

Table 31: Industry Regulation Risks and Responses

Event	Likelihood	Consequence	Responses
Uncompetitive Return on Investment	Likely	Major	• Cut cost to a level where reliability of supply will not materially deteriorate but will also not improve.
Failure of the Management Contract	Rare	High	• Continue management contract with PowerNet noting that it operates a Business Continuity Plan • PowerNet investment in improving its business management systems and processing
Regulatory breaches	Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Inadequate Resource to execute required work	Unlikely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

4.4 Asset Management Risks

The following extract from the corporate risk register indicates risks specifically relating to Asset Management.

Table 32: Asset Management Risks

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure; ineffective maintenance; ineffective fleet plans; budget constraints; lack of future network planning	Reliability Collapse/fall causing harm Voltage causes harm	Treat	Implement AMMAT improvements; resourcing; fleet plans; business management framework
Network Performance	**Operational systems failure due to breakdown in telecommunications**	SCADA communications has one centralised communications point that all information is passed through.	Loss of SCADA would require resorting to manual oversight of the networks	Treat	3 yr. Project underway to provide further links - due for completion 2023. Use of external service providers until own network is fully developed
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism Reputation	Damage to equipment Damage to systems/data Change in network configuration SAIDI/SAIFI Impacts	Treat	Programme to replace locks and improve security underway

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
			Reputation Impacts		
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision)	Objection of landowner where line is over boundary Demand for removal of assets and/or legal action	Tolerate	
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Limited staff, facilities or equipment available	Treat	Completion of seismic strengthening Design of networks to avoid high event probability areas
Operational Performance	**Full sector reputation damage**	Loss of stakeholder confidence due to nationwide issues and concerns with electricity industry or EDB sector specifically	Significant dissatisfaction with electricity industry due to adverse impacts for customers, such as price shock through changes in sector pricing. Could be triggered by electricity shortage, change in pricing methods impacting on specific customer groups	Treat	Participate in industry forums such as ENA, EEA etc. Ensure that we give feedback to government on issues when we have the opportunity.
Operational Performance	**Potential liability for private lines and connections**	Regulatory change Poor historical process/records Fatality with some repercussion for PowerNet - legal advice has not been tested in court	Obligation to maintain assets vested in the network	Treat	Association to ENA and MBIE: *(currently reviewing situation with aim of a consistent industry solution)*
Operational Performance	**Major Contractual Breach**	Breach of contractual obligations in place with key counterparties, resulting in legal action with potential serious financial implications and/or	Breach of agreement results in loss of ability to continue to provide the service. This results in a significant reduction in value the business	Treat	Effectively manage all contracts we enter into.

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
		reputational damage			
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Inability to supply	Treat	Review critical spares process Stocktake critical spares Record spares in Maximo Education of staff on spares process and locations Comparison of existing assets to critical spares (and update with changes to the network)
Operational Performance	**Loss of key critical service provider**	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Inability to build or maintain assets Unable to service existing contracts	Treat	Improved identification of critical suppliers Identify alternative suppliers Diversify the workforce Internalise and grow internal workforce Diversify into new markets (create a larger pool)
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Delayed or limited provision of power to consumers Loss of ability to provide power to customers for extended periods	Treat	Develop improved contingency plans for network events
Financial	**Change to EDB Environment**	External decision makers trigger industry disruption and change. Likely to be regulatory intervention in industry structure and/or economic return framework	Forced amalgamation of EDBs with asset value and sales transaction set/influenced by third parties with risk of significant shareholder value destruction	Treat	Ensure that we develop the systems and processes that will make us a leading EDB and put is in a position to be the lead party in any restructure.

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Regulatory Change & Compliance	**Gaps or breaches in Industry regulation**	Changes to the industry environment result in uncertainty of accountability and authority to operate	Ability to operate in part of the industry restricted or removed due to regulatory gap, for example, own / operate new technology and gain value from that opportunity	Tolerate	
Health & Safety	**Public encountering live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Serious injury or fatality Prosecution under H&S Act	Treat	Asset Lifecycle risk management Increase public awareness through various media Asset design and operation
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Breaches of environmental legislation Cost of rehabilitation	Treat	Design standards take environmental risk into account Asset do not contain hazardous substances or hazardous substances are controlled

Asset management risks are in the categories of Network and Operational Performance, Health & Safety and Environmental. These risks can partly or in full be addressed through the asset management system. A summary of the risk assessment under each of these categories is described in the next paragraphs.

Network and Operational Performance

The following network and operational performance risks were identified and the quantification and treatment responses are summarised in Table 33.

- **Equipment Failures** – equipment failures can interrupt supply or prevent systems from operating correctly, e.g., failure of a padlock could allow public access to restricted areas.
- **Fire** – transformers are insulated with flammable mineral oil and buildings contain combustible materials. Fire could be triggered by internal external sources and will impact electricity supply.

Table 33: Risks Associated with Equipment Failures

Event	Likelihood	Consequence	Responses
33 kV & 66 kV Lines and Cables	Possible	Low to medium	• Regular inspections and maintain contacts with experienced faults contractors.

Event	Likelihood	Consequence	Responses
			• Provide alternative supply by ringed subtransmission or through the distribution network where possible, else repair. • All new lines designed to AS/NZS 7000:2010
Power Transformer	Unlikely	Low to medium	• At dual power transformer sites, one unit can be removed from service due to fault or maintenance without interrupting supply. • Continue to undertake annual DGA to allow early detection of failures. • Relocate spare power transformer to site while damaged unit is repaired or replaced. • Deploy the mobile substation where appropriate
11 kV Switchboard	Unlikely	Medium	• Annual testing including PD [4]and IR[5]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard.
11 kV & 400 V Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network where available.
Batteries	Unlikely	Medium	• Continue monthly check and six-monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Unlikely	Medium	• Continue regular operational checks. • Engineer redundancy/backup into protection schemes. • Regular protection reviews. • Mal-operations investigated.
Circuit Breakers	Unlikely	Low	• Backup provided by upstream circuit breaker. • Continue regular maintenance and testing.
SCADA RTU	Unlikely	Low	• Monitor response of each RTU at the master station and alarm if no response after fifteen minutes. • If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Master-station	Very Unlikely	Low	• Continue to operate as a Dual Redundant configuration, with four operator stations. This requires both Servers to fail before service is lost. • Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Unlikely	Medium	• Manually operate plant with test set if SCADA controller fails.
Fire	Very Unlikely	High	• Supply customers from neighbouring substations. • Maintain fire alarms in buildings.

The impact of equipment failure is unpredictable, therefore PowerNet provides a central control room which is staffed 24 hours a day. Engineering staff are always on standby to provide backup assistance for network issues. PowerNet staff and other Contractors provide onsite support for the repair of minor failures. For the repair of medium to large failures or when storms occur, 'on-call' PowerNet staff and contractors are available. Inspection results and equipment failures are reported to the Board in the monthly management report.

[4] PD = Partial Discharge, indication of discharges occurring within insulation.

[5] IR = Infrared, detection of heat of equipment that highlights hot spots.

The following additional network and operational performance risks were identified and their treatment responses are described in the next table.

- **Animals** – could physically connect with overhead conductors (e.g., birds, possums) or cause conductor clashing (e.g., cattle against stays).
- **Third party accidental damage to network** – e.g., car versus pole, over-height loads breaking conductors. The presence of a pole may also increase the damage done to a car and its occupants if the driver veers off the road.

Table 34: Other Network and Operational Performance Risks

Event	Likelihood	Consequence	Responses
Animal	Highly Likely	Low	• Possum guards all poles • Cattle guards, bird spikes as required
Third party accidental	Possible	High (Safety) Low (Network)	• Design (assets, protection settings) to minimise electrical safety consequences of failure • Underground particularly vulnerable areas • Approval process for railway crossings, etc. • Regular inspections for sag etc. • Resource available to bypass and repair.

Health and Safety

Health and safety risks that were identified are listed below with treatment responses indicated in Table 35.

- **Accidental public contact with live equipment** – whether through using tall equipment near overhead lines or through excavating near cables.
- **Step & touch** – faults/lightning strikes causing a voltage gradient, across surfaces accessible to the public, which can cause electric shock.
- **Arc flash** – potential for significant injury to staff from a fault on or near equipment they are using/working on.
- **Underground assets** – safety risks amplified by close proximities and confined space.
- **Staff error** - causing worksite safety risk.
- **Historical assets** - not meeting modern safety requirements.
- **Site security** – unauthorised persons approaching live components through unlocked gate.

Table 35: Health and Safety Risks

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	High	• Public awareness program – social media, radio, print, signage at high-risk areas • Offer cable location service • Emergency services training

Event	Likelihood	Consequence	Responses
			• Relocate/underground near high-risk areas e.g., waterways where feasible • Include building proximity to lines in local body consent process • Audit new installations for correct mitigation, e.g., marker tape/installation depth/Magslab for cable • Regular inspections of equipment to detect degraded protection of live parts
Step & Touch	Unlikely	High	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Underground	Unlikely	High	• De-energise substation before manual switching within substation
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met
Staff Error	Possible	High	• Standardised procedures • Training • Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Medium to High	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Alarms on underground sub hatches • Standardised exit procedures in 3rd party building • Above ground sub clearances to AS2067 s5 • Design to avoid climbing aids etc.

Environmental

The following environmental risks have been identified and their quantification and treatment responses are presented in the next tables.

High Impact Low Probability (HILP) Events

- **Earthquake** – no recent history of major damage. The earthquakes in Christchurch demonstrated that large and unexpected events may occur and these would have a significant impact on the network.
- **Tsunami** – may be triggered by large off shore earthquake.
- **Liquefaction** – post Christchurch's 22 February 2011 **6.3** magnitude earthquake, the hazard of liquefaction as a risk needs to be considered.

Table 36: High Impact Low Probability Risks

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Very Unlikely	High	• Disaster recovery event. • Projects underway to investigate and improve survivability through large seismic events.
Earthquake (6 to 7)	Very Unlikely	Low to High	• Specify so buildings and equipment will survive. • Review existing buildings and equipment and reinforce if necessary.
Tsunami	Very Unlikely	Low to Medium	• Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Unlikely	Low to Medium	• Specify buildings and equipment foundations to minimise impact.

Other Potential Environmental Risks

- Oil spills from transformers or oil circuit breakers
- Release of SF_6 into the atmosphere

Table 37: Other Environmental Risks

Event	Likelihood	Consequence	Responses
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met

Weather Related Risks

The following are potential weather-related risks and their quantification and treatment responses are summarised in Table 38.

- **Wind** – strong winds that either cause pole failures or blow debris into lines.
- **Snow** – impact can be by causing failure of lines or limiting access around the network.
- **Flood** – impact can be washing out of pole foundations or limiting access around the network. The Otago Regional Council manages extensive flood protection works on the Clutha Delta.

Table 38: Weather Related Risks

Event	Likelihood	Consequence	Responses
Wind	Possible	Low	• Design standard specifies wind loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.
Snow	Unlikely	Low	• Design standard specifies snow loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements. • If access is limited then external plant is hired to clear access or substitute.
Flood	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Transformers and switchgear in high-risk areas to be mounted above the flood level. • Zone substations to be sited in areas of very low flood risk.

4.5 System Risks

Existing risks to the electricity system are described in the following sections.

Oil Filled RMUs

Many oil-filled RMUs have operating restrictions in place to mitigate safety risks due to arc flashes. Short term solutions were developed for some models of RMU, which allow safe operation without the inconvenience and reliability impact of operating restrictions. Where these solutions are not available or not practical, operation of these RMUs has been suspended. This mitigates the risk to field staff operators, however, in-situ risk to the public remains and the network has reduced capacity to segment resulting in wider outage areas. Longer term management of these issues is likely to require early replacement of many RMUs.

Some models of RMUs have exhibited faster than usual corrosion which is likely to adversely affect the service life of the assets. Repairs will be carried out where economic and practical to do so, but it is expected that many of these assets will need to be replaced ahead of their nominal life, causing their replacement to overlap with the older but sturdier models that preceded them.

Other Systemic Issues

A model of 11kV ABS with porcelain insulators manufactured during a specific period have been exhibiting premature insulator failure. The cause appears to be moisture ingress following breakdown of the sealing cement at the top of the insulator. The ABSs of the type affected have been closely inspected and prioritised for replacement based on the condition of the cement.

4.6 Asset Criticality

Good practice asset management decisions should not be solely based upon asset health either from condition or non-condition factors. Good practice decision making should also consider the operating context and how failure can affect outcomes such as safety and environment, customer service levels, and lifecycle costs.

The EEA Asset Criticality Guide defines Criticality as "A measure reflecting the relative seriousness of the Credible Consequences of Failure". The EEA guidelines are not yet fully operationalised within OJV. We do however take the location of assets into account when we make asset management decisions.

The plausible consequence of an asset failure next to a school or public facility is the same as when the same asset would be installed somewhere in a paddock. However the credible consequence of the asset failure in the first location is much higher than the credible consequence of the asset failing in the second location, so more intensive risk mitigation measures will be applied to the first asset.

5 Service Levels

No change.

The service levels as per the 2023-33 AMP remain unchanged:

This section describes how OJV sets its various service levels according to the safety, viability, quality, compliance, and price objectives that are most important to stakeholders. It details how well OJV is meeting these objectives and what trade-offs exist between differing stakeholders. Considerations include the desire for Return on Investment (ROI) versus desire for low price with good reliability, safety as priority versus acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

Safety is OJV's top priority and is a primary consideration in the AMP. However, safety has always been a key consideration in network design and the residual risk that can be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Safety KPIs are not presented in the AMP but are available to interested parties upon request.

OJV sets and maintains a number of service levels on behalf of its stakeholders especially its customers. Two important metrics measuring network reliability are SAIFI and SAIDI:

- SAIFI is a measure around outage frequency which translates to the average number of interruptions an average customer would experience annually. OJV is forecasting a planned SAIFI of 0.86 and an unplanned SAIFI of 1.56.
- SAIDI is a measure around outage duration which translates to the average amount of time an average customer would be without power annually. OJV is forecasting a planned SAIDI of 260.3 minutes and an unplanned SAIDI of 142.7 minutes.

These forecasts are average values around which significant variation can be expected. Weather impacts have a randomising influence on the overhead sections of the network. OJV's network reliability has been influenced by extreme weather events in recent years, and its long-term aim is to gradually reduce the average unplanned SAIDI and SAIFI.

OJV's reliability is what can be expected from a network feeding huge rural areas. However, the projected levels may be difficult to maintain towards the end of the DPP3 period due to the Revenue cap limiting additional investment into reliability improvement initiatives and equipment renewal.

Secondary service levels are also set for customer satisfaction for those customers who have experienced an outage (both planned and unplanned). This measures their satisfaction with the length of time they were without supply, and with the information made available to them about their outages. Independent surveys are undertaken annually to determine how customers perceive the service levels they receive from OJV; generally, responses are very positive.

Other service levels maintained are compliance with safety legislation, amenity value legislation and regulations requiring certain performance standards for the business while avoiding interference with other parties.

In addition, OJV is required to set financial efficiency and energy efficiency service levels. OJV sets targets for both network and non-network operational expenditure in terms of ICPs supplied, km of network length and total distribution transformer capacity. These ratios are disclosed directly by the other distribution businesses and may therefore be used for benchmarking OJV's performance against its industry peers. Targets for next years' network operational expenditure ratios are set at: per ICP $289, per km $1,249, and per MVA $24,234 while targets for non-network operational expenditure ratios are set at: per ICP $201, per km $869, and per MVA $16,873.

For efficiency of energy delivery OJV is aiming to achieve an overall load factor of 79%, capacity utilisation of 30% and loss ratio of 5.0%. These are long term average targets as year-to-year variation can be significant and often largely out of OJV's control.

Benchmarking service levels against other predominantly rural electricity distribution businesses indicates OJV is performing well on behalf of its stakeholders.

5.1 Customer Oriented Service Levels

Customer surveys and the outcomes thereof are described in the following section.

Customer Surveys

Customer engagement surveys are completed annually to measure customer perceptions around a range of service levels. This involves contacting a large sample of customers by phone or online survey with a predetermined set of questions; the full questionnaire used is detailed in Annexure 2. This is carried out independently by engaging Research First who collate the results into a customer satisfaction report for presentation.

Statistics around supply quality complaints are kept to measure how often voltage quality issues are experienced by customers. Issues are dealt with at the time but these statistics give an indication of how voltage quality and the response services are trending over time. In addition, following the completion of customer connection work a survey form is sent to the customer to measure satisfaction with the connections service. Results are monitored and any comments given are reviewed and responded to.

Targeted improvement initiatives could result from dissatisfaction being expressed by customers; however survey results show that for the most part customers are happy with the current level of service with 80% rating their power supply as reliable. The survey also indicates that customers have a favourable view of OJV being safety conscious (78%), efficient in service response (74%) and caring for its customers (70%).

The difficulty with these conclusions is that the service levels most valued by customers depend strongly on fixed assets and hence require capital expenditure solutions (as opposed to process solutions) which raises the following issues:

- Limited substitutability between service levels e.g. customers prefer OJV to keep the power on rather than answer the phone quickly.
- Averaging effect i.e. all customers connected to an asset (or chain of assets) will receive about the same level of service.
- Free-rider effect i.e. customers who choose not to pay for improved service levels would still receive improved service due to their common connection.

Primary Customer Service Levels

Surveyed customers have indicated that they value continuity and then restoration most highly; therefore OJV's primary service levels are continuity and restoration. To measure performance in this area OJV has adopted two internationally accepted indices:

- SAIFI (system average interruption frequency index) is a measure of how many system interruptions occur per year per customer connected to the network.
- SAIDI (system average interruption duration index) is a measure of how many system minutes of supply are interrupted per year per customer connected to the network.

These indices align with the Commerce Commission's use of SAIFI and SAIDI (and determines their calculation methodology) in their regulation of local EDBs (including OJV). OJV's projections for these measures over the next ten-year period ending 31 March 2033 are shown in Table 39 and take into account the updated default price-quality path calculation methodology, which includes separated planned and unplanned reliability standards, setting the unplanned reliability standards at 2 standard deviations above the normalised historical average, defining contraventions on an annual basis (rather than a 'two-out-of-three' year basis) and setting the planned reliability standard at three times the historical average and assessing it on a regulatory period basis.

These projections are an average only, given the volatility in reliability statistics due to extreme weather events. OJV's long-term aim is to reduce the average planned and unplanned SAIDI to the Target benchmark.

The treatment of outages that are needed for planned work but where the customer notification timeframes could not be adhered to or where the planned work had to be cancelled is unclear. We have adopted an approach whereby these outages are classified as unplanned outages – cause unknown. This has caused an increase in this reliability category.

Table 39: Reliability Projections

Measure	Class	2022/23	2023/24	2024/25	2025/26	2026/27	…	2032/33
SAIDI	B (Planned)	260.3	162.0	162.0	162.0	162.0	…	162.0
	C (Unplanned)	142.7	132.9	131.6	130.3	129.0	…	121.5

Measure	Class	2022/23	2023/24	2024/25	2025/26	2026/27	...	2032/33
	Total	**403.0**	**294.9**	**293.6**	**292.3**	**291.0**	...	**283.5**
SAIFI	B (Planned)	0.86	0.80	0.80	0.80	0.80	...	0.80
	C (Unplanned)	1.56	1.92	1.90	1.88	1.86	...	1.76
	Total	**2.42**	**2.72**	**2.70**	**2.68**	**2.66**	...	**2.55**

Table 40: Reliability History

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	B (Planned)	60.69	105.14	93.82	90.33	189.11	128.79
	C (Unplanned)	167.01	128.11	141.74	152.37	133.20	141.82
	Total	**227.7**	**233.2**	**235.6**	**242.7**	**322.3**	**270.6**
SAIFI	B (Planned)	0.36	0.56	0.43	0.48	0.72	0.78
	C (Unplanned)	2.06	2.31	2.16	1.78	1.94	2.38
	Total	**2.42**	**2.87**	**2.59**	**2.26**	**2.66**	**3.16**

(Normalised figures)

The frequency of faults and estimated restoration levels for significant network areas are summarised in Table 41.

Table 41: Expected fault frequency and restoration time

General location	Expected reliability
Balclutha, Milton, Ranfurly	One outage per year of about 60 minutes duration
Towns	Two outages per year of about 90 minutes duration
Villages	Three outages per year of about 120 minutes duration
Anywhere else	Four outages per year of about 240 minutes duration

Surveyed customers in all market segments prefer to pay more or less the same line charges to receive similar supply reliability levels. Table 42 displays the thresholds which the Commerce Commission applies to OJV's reliability performance. The boundary values represent the threshold for normalising extreme events, where if unplanned SAIDI or SAIFI in any day exceeds the respective boundary, the contribution to the overall annual SAIDI or SAIFI is capped at that boundary value. The limit represents the upper limits of acceptable reliability for network performance. The unplanned limits must not be breached in any year (after normalising out extreme events); and the planned limits must not be breached when aggregated over the five year regulatory period.

The new DPP3 reliability incentives effective from 1st April 2020 separate planned from unplanned SAIDI & SAIFI. This together with the limits set and the new "one in one year" breach rule increases OJV's likelihood of a limit breach.

Table 42: Reliability Thresholds - DPP3

	Target	Collar	Cap/Limit	Boundary
Unplanned SAIDI	120.02	0.00	160.35	11.81
Planned SAIDI	140.96	0.00	422.89[6]	-
Unplanned SAIFI	-	-	2.4172	0.1776
Planned SAIFI	-	-	1.9242[7]	-

Under DPP3 the Cap, Target and Collar benchmarks are used as part of a SAIDI revenue incentive scheme for improving reliability on the network where cost effective. The SAIFI incentives have been removed under DPP3.

The unplanned SAIDI incentive rate is $4,339 per SAIDI minute, with the maximum gain set at 1.94% and the maximum loss set at 0.65% as a percentage of allowable revenue.

The planned SAIDI incentive rate is $2,169 per SAIDI minute, with the maximum gain set at 1.14% and the maximum loss set at 2.28% as a percentage of allowable revenue.

The Target is OJV's average historical reliability level, and there is no adjustment to OJV's revenue when performance matches the Target. Performance worse than the Target exposes the distributor to losses in direct proportion to performance, up to the Cap where the maximum penalty is imposed. Conversely, performance better than the reliability target allows the distributor to claim extra revenue in proportion to performance, down to the Collar where the maximum bonus is achieved. Performance beyond either cap or collar attracts no further respective losses or gains, however the cap is also the limit of acceptable reliability.

Major Consumers

Significant single loads and their supply arrangements are:

- Oceana Gold's 24 MVA load at Macraes Flat is supplied at 66 kV. Two heavy 33kV lines from the Naseby GXP and large dual rated 33/66kV step-up transformers at Ranfurly feed a single 44 km, 66 kV line to Macraes Flat.

[6] The 5 year DPP3 period Planned SAIDI limit is 2,114.43.

[7] The 5 year DPP3 period Planned SAIFI limit is 9.6212.

- Manawa Energy's[8] 12.25 MW generation station also requires the 66 kV supply at Ranfurly for energy transmission and embedded connection to the major Oceana Gold consumer. A single 66 kV line connects the Paerau Powerhouse and Ranfurly.
- Pioneer Generation's Falls Dam power station is embedded in the 33kV network. The connection comprises a single 33kV line from Ranfurly via Wedderburn and Oturehua zone substations. The generator requires enhanced 33 kV line regulation arrangements at Oturehua substation.
- Silver Fern Farms Finegand plant's 7 MVA of load has manual 33 kV switching capability between three supplies to provide security to it and to customers on three downstream zone substations.
- Fonterra's Stirling dairy plant has 33 kV switching between two supplies to provide recovery of power supply in the event of a fault on one line.
- The Otago Regional Corrections Facility at Milburn has been provided with two 11 kV supplies and automatic change over switchgear to deliver its required security.
- Southern Generation's Mount Stuart wind farm connects via a short spur line into the Glenore to Lawrence 33 kV line.
- Danone's Dairy Processing plant at Greenfield is supplied via a 33 kV spur line that connects to one of the two Charlotte Street to Clydevale lines. A 33 kV voltage regulator at Greenfield substation controls the voltage fed to 33,000/415V distribution transformers.
- Pan Pac's wood processing plant at Milburn is supplied by a dedicated underground 11kV feeder cable from Milburn zone substation.

A developing trend is for large customers doing process heat energy source conversions to request a lower level of security to their plant. This takes the form of N security or interruptible load. A typical example is a plant where boilers are used to generate steam. In many of these plants the process allows the power supply to be interrupted for relatively long periods of time while the boiler acts as an energy storage device. Steam can still be used to finish a production cycle. The SAIDI and SAIFI treatment under these scenarios is unclear, but as it is a single customer that gets affected, the impact is not material.

Secondary Customer Service Levels

Secondary service levels are the attributes of service that OJV customers have ranked below the first and second most important attributes of supply continuity and restoration. The key point to note is that some of these service levels are process driven which has two implications:

- They tend to be cheaper than fixed asset solutions e.g. staff could work a few hours overtime to process a back log of new connection applications and could divert an over-loaded phone, or OJV could improve the shut-down notification process.

[8] Formerly Trustpower

- They can be provided exclusively to customers who are willing to pay more, in contrast to fixed asset solutions which will equally benefit all customers connected to an asset regardless of whether they pay.

These attributes include how satisfied customers are with communication regarding tree trimming, connections or faults, the time taken to respond to and remedy justified supply quality complaints and the amount of notice before planned shutdowns. Table 43 sets out targets for these service levels for the next ten years.

Table 43: Secondary Service Level Projections

Attribute	Measure	2023/24	2024/25	2032/33
Planned Outages	Provide sufficient information. {CES}	>80%	>80%	>80%
	Satisfaction regarding amount of notice. {CES}	>80%	>80%	>80%
	Acceptance of one planned outage every two years lasting four hours on average. {CES}	>75%	>75%	>75%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES}	>50%	>50%	>50%
	No impact or minor impact of last unplanned outage. {CES}	>70%	>70%	>70%
	Information supplied was satisfactory. {CES}	>70%	>70%	>70%
	PowerNet first choice to contact for faults. {CES}	>50%	>50%	>50%
Supply Quality	Number of customers who have made supply quality complaints. {IK}	<20	<20	<20
	Number of customers having justified supply quality complaints. {IK}	<15	<15	<15

{} indicates information source; CES = Customer Engagement Survey using independent consultant to undertake phone survey, IK = Internal KPIs.

Other Service Levels

In addition to the primary and secondary service levels described in the sections above, there are a number of service levels that benefit stakeholders. These include safety, amenity value, absence of electrical interference, and performance data as presented in Table 44. Many of these service levels are imposed on OJV by statute and while they are for the public good – i.e., necessary for the proper functioning of a safe and orderly community – OJV absorbs the associated costs into its overall cost base.

Table 44: Other Service Levels

Service Level	Description
Safety	Various legal requirements require OJV's assets (and customer's plant) to be compliant to safety standards which include earthing exposed metal and maintaining specified line clearances from trees and from the ground: • Health and Safety at Work Act 2015. • Electricity (Safety) Regulations 2010 • Electricity (Hazards from Trees) Regulations 2003. • Maintaining safe clearances from live conductors (NZECP34 or AS2067). • EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.

Amenity Value	OJV is limited by several Acts and other requirements in the adoption of overhead lines. • The Resource Management Act 1991. • The Operative District Plans. • Relevant parts of the Operative Regional Plan. • Land Transport requirements. • Civil Aviation requirements. • Land Transfer Act 1952 (easements)
Industry Performance	The Commerce Act 1986 empowers the Commerce Commission to require OJV to compile and disclose prescribed information to specified standards.
Electrical Interference	Under certain operational conditions OJV's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or OJV's own equipment. The following publications are used to prevent issues from interference: • Harmonic levels (NZECP 36:1993). • Single wire earth return limitations (EEA High Voltage SWER Systems Guide). • NZCCPTS: coordination of power and telecommunications (several guides).

5.2 Regulatory Service Levels

Various Acts and Regulations require OJV to deliver a range of outcomes within specified timeframes, such as the following.

- Ensure customer satisfaction with both pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose an AMP each year.
- Publicly disclose prescribed performance measures each year.

In addition to these requirements, OJV is also required to disclose a range of internal performance and efficiency measures as required by the **Error! Reference source not found.**. Previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008. The complete listing of these measures is included in OJV's disclosure of 31 March 2022 and available at https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors.

Financial Efficiency

OJV Financial efficiency falls into two groups, namely:

- Network OPEX metrics; and
- Non-Network OPEX metrics.

For effective benchmarking, OPEX metrics need to be measured against the relative size of another EDB. A single fair measure of the "size" of an EDB is not available, therefor OJV adopted the following measures from Information Disclosure Schedule 1.

- Interconnection Points (ICPs) as at year end.

- Total km network length.
- Total MVA of EDB-owned distribution transformer capacity.

OJV has six financial efficiency targets as shown in Table 45.

Table 45: Financial Efficiency Targets

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2023/24	$251	$1,092	$21,453	$198	$859	$16,873
2024/25	$251	$1,092	$21,453	$198	$859	$16,873
2025/26	$251	$1,092	$21,453	$198	$859	$16,873
2026/27	$251	$1,092	$21,453	$198	$859	$16,873
2027/28	$251	$1,092	$21,453	$198	$859	$16,873
2028/29	$251	$1,092	$21,453	$198	$859	$16,873
2029/30	$251	$1,092	$21,453	$198	$859	$16,873
2030/31	$251	$1,092	$21,453	$198	$859	$16,873
2031/32	$251	$1,092	$21,453	$198	$859	$16,873
2032/33	$251	$1,092	$21,453	$198	$859	$16,873

* Dollar values as constant 2023 dollars.

Energy Efficiency

Energy delivery efficiency measures are the following.

- **Load factor** – [kWh entering OJV's network during the year] / [[max demand for the year] x [hours in the year]].
- **Loss ratio** – [kWh lost in OJV's network during the year] / [kWh entering OJV's network during the year].
- **Capacity utilisation** – [max demand for the year] / [installed transformer capacity].

Projected energy efficiency forecasts and targets are shown in Table 46. Changes in peak management requirements have impacted the load factor.

Table 46: Energy Efficiency Targets

Measure	2023/24	2024/25	2025/26	…	2032/33
Load Factor	79%	79%	79%	…	79%
Loss Ratio	5.0%	5.0%	5.0%	…	5.0%
Capacity Utilisation	30%	30%	30%	…	30%

5.3 Service Level Justification

OJV's service levels are justified as we have following conditions.

- Customers have indicated preference for paying the same line charges for the same service levels.
- Improvements provide positive cost benefit within revenue capability.
- Customers make specific requests to receive a different mix of reliability and pricing from what would otherwise be available. E.g., customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- External agencies impose service levels either directly or indirectly where an unrelated condition or restriction manifests as a service level e.g., a requirement to place all new lines underground, or a requirement to increase clearances, or cost recovery allowances do not permit renewal rates.
- Customer expectations of service levels set by historic investment decisions and resultant network performance.

Over the last four years customer surveys indicated that preferences for price and service levels are reasonably constant and a general requirement for increased supply reliability is absent. However, the following challenges exist.

- The default price-quality path methodology requires "no material deterioration" in network reliability and now includes a revenue incentive for improving reliability.
- The service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- OJV's cold storage customers require higher levels of continuity and restoration with interruptions to cooling and chilling being less acceptable as food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets.
- Economic downturn may increase the incidence of theft of materials and energy.

5.4 Service Level Target Setting

Service level targets are based on historical trends and benchmarking against other local distribution networks. These aspects are described in the following sections.

Historical Trends

In setting service level targets the recent history of service level measures are considered. These measures are slow to change and not easy to influence. Trends are determined from the historic results and then projected to forecast future service levels. Projections are adjusted to rationalise initiatives or other issues that might affect service levels.

Network reliability, financial and energy efficiency targets are generally based on forecast levels to support performance enhancement initiatives. Targets for customer satisfaction are based on the desired outcome of achieving positive customer experiences. Results from the last five years for reliability, energy efficiency targets and customer satisfaction outcomes from past surveys are listed in Table 47.

Table 47: Reliability and Energy Efficiency History

Measure	2017/18	2018/19	2019/20	2020/21	2021/22
SAIDI	233.2	235.6	242.7	322.3	270.6
SAIFI	2.87	2.59	2.26	2.66	3.16
Load Factor	79%	76%	79%	80%	79%
Loss Ratio	3.5%	4.0%	4.1%	4.6%	4.4%
Capacity Utilisation	27.4%	26.6%	25.7%	25.0%	28.5%
Network OPEX / ICP	$298	$334	$330	$292	$283
Network OPEX / km	$1,040	$1,201	$1,229	$1,128	$1,135
Network OPEX / MVA	$24,505	$25,848	$25,591	$23,452	$22,850
Non-Network OPEX / ICP	$157	$189	$184	$207	$189
Non-Network OPEX / km	$546	$679	$687	$798	$755
Non-Network OPEX / MVA	$12,859	$14,610	$14,297	$16,585	$15,208

DPP3 encourages EDB's to do move towards doing more planned work and in so doing to change the ratio between planned and unplanned work. This is done by setting planned work limits and incentivising planned work by allowing deductions on SAIDI minutes for notified planned interruptions. OJV is taking advantage of this opportunity by increasing the Routine and Corrective Maintenance and Inspection Operating Expenditure budget as well as increasing the 11kV Cable Replacement allocations in the Capital Expenditure Forecasts. This will lead to an increase in planned work and planned interruptions and will in the longer term have a positive impact on unplanned interruptions. This will be assisted by the increase in the Network Automation budget that will allow faster restoration of power under fault conditions. The overall impact will be an increase in planned SAIDI and SAIFI but a decrease in the unplanned figures.

Table 48: Customer Satisfaction History

Attribute	Measure	2017/18	2018/19	2019/20	2020/21	2021/22
Planned Outages	Provided sufficient information {CES}	91%	93%	92%	94%	92%
	Satisfaction regarding amount of notice {CES}	99%	98%	96%	95%	99%
	Acceptance of one planned outage every two years lasting four hours on average {CES}***	62%	66%	55%	-	91%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time {CES}*	-	-	-	-	68%
	No impact or minor impact of last unplanned outage {CES}***	78%	69%	67%	73%	60%
	Information supplied was satisfactory {CES}*	78%	86%	78%	54%	75%

Attribute	Measure	2017/18	2018/19	2019/20	2020/21	2021/22
	PowerNet first choice to contact for faults {CES}**	38%	34%	26%	37%	35%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	1	2	0	7	6
	Number of customers having justified supply quality complaints {IK}	1	2	0	6	4

{} indicates information source: CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

* As these questions are limited to customers experiencing an unplanned outage in the last six months, the sample size is very small for a network as reliable as OJV. This can lead to substantial year-to-year fluctuations.

**Noting that each year a substantial proportion of responses (72% in 2017/18) simply state that the customer would not call anyone.

***Survey questions were changed from the 2017/18 surveys and onwards. The modified questions provided a wider range of options compared to previous surveys, which has influenced the response

Benchmarking

Benchmarking against other local distribution networks assist with the identification of potential improvements in the current service levels that OJV offers. Comparisons with Alpine Energy, Electricity Ashburton, Marlborough Lines, OtagoNet, The Lines Company and The Power Company are useful as these networks are like OJV in terms of density and asset base. Several indicators are benchmarked against other EDB's performance in Chapter 10.

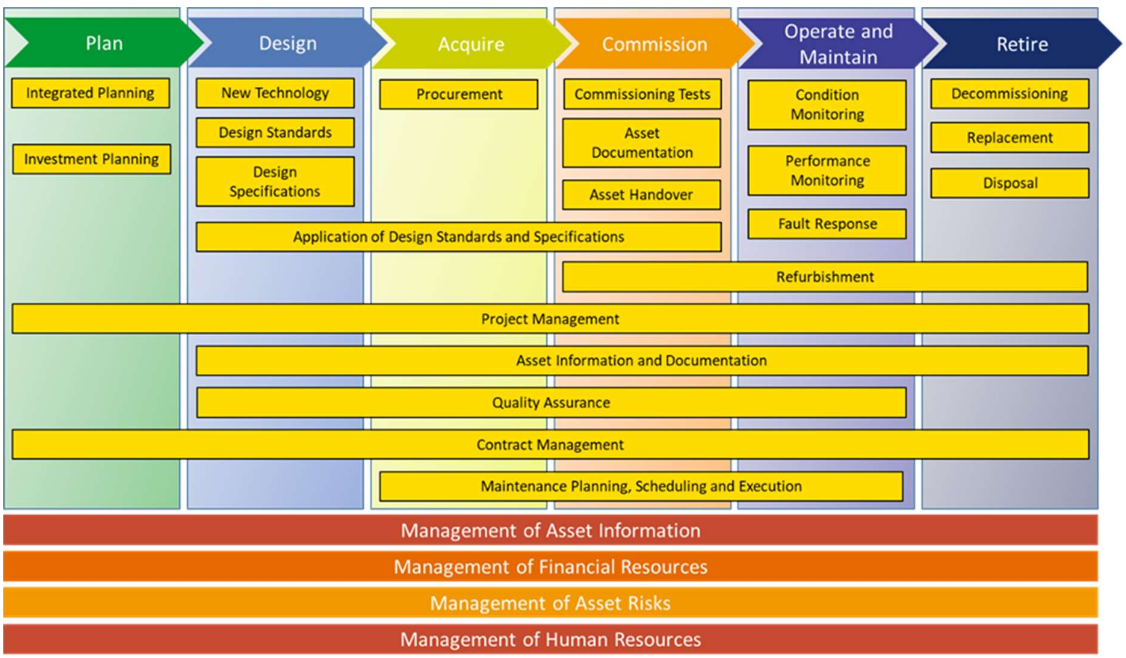
6 Asset Management Strategy

The Asset Management Strategy was described in the 2023-33 AMP:

OJV's Asset Management Strategy is based on PowerNet's asset management model (focusing on a lifecycle management approach). The strategy is structured to address the main activities and challenges faced in each lifecycle stage as well as the support processes. It defines objectives for each activity and recommends initiatives to achieve the stated objectives. In each case, responsibilities are defined and realistic timeframes are suggested. Figure 44 charts the various asset lifecycle stages and support processes that cut across the entire value lifecycle.

The defined strategic objectives and initiatives are aligned with the relevant stakeholder' business plans. These are aimed at achieving continuous business improvements through balancing risk, performance and cost.

Figure 44: Lifecycle Model for Asset Management



6.1 Lifecycle Stages

The asset lifecycle stages are described in the following sections.

Planning

The function of network planning ensures that the optimal expansion of the power system can sustain demand. Expansion needs to occur at the right time to balance optimal investment of capital, but at the same time avoid network overloading. The power network needs to continuously meet power quality, reliability, statutory, safety and environmental requirements.

The planning philosophy is that least economic (lifecycle) cost be implemented. This entails decision-making to balance CAPEX and OPEX spending. There should be a formal correlation between capital planning (CAPEX) and maintenance planning (OPEX) and the investment in assets should produce the expected network reliability and performance. The major strategic objectives for network planning are the following.

- Asset planning and management are the foundation of OJV's business plan and enable the integration of CAPEX and OPEX budgets.
- Planning for network expansion, strengthening and/or refurbishment is based on whole life cost.
- Planning incorporates the connection of new customers.
- Capital projects are prioritised based on risk.

Plant or Network Design

The design lifecycle stage includes the design and specification of plant, as well as the design and engineering of the power network. There are several standards and guidelines available that covers the design and engineering of the power network. PowerNet creates and maintains many accessible standards, specifications and guidelines for power as well as control plant. Where an internal standard is not available, PowerCo standards are used.

Standards and specifications are often developed around technical, safety, environmental and statutory requirements without considering lifecycle cost, maintenance, risk or reliability necessities. Spares distribution and asset disposal arrangements are often also not considered during the design and/or specification of a specific asset. This is contrary to our Asset Management Policy which focuses on the full life cycle of assets. OJV's major strategic objectives for the Design lifecycle are the following:

- Efforts are focused on improving asset life and performance while minimising cost and risk.
- Equipment standards and designs support network reliability and performance at lowest lifecycle cost and risk.

Acquisitioning

The acquisitioning stage includes the procurement of new plant and equipment (based on specifications developed during the design stage). It also includes obtaining construction services from contractors. This is followed by activities such as project management, contract management, construction and/or installation of the asset and quality assurance. This lifecycle stage is supported by PowerNet's commercial services and supply chain processes.

The physical construction and installation of assets are critical activities that influence the life expectation and lifecycle cost of a specific asset. Incorrect construction and installations can lead to equipment failures. This makes quality assurance in terms of both equipment and installation of vital importance. The following major strategic objectives for the acquire lifecycle stage were identified.

- Procurement Policies support lifecycle costing and risk management.
- Construction and installation quality will not compromise the asset life.

Commissioning

The commissioning phase starts when the contractor has completed the implementation of an asset or plant (based on the design stage) and indicates that the asset or system is ready for utilisation. Final testing of the installation needs to be carried out, the as-built data be recorded/captured and the maintenance as well as operating staff needs to be instructed in the requirements of the new plant. The phase ends when the new asset is put into commercial operation. The following are OJV's major strategic objectives for the commissioning lifecycle stage.

- The quality of networks and assets handed over for operation is to specification.
- As-built documentation and records are properly generated and managed.
- Maintenance requirements are well understood, maintenance staff have been trained and the required manuals, tools and equipment are available.

Operate & Maintain

During the operate and maintain lifecycle stage, physical assets are expected to perform their designed function at (or above) the specified performance and reliability parameters. Operating and maintenance practices greatly influence the performance, reliability and life expectancy of the asset. Good management of assets during this lifecycle phase will extend life expectancy, reduce overall lifecycle costs and ensure availability and reliability. When there is collaboration between asset operators and maintainers, the best performance (at the optimum cost) of the asset will be experienced. Deterioration and poor performance are often the result if either operations or maintenance teams work in isolation of each other. The following are OJV's major strategic objectives for the O&M lifecycle stage.

- Assets are operated and maintained in a manner that minimises system lifecycle cost with consideration of risk.
- Electricity delivery networks and associated electrical systems are maintained in such a manner that the requirements of customers, internal stakeholders and legal authorities are met at minimum lifecycle cost.
- Defect and liability periods as well as equipment guarantees are documented and managed.

Retire

This lifecycle stage includes the following potential activities.

- **Replacement** – The planned replacement of assets for reasons other than system expansion e.g., degraded performance experienced at the end of its useful life.
- **Retirement** – The removal of equipment from service due to system expansion, but retention of the asset for strategic reasons such as spares.
- **Disposal** – The complete removal and disposal of an asset when it is no longer required.

OJV's major strategic objectives for the retire cycle stage are the following.

- Assets' replacement decisions are based on reliability, operating cost, condition and predicted end-of-life.
- Asset disposal will create minimal long-term safety risks or risks to the environment.

6.2 Lifecycle Support

Lifecycle support activities are described in the following sections.

Management of Asset Risks

Risk Management can be defined as:

> *"The continuous, proactive and systematic process to understand, manage and communicate risk from an organisation-wide perspective. It is about making strategic decisions that contribute to the achievement of an organisation's overall corporate objectives. Risk refers to the uncertainty that surrounds future events and outcomes. It is the expression of likelihood and impact of an event with the potential to influence the achievement of an organisation's objectives."*

Risk is the product of "*consequence*" and "*probability*". Consequence refers to the potential impact of a failure incident on the business. In the context of asset management, this relates to the criticality (its importance to the business) of each asset. Risk is not limited to a single stage in the asset lifecycle, but cuts across all the phases. Risk Management is applied to all relevant business activities and is the fully inclusive basis for prioritising all activities, including engineering projects and investments.

Management of Asset Information

PowerNet has very good information systems but several information related projects overlap and overall prioritisation and co-ordination are lacking. This leads to unnecessary expenditure and inefficiencies. In addition, the selection and implementation of information systems are mostly focused on financial and regulatory compliance and asset management requirements are not sufficiently addressed.

Integration between asset management information systems (e.g., MAXIMO, FINANCE 1 and GIS) is inadequate and the use of decision support tools are therefore restricted. In the design of systems such as Maximo, the focus was mostly on primary plant information, while the requirements for secondary plant information have been largely overlooked. Data accuracy and completeness thereof is generally inconsistent.

The strategic objectives for asset information management are the following.

- Asset management information systems shall link asset history, technical design, performance and risk information, as well as financial data of individual assets.
- Data and information shall be consistent across all systems.

Management of Human Resources

Effective asset management requires that personnel responsible for the design, construction, operation and management of assets have appropriate education, training and/or experience. Procedures should be in place to ensure that employees or third parties such as contractors are aware of the following.

- The importance of compliance with the requirements of the asset management system, including the asset management policy, processes and procedures.
- Their roles and responsibilities in achieving compliance including emergency preparedness and response requirements.
- The potential consequences of deviating from stipulated operating procedures.
- Long-term asset management training requirements need to be identified and adequately planned for.

Like most industries in New Zealand and world-wide, PowerNet is experiencing some shortages in skilled roles. As Network Manager, PowerNet is responsible to ensure they can resource the business, through their internal and contracted resources, to deliver across the Networks they manage. Through various short-, medium- and long-term strategies, PowerNet will manage resourcing to ensure they deliver.

The strategic objective for the management of human resources is that: - *the necessary resources and skills to plan, acquire, operate and maintain the assets that PowerNet manage, be attracted, developed, retained and be available when required.*

Management of Financial Resources

Financial resources are required to manage assets efficiently over their entire lifecycle. Asset management requires processes for defining and capturing as built, maintenance and renewal unit costs and methods for the valuation and depreciation of its assets. Unfortunately, the Operating and Maintenance budget is often cut when an organisation is facing financial constraints.

The following is the major strategic objective for the management of financial resources: - *the necessary financial reporting to plan, acquire, manage, operate, and maintain PowerNet's managed assets shall be developed, and finances made available when required.*

6.3 Lifecycle Management and Growth

Growth is the increase in the demand for electricity, either due to an increase in the number of customers or to an increase in demand by a single customer, or a combination of both. Customers are considering electricity as an alternative to coal or other carbon-based fuels due to the drive towards cleaner sources of energy in industrial processes. Supplying this increased demand often requires utilisation of the full spare capacity of network. Redesign and development of networks are needed to accommodate these load increases.

Maintenance (and operation) of assets is the prominent lifecycle process post installation (commissioning). Maintenance can be defined as a combination of all technical and administrative actions (including supervisory actions), intended to retain an asset in, or restore it to a condition that allows it to perform a required function. Maintenance does not extend the life of an asset or increase its capacity, but it is an essential function to ensure that an asset reaches its expected life.

There is a correlation between network development, lifecycle management practices and network service levels. Over time, supply reliability is impacted by the increased demand on fixed network assets. More customers and associated service levels are affected with supply interruptions. In the long-term, lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration. Similarly, network development offsets declining reliability when demand growth occurs.

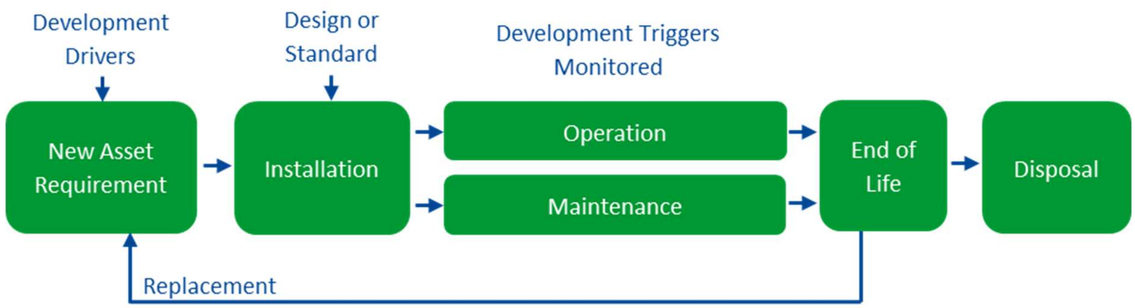
6.4 Lifecycle Management Processes

OJV adheres to several asset management processes to manage network assets throughout the lifecycle stages. Following procurement of equipment and materials, assets are constructed or installed as per design or a specific network standard. The commissioning process ensures that the asset can operate as intended. From there, the asset enters its service life (useful life) during which it will be operated (usually over a considerable period). In general, maintenance activities are undertaken throughout an asset's operational life to support ongoing reliability while it is economically feasible to do so. The maintenance drivers over the lifecycle of an asset are the following.

- Support continued reliable service to customers.
- Economic viability when compared to replacement.
- Continued safety.
- Operational efficiency.
- Rate and extent of deterioration.
- Criticality.
- Probability of failure.

At some point in the future, an asset will reach its end of life and will be retired from service. The asset will be replaced if the need remains. The retired asset will responsibly and appropriately be disposed of. This process is outlined in Figure 45.

Figure 45: Lifecycle Management Processes



6.5 Fleet Plans

A Fleet Plan is a description of how a specific asset or type of asset will be managed over its entire lifecycle. For each asset the material cost and time required to execute the following activities, need to be determined.

- Installation of the asset.
- Execution of each type of maintenance action, as well as the time interval between the activities.
- Decommissioning and disposal of the asset.

Through the development of Fleet Plans, OJV can:

- determine capital funding requirements for the next 10-20 years.
- establish the number of people required, their skill levels and equipment needed to operate and maintain the electricity networks for the next 10-20 years.
- determine operational expenditure requirements for the next 10-20 years; and
- plan for accessing all network assets within a reasonable period for testing and maintenance.

These requirements are aggregated across the Annual Works Program for each CAPEX and OPEX category.

7 Capital Expenditure

7.5 2024-34 Update Capital Expenditure Forecast

The capital expenditure forecast is presented in Table 49 and provided in the Information Disclosure Schedule 11a.

Table 49: 2024-34 Update Capital Expenditure Forecast ($000 – constant 2024/25 terms)

Category	DPP3	DPP4					DPP5			
CAPEX: Consumer Connection	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Customer Connections (≤ 20kVA)	1,101	966	966	966	966	966	966	966	966	966
Customer Connections (21 to 99kVA)	171	171	171	171	171	171	171	171	171	171
Customer Connections (≥ 100kVA)	354	354	354	354	354	354	354	354	354	354
Major New Connections Projects	3,788	5,341	5,642	5,123	4,920	4,938	4,944	4,920	4,920	4,920
	5,413	**6,831**	**7,132**	**6,613**	**6,410**	**6,428**	**6,434**	**6,410**	**6,410**	**6,410**

CAPEX: System Growth	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Patearoa Substation Upgrade	1,505	1,019								
Puketoi Area Regulator & Line Upgrade		285								
Easements	6	6	6	6	6	6	6	6	6	6
Milton Area Capacity Upgrade				230						
Maniototo Road-Lower Gimmerburn 11kV Line		205								
General LNL Network Growth		152	152	152	152	152	152	152	152	152
New Zone Substation Land					864					
QLDC Arterial (CBD)	38									
Kawarau South Bank Cable & Southern Corridor	424			998	998	998				
Frankton Road 22kV Extension	424	806	343							
Southern Corridor Zone Substation					690	13,787				
Unspecified System Growth Projects							2,274	1,137	1,137	1,137
	2,397	**2,473**	**502**	**1,387**	**2,712**	**14,944**	**2,432**	**1,295**	**1,295**	**1,295**

CAPEX: Asset Replacement and Renewal	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
LV Line Replacement and Renewal	904	904	904	904	904	904	904	904	904	904
SWER Line Replacement and Renewal	602	602	602	602	602	602	602	602	602	602
11 kV Line Replacement and Renewal	3,709	3,709	3,709	3,709	3,709	3,709	3,709	3,709	3,709	3,709
33 kV Line Replacement and Renewal	1,232	2,063	2,221	2,221	2,221	2,221	2,221	2,221	2,221	2,221
Zone Substation Minor Replacement	100	100	100	100	100	100	100	100	100	100
Relay Replacements	185	381	469	137	282	279	44	367	17	17
Distribution Transformer Replacements	182	182	954	954	954	954	954	954	954	954
Quarry Road Substation		455	11,184		388	307				
Owaka 11 kV Switchgear Replacement			270	3,236						
Kaitangata 11 kV Switchgear Replacement						270	2,124			
Clinton 11 kV Switchgear Replacement						270	2,415			

Halfway Bush – Palmerston 33kV Towers Refurbishment	63	789	306							
Palmerston Zone Sub 11 kV switchgear replacement			270	3,088						
Waitati Zone Sub Relocation (Blueskin Bay)				246	11,153	372				
Elderlee Street 11 kV Switchgear Replacement			309	3,152						
Remarkables Substation 22kV Switchboard Replacement				864						
SWER Recloser Replacements	164									
Maximum Demand Indicator Upgrade	20	202	182	182	182					
ABS Renewals	235	235	288	288	288	288	288	288	288	288
Glenore Substation Supply Reconfiguration				854						
North Balclutha 11 kV Switchgear Replacement						270	2,721			
Finegand 11 kV Switchgear Replacement							270	2,154		
Ranfurly & Paerau Powerhouse Relay Replacements	127	795								
Circuit Breaker Replacements		584				219		603		
Ranfurly 11 kV Switchgear Replacement								270	3,387	
Waihola 11 kV Switchgear Replacement									270	2,329
Power Transformer Refurbishment				139			139			
Power Transformer Replacements	135	105								
RTU Replacements		22	117	77	110	33	88	55		
Distribution – General	31	31	31	31	31	31	31	31	31	31
Paerau Powerhouse 66kV line insulator replacements	894									
Unspecified Replacement & Renewal Projects								2,890	2,978	4,306
	8,585	**11,161**	**21,916**	**20,785**	**20,924**	**10,830**	**16,612**	**15,148**	**15,462**	**15,462**

CAPEX: Asset Relocations	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Network Chargeable Capital	38	38	38	38	38	38	38	38	38	38
Milton Main Street Undergrounding	1,433									
	1,471	**38**	**38**	**38**	**38**	**38**	**38**	**38**	**38**	**38**

CAPEX: Quality of Supply	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Finegand 33kV smart network automation		1,434								
Supply Quality Upgrades	13	13	13	13	13	13	13	13	13	13
Network Improvement Projects		195	148							
Mobile Substation site made ready			313		313	313	627	313		
Northlake to Clearview Link Cable		152								
RMU SCADA & Communications			31	31	31	31	31	31	31	
Reliability & Resilience Projects							5,000	5,000	5,000	5,000
	13	**1,794**	**505**	**44**	**357**	**357**	**5,671**	**5,357**	**5,044**	**5,013**

CAPEX: Legislative and Regulatory	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CAPEX: Other Reliability, Safety and Environment	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Substation NERs and 33kV Transformer Circuit Breakers	100	271								
Communications Upgrade			120	1,266	1,266					
Replacement of OH Structures with Ground Mounted		248	248	248	248	248	248	248	248	248
Earth refurbishment from earth testing, incl. SWER	701	759	729	541	541	497	238	238	238	238
Critical Spares		60								
Ranfurly Transformers Oil Containment & Seismic Strengthening				185						
Hyde Transformer Oil Containment & Seismic Strengthening					142					
	802	**1,338**	**1,097**	**2,239**	**2,197**	**745**	**486**	**486**	**486**	**486**

Total Network CAPEX	18,680	23,636	31,191	31,107	32,639	33,341	31,673	28,735	28,735	28,705

CAPEX: Non-Network Assets	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Values Fully Marked Up, No Inflation, Base Year dollars.

The projects and reasoning as well as the 2023-33 forecast were described in the 2023-33 AMP:

Capital Expenditure (CAPEX) is required to increase the capacity of assets or networks, to extend the life of assets, to install new assets for safety or reliability purposes or to replace aging assets. CAPEX is categorised according to ComCom requirements as follows:

- Consumer Connection.
- System Growth.
- Asset Replacement and Renewal.
- Asset Relocations.
- Reliability, Safety and Environment.

7.1 Asset and Network Load Growth Planning

Long term asset and network expenditure requirements are determined in the planning asset life cycle stage. The following aspects are considered during this phase:

- Network configuration.
- Asset and asset system redundancy.
- Capacity of the assets and the systems.

OJV monitors the existing network assets and ensures that they operate within limits imposed by capacity constraints and service level requirements. Regular updating of demand forecasts enables predictions for future network operation and in line with OJV's development criteria helps identify the need for network development.

Planning Phase Risks

The following risks are addressed during the planning phase.

Table 50: Planning Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment
Operational Performance	**Damage due to extreme High Impact Low Probability (HILP) Physical Event**	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Determining areas prone to physical events such-as earthquake (liquefaction), tsunami and flood zones Plan networks to avoid high probability HILP event areas
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Environmental scans to determine potential growth industries and geographical growth areas Determine the impact of potential technology changes on the networks, e.g. electrification of fossil fuel process heat, distributed generation as well as changes in distribution asset technology Plan the networks to cater for the envisaged growth and technology changes
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	4 year project planned to upgrade links - due for completion 2029
	Loss of right to access or occupy land	Risk of assets losing / not having the right to occupy particular locations (e.g. aerial trespass, subdivision)	Plan any new networks along public service corridors as far as possible. Ensure that rights of way and easements are obtained as part of the planning process
Health and Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Plan the networks and asset locations to reduce the probability of incidents to a minimum

Network Development Drivers

EDBs across New Zealand are aware that they have a key role to play as their networks enable the decarbonisation and electrification of society, particularly in the transport and industrial sectors. As EDBs confront this challenge, they recognise the importance of providing clear signals to their customers, communities and other stakeholders, of the likely medium to long term implications of this transition. It is important for stakeholders to understand that this is not 'just' an electric vehicle story – different EDBs will experience increased demands for investment in their networks for a range of different reasons. The following paragraphs describe what are anticipated to be the most significant sources of this demand that OJV anticipates will occur over the next three decades, out to 2050. It should be noted that for many EDBs, ongoing 'business as usual' maintenance and renewal of their existing distribution network is, and will continue to be, a very significant driver of investment, however this is not presented here as it is not a 'new' driver of investment of the type the sector wishes to highlight. Lastly, readers should appreciate that while certain elements of the transition are well-understood and reasonably well-fixed (e.g. the net zero by 2050 target), other elements which may have a significant impact on EDBs (e.g. the phase-out of reticulated gas for home heating, hot water and cooking), are still uncertain. OJV has made an educated assessment of what might be expected on their network, but there are significant uncertainties and assumptions built into this. The EDB sector will, via its association the Electricity Networks Association, be developing a more rigorous and structured set of demand forecasts and scenarios out to 2050 in the coming months.

Development demands include the following:

- Large generation or an aggregation of small generators may require increased capacity on some areas of the network.
- Requirements for maintaining or improving service levels (whether statutory, customer and other stakeholders' needs or internal strategic initiatives).
- A connection request from an intending customer requires an increase in network capacity to match their additional load requirements.
- When load growth exceeds a threshold for increased security – the threshold is based on a predetermined strategic "line in the sand" which is designed to provide particular service levels when applied consistently across the network.
- While asset renewal is generally a lifecycle management requirement, it may present an opportunity as the most economic time for development initiatives such as additional capacity, the introduction of new technology, or more efficient alternative solutions.

Development projects can take many months or even years to complete, therefore a good understanding of trigger points and when they may be exceeded in the future is required. This is to ensure that capacity can be made available by the time it is needed. The network development process involves demand forecasting (based on historical trends) as well as consideration of the various demand drivers which may cause deviation from status quo trends. Some of these trigger points are discussed below.

Customer Behavioural Changes

While many factors could change our future operating environments, of particular importance is the way our customers will use, generate and manage energy in the future. Our approach is to understand and address changing customer requirements and energy use patterns. These changes on the customer side will likely be driven by a combination of factors, including the increased use of new technology (including own generation, electric vehicles and new types of appliances), increasing efforts to reduce carbon emissions, and an ongoing drive to reduce energy costs. We have a responsibility to help facilitate these changes, allowing our customers to achieve their goals.

Effective demand management, energy storage and tariff incentives will help maximise the utilisation of existing energy infrastructure and defer or minimise future investment. Electricity should also offset other, less environmentally friendly, forms of energy, and the network should facilitate this, for example electric vehicles offsetting the demand for petroleum.

Transitioning to this future will require considerable effort and investment in providing the required visibility, controllability, flexibility and stability of all parts of the network – particularly in LV networks where the needs and impacts will be most severe. However, the timing at which this investment will be required is highly uncertain.

Declining costs of distributed energy resources and increasing digitisation and smart technology will drive a more distributed electricity system. Declining costs of distributed energy resources (DER): As the cost of DER, such as residential and commercial solar and batteries decline, their uptake is forecast to increase significantly. Between 2010 and 2020, the cost of a residential solar PV system declined by 65%, with a further decline of 60% predicted in the 2020s, according to the National Renewable Energy Laboratory (NREL). NREL also predicts residential batteries will continue declining in cost, reducing by up to 50% this decade. While purchased primarily for their transport services, EVs can also act as DER across networks.

New smart technologies like automation, AI, Internet of Things (IoT), real-time communication, and network visibility by household will revolutionise the way electricity systems are operated. As technology improves and the cost of IoT sensors decline, it is likely that millions of DER will be able to interact in real-time with the electricity system. This provides a significant opportunity to increase consumer participation in markets and more effectively manage complex multi-directional electricity flows that will emerge in future. Energy system changes due to a more distributed electricity system Increased need for system smarts to integrate DER: DER – such as such as rooftop solar, battery storage, EVs, hot water systems, smart appliances, smart meters, and home energy management technologies – will play an important role in New Zealand's decarbonisation.

Ongoing Electricity Demand Growth (residential, commercial, and industrial)

The majority of our customers continue to use centrally generated electricity as their key energy source. We do not predict this changing significantly in the foreseeable future. Importantly, our networks provide the "last mile" connection to customers. Even when renewable generation or grid-connected energy storage becomes much more widespread, it would not reduce customers' reliance on our networks to access these. Likewise, to fully realise the potential benefit of locally generated electricity, customers will still need the distribution network to export their excess electricity, or to import at lean times. Therefore, it would be imprudent to materially adjust investment and asset management plans now to make provision for uncertain needs that may arise in future. For the AMP planning period, we see most of our network expenditure remaining on conventional electricity network assets and practices. Accordingly, we will continue to keep a strong focus on the health, capacity and operation of our existing network, as well as expand the network to meet the increased demand of new – and existing – customers. In terms of this AMP, it means that investment on asset renewal, maintenance and growth of conventional network assets will also remain paramount.

Electrification of Transport

Road transport accounts for about 17% of carbon emissions in New Zealand. The electrification of these fleets, starting with passenger vehicles, is therefore another obvious focus area to reduce emissions in New Zealand. While current uptake of EVs is relatively low, we expect it to accelerate, especially if more government incentives emerge to support this. The impact of increasing numbers of EVs on electricity demand is highly uncertain, as it is subject to multiple factors such as:

- Number of EVs in a network area.
- Average distance travelled per day (and hence energy required to recharge).
- Use of charging infrastructure structure (public infrastructure v residential charging).
- Time of charging (off-peak charging will have little impact, but should it coincide with the early evening demand peak, it will add to total network demand).
- Energy required by the type of vehicle.
- Rate of charging.
- The expected demand increase can be largely avoided if we can encourage charging during off-peak hours. Various means of achieving this are being investigated.

Demands for decarbonisation

One of the main focus areas for reducing New Zealand's carbon footprint is the decarbonisation of process heat. Industrial processes and waste represent about 11% of New Zealand's carbon emissions.

When point demands start to exceed about 30MVA, it becomes generally impractical or uneconomic to connect to distribution networks, even at 33kV. Direct grid connections are generally necessary, even where these may still be provided by distribution utilities. Where large processes are electrified, we therefore foresee that these will be directly connected to the transmission grid. However, there are still significant numbers of smaller industrial and commercial heat processes, such as heating for hospitals and schools, operating at lower temperature levels, where converting to electricity from current carbon-based heat sources is viable. At least part of the additional electricity capacity required to achieve this will be drawn from distribution networks. As the pressure on business and other entities to reduce emissions increases, we see potential for significantly higher electricity demand associated with process heat conversion. This impact can be even more substantial on those parts of our network where heat loads are concentrated.

Greater reliance on renewable energy

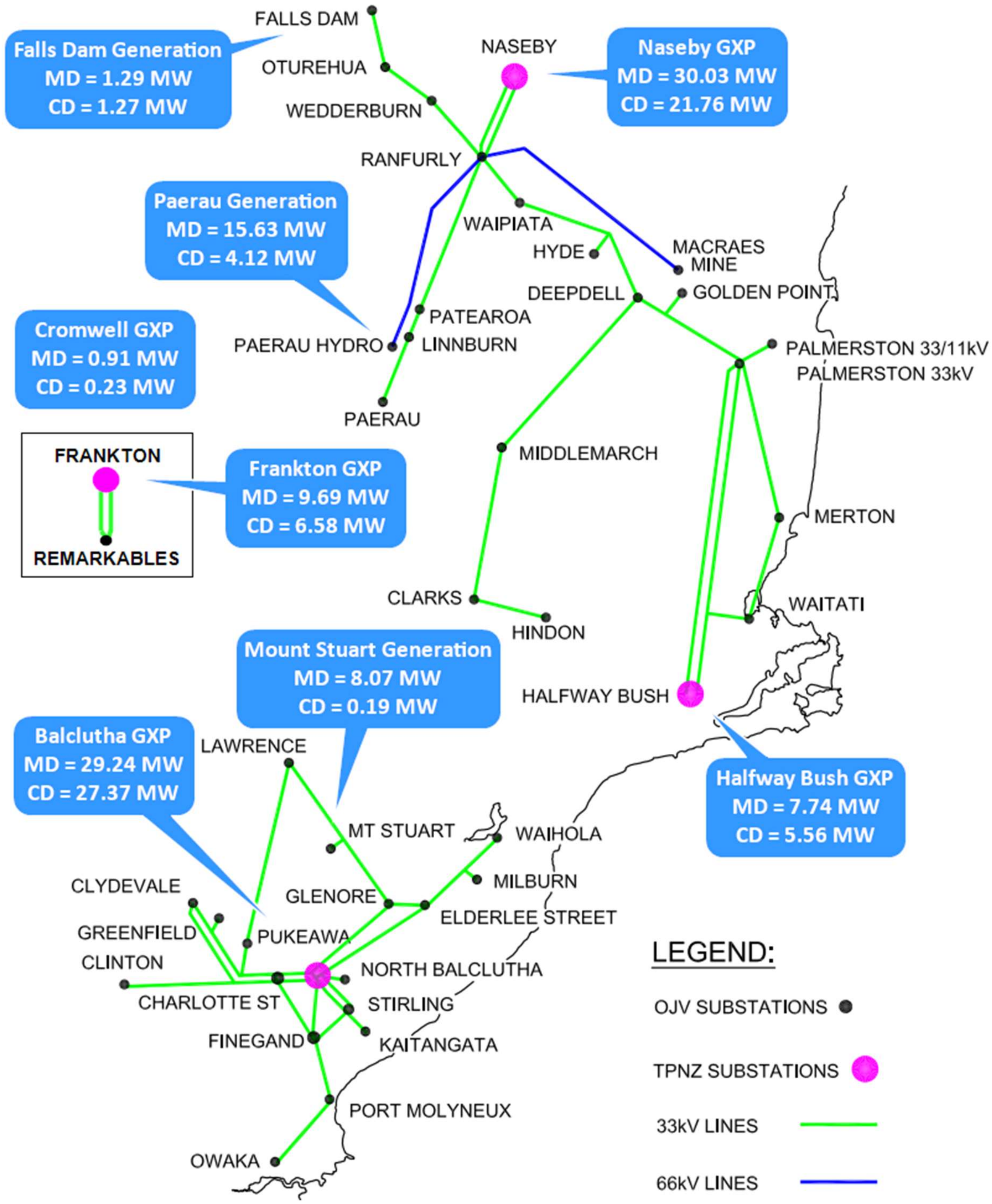
Networks Investment in electricity networks will need to increase significantly to enable electrification and renewable energy. A significant number of large-scale renewable power stations will need to be connected to the transmission grid over the next 30 years. Modelling shows that the country needs 4.8 GW in the next 8 years (Concept Consulting modelling). New core grid interconnections will be required to enable these new connections and electrification. Historically, transmission connections have been in very large, centralised power stations, which has kept the number of required connections low and has enabled greater predictability in the associated core grid upgrades required. As the pace of change accelerates, the future needs of the grid will become more uncertain. Annual investment of about $1 billion in transmission is needed to enable renewable generation and electrification.

Current Demand Profiles

Maximum demand (MD) for individual areas do not occur at the same time. The Lower South Island (LSI) peak occurred at 8:00 a.m. on the 15th of October 2020[9]. The LNL (Frankton) MD of 9.7 MW occurred at 8:00am, 1st July 2021, a different time to both the overall OJV MD and the LSI peak. The OJV coincident demand at the time of the LSI peak was 67.1 MW, with 6.6 MW of that load contributed by LNL. The individual maximum demands are displayed in Figure 46.

[9] The LSI peak demand is calculated each year for the period between 1 September and 31 August.

Figure 46: GXP and Generation Demands



Demand History

Random variations over and above the main growth patterns impacts the accuracy of growth trends. In general, a ten year rolling average will vary substantially between successive years. Longer term trends tend to average out random variations but also obscures recent changes to underlying growth.

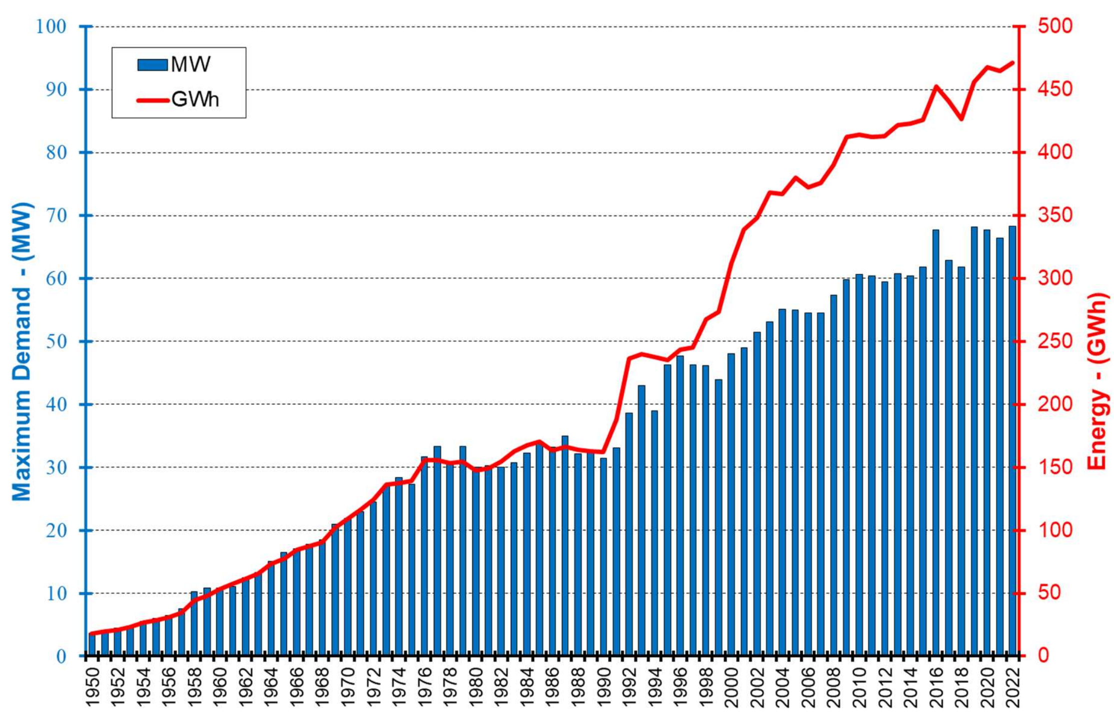
Some causes of variations might be identified with hindsight but these are difficult to predict, for instance a drought initiating irrigation load increases.

Growth patterns over various time periods need to be considered including known events that impact consumption before a reasonable estimate of growth can be determined (to be used for forecasts of future demand and consumption).

Analysis of historic demand and energy usage indicates maximum demand growth has been stabilising in recent years after an increasing trend at the start of the decade, while energy consumption is showing a general rising trend. Figure 47 shows the overall maximum demand from 1950 and highlights the substantial increase in load associated with the Macraes Flat gold mine. LNL (Frankton) load is included in Figure 47 from 2016 onwards.

The data presented is for supply to customers' connection points.

Figure 47: Maximum Demand and Energy Transmitted



Demand Trends

The following sections examine the most significant drivers of the network demand over the next 10 to 15 years in detail.

Each zone substation recorded the maximum demand as listed in Table 51. The figures are analysed and adjusted to compensate for short term load transfers and to produce a more accurate figure of actual maximum demand (per area). When conducting analysis at substation level, allowance must be made for load transfers.

Table 51: Zone Substation Demand

Zone Substation	Maximum Demand (MVA)								
	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15	2013/14
Charlotte Street (Balclutha)	5.2	5.3	5.0	5.2	5.2	5.2	5.5	6.5	6.1
Clarks	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Clinton	2.1	2.1	2.0	2.1	2.0	2.0	1.9	2.1	2.0
Clydevale	3.6	3.7	3.4	3.6	3.7	3.4	3.0	2.9	2.7
Deepdell	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Elderlee Street (Milton)*	4.6	4.5	4.4	4.4	4.4	4.6	4.9	4.6	6.4
Finegand	1.1	1.1	1.1	1.2	1.1	1.1	1.1	1.1	1.1
Glenore	0.7	0.7	0.6	0.8	0.6	0.7	0.6	0.8	0.7
Golden Point**	2.4	2.9	2.7	3.5	2.9	2.9	3.4	3.4	4.2
Greenfield	2.3	2.2	2.2	1.9	1.8	1.8	1.7	1.6	1.7
Hindon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2
Hyde	0.9	0.7	0.7	0.7	0.8	0.8	1.3	1.2	1.2
Kaitangata	1.5	1.4	1.5	1.4	1.3	1.4	1.4	1.4	1.4
Lawrence	1.2	1.3	1.2	1.2	1.2	1.2	1.3	1.2	1.5
Linnburn	0.8	1.0	0.9	0.8	0.9	0.8	0.9	1.0	0
Merton	2.6	2.6	2.5	2.4	2.6	2.4	2.9	2.5	2.4
Middlemarch	0.8	0.8	0.9	0.8	0.8	0.8	0.9	0.8	0.7
Milburn	2.5	2.4	2.7	2.5	2.5	2.3	2.1	2.0	2.4
North Balclutha	2.6	2.7	2.5	2.7	2.8	2.8	2.8	2.9	2.8
Oturehua	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2
Owaka	1.5	1.5	1.5	1.4	1.5	1.4	1.5	1.7	1.5
Paerau	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Paerau Hydro	12.1	12.2	12.3	12.5	12.5	12.5	12.2	12.8	12.8
Palmerston	2.1	2.2	2.2	2.2	2.4	2.3	2.4	2.2	2.2
Patearoa	2.0	1.9	1.8	1.8	1.8	1.5	1.8	1.7	1.7
Port Molyneux	0.7	0.7	0.8	0.7	0.6	0.6	0.6	0.6	0.7
Pukeawa	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Ranfurly 33/11kV	2.2	2.2	2.3	2.0	2.0	2.2	2.1	2.1	2.2
Ranfurly 66/33kV	26.8	23.4	26.5	26.2	28.4	28.7	26.4	30.9	25.3
Remarkables (Frankton)	9.7	8.3	7.4	6.3	4.9	4.4	3.2	2.4	2.2
Stirling	3.8	4.0	4.0	4.2	3.9	4.2	3.9	4.0	3.9
Waihola	1.2	1.3	1.3	1.2	1.2	1.1	1.1	1.1	1.2

Zone Substation	Maximum Demand (MVA)								
	2021/22	2020/21	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15	2013/14
Waipiata	1.4	1.7	1.5	1.4	1.6	1.4	1.4	1.4	1.3
Waitati	1.8	1.9	1.6	1.5	1.6	1.5	1.5	1.7	1.5
Wedderburn	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2

* Load transferred to Milburn 2013

** Load partially transferred to Macraes 2015

The main drivers of growth in recent years have been localised increased irrigation and industrial growth, and in LNL (Frankton) rapid residential development.

A temporary substation was established at Linnburn in 2014, to accommodate the rapid irrigation-based load growth in the Patearoa area until the Patearoa Substation Upgrade is completed in 2025.

Development Triggers (based on growth)

Demand is basically created by individual customers withdrawing (or introducing) energy through their individual connection points. The demand at each connection aggregates "up the network" through LV reticulation to the distribution transformer, then through the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to the power stations. As the load aggregates through the network, load diversity tends to support better load factor and capacity utilisation.

Demand growth is the predominant driver for network development. Growth triggers were identified and corresponding thresholds set to achieve desired service levels (where appropriate). In meeting future demand (while maintaining service levels), the first step is to determine if the projected demand will exceed any of the trigger points for asset location, capacity, reliability, security or voltage. The trigger points for each asset class and typical network solutions are outlined in Table 52.

Table 52: Development Triggers

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within network area but not immediately adjacent to existing infrastructure.	New assets are required to extend the network to the new customer. Additional capacity may also have to be built into the nearest existing network and upstream assets depending on customer size.
Capacity	Load exceeds capacity rating of network assets (or encroaches on spare capacity required to be maintained) or voltage drops below acceptable levels, i.e., below 0.94pu at customer's premises. Proactively identified through network modelling and monitoring load data from meters or MDIs* but may occasionally manifest as overload	Replace assets with greater capacity assets. May utilise greater current ratings or increase voltage level (extension of higher voltage network, use of voltage regulators to correct sagging voltage or introduction of new voltage levels). Alternative options are considered prior to these capital-intensive solutions but generally provide a means to delay investment; may be network based such as adding cooling fans to a zone substation transformer or non-network e.g. controlling peak demand with ripple control.

Development	Trigger Point	Typical Network Solution
	protection operation, temperature alarms or voltage complaints.	
Security and Reliability	Load reaches the threshold for increased security as defined by OJV's security standard. Customers (especially large businesses) may request and be willing to provide a capital contribution for increased security.	Duplicating assets to provide redundancy and continued supply after asset failures. Increase meshing/interconnection to provide alternative supply paths (backups). Additional switching points to increase sectionalising i.e., limit amount of load which cannot have supply reinstated by switching alone after fault occurrence. Automation of switching points for automatic or remote sectionalising or restoration.

*MDI = Maximum Demand Indicator – device that monitors the highest demand on the equipment

OJV will identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points when a trigger point is exceeded. New capacity has an impact on the balance sheet, depreciation and ROI. There is an overall preference for avoiding new capital expenditure and endeavours will be made to meet demand by other, less investment-intensive means. The following potential responses and options are considered:

- Pricing reform (recently completed).
- Demand side management.
- Partnerships for non-traditional solutions.

If the extent of changes is substantive, assets may become underutilised to such an extent that OJV may be unable to fully recover regulated investments. The Commerce Commission has endorsed an asset stranding risk mitigation option for those EDBs subject to price control. This allows OJV to apply for accelerated depreciation recovery (up to 15% reduction in asset lives), subject to the Commerce Commission's approval prior to the next regulatory period.

Future Demand

Future demand forecasts are determined by an understanding of historical trends and then projecting these into the future. Projections are adjusted by factors which are likely to cause demand deviations from current trends.

Population, Demographics and Lifestyle Drivers

Demographics and lifestyle drivers of future demand is provided in the next table and population projections in Figure 48.

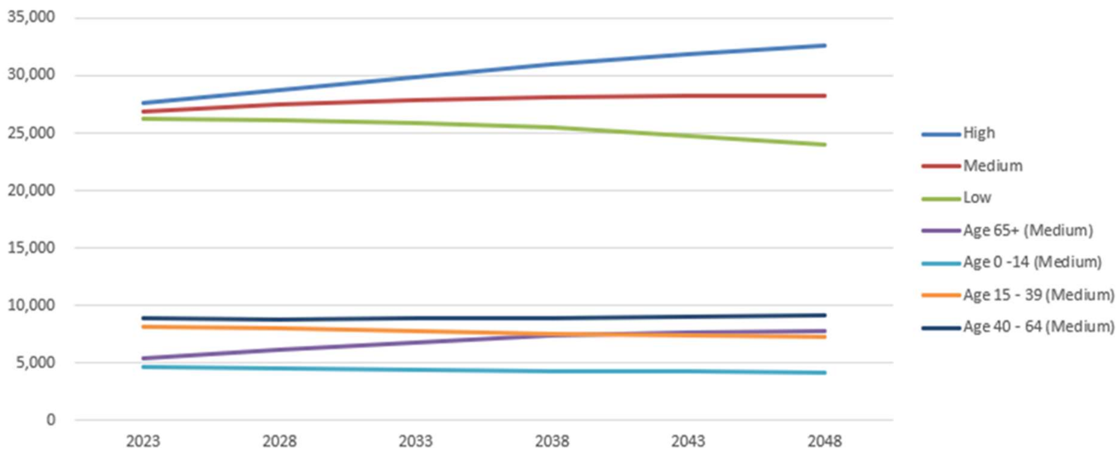
Table 53: Demographics and Lifestyle Drivers

Population Growth and Decline	**Effect:** Accelerated growth in the Frankton area. Population in other areas largely static.
Description: Census data shows no major changes in population in the rural Otago areas serviced by OJV. A small proportion (1.6% in 2023 and projected to be 2.0% by 2033) of the population that falls within OJV's distribution area are in the Queenstown-Lakes District which has a relatively higher population growth rate compared to other districts. The Queenstown-Lakes population has a forecast population growth of 15.6% by 2033, an upper bound of 26.6%, and a	

lower bound of 5.0%. All indicators suggest that this high growth rate is likely to continue due to the high development in the area.	
Housing Density and Utilisation	**Effect:** Overall support of domestic power demand growth from increasing population as described above. Effects of increased housing density is somewhat offset by increasing housing utilisation as more people share heating and other power requirements.
Description: Housing density and utilisation can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand.	
Rural Migration to Urban Areas	**Effect:** Potential increase in urban load.
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas. The "baby boomer" generation is now approaching retirement age, and the convenience of an urban lifestyle will appeal to many. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This factor may create an upward trend in the population of the larger townships in the Otago area, however little evidence of this has been seen in terms of network electrical demand as yet.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months. Consumer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing, they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for OJV over the next ten years.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. However heat pump installation cost is a barrier for many people and some prefer the ambience of other heat sources. Therefore complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period of time. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run.	
Electricity Affordability	**Effect:** Reduction of customer numbers and load.
Description: Line charges in the Otago regions reflect OJV's high cost of transporting energy over large distances to limited numbers of customers. These costs make alternative technologies such as solar and photovoltaic more attractive to customers. While these alternative technologies are not yet competitive with traditional supply, their gradually declining costs may make them more competitive toward the end of the planning period.	

The current population projections for OJV's network area are based on estimates from the 2018 Census data from Statistics New Zealand. Projections for the 65+ age group indicates a significant aging of the population as highlighted in the following figure.

Figure 48: Population Projections



Environmental and Climate Drivers

Drivers of future demand based on changes in the environment and climate is discussed in Table 54.

Table 54: Environment and Climate Drivers

Removal of Coal as Heating	**Effect:** Continuation of existing trends towards electrical space heating
Description: Coal has declined as a heat source in the household market. This will result in an increase in use of alternative sources of heating including heat pumps with resulting growth expected to affect residential areas. Heat pump usage has naturally continued to increase as a convenient and efficient form of heating and the impact on demand has been less than earlier anticipated, therefore existing growth has been assumed to continue.	
Energy Conservation Initiatives	**Effect:** Customers are responding to marketing, strategies and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.
Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating.	
Increasing Average Ambient Temperature	**Effect:** Small increase in maximum demand on inland rural substations.
Description: Increasing average ambient temperature predicted by climate scientists may create increased demand for cooling systems and irrigation. Cooling demand would occur in the warmer months and therefore not coincide with the current peak demand which occurs in the winter months, being dominated by heating requirements. It would take a very large change in ambient temperature for peak consumption to be dominated by cooling in summer months and is expected to simply improve load factor by a small degree. Increased irrigation demand would also occur in the warmer months and is likely to coincide with current peak demands at the distribution feeder and zone substation level where irrigation is already the main driver of demand.	

Wider Range in Weather Variations	Effect: Potential impact on maximum demand, and worsening load factor. Some impact on network reliability.
Description: Climate scientists forecast a potential for increasing frequency and/or intensity of storms, along with wider variations in seasonal weather. Colder periods may increase heating load, adding to current peak demand.	

Economic Drivers

Economic drivers of future demand include major industry growth as well as $NZD variation and commodity cycles. These drivers are presented in the next table.

Table 55: Economic Drivers

Major Industry Continuance or Growth	**Effect:** The most likely scenario is considered that in which existing industries will continue or reduce, and no major new industries will eventuate therefore no change from existing trends forecasted.
Description: Dairy Industry, Tiwai, Major Petrochemical Extraction or Processing etc. The Tiwai aluminium smelter takes supply directly from the transmission grid; but it helps support many businesses and individuals in the OJV area, both directly and indirectly. Approximately 1000 full time equivalent employees and contractors work at the smelter. Concerns about the smelter closure have resurfaced, however as of time of writing it has been confirmed that the smelter will continue to operate until the end of 2024. Loss of this business would have a major impact on the local economy and therefore growth on OJV's network in Invercargill and Bluff. The Great Southern Basin is a potentially viable location for deep water oil drilling. Possible flow on effects if a deposit is developed could create infrastructure and demand at the Bluff port however Dunedin port could be favoured over Bluff. The recent report of OMV's unsuccessful exploration of the Tawhaki 1 well, lowers confidence of the Great Southern Basin potential. Subsequent exploration efforts are unlikely. The likelihood of growth effect on the network is substantially reduced and has therefore been excluded from forecasted growth within the planning horizon.	
$NZD Variation & Commodity Cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.
Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident. The recent coronavirus may result in an economic downturn, and stall recovery. Recent foreign exchange developments have not been favourable to the NZD, resulting in higher import prices for equipment.	

Technology Drivers

Electric and autonomous vehicles, distributed generation, energy efficiency and storage as well as the Internet of Things (IoT) are included in technological drivers of future demand. These are discussed in the following table.

Table 56: Technology Drivers

Electric Vehicles	**Effect:** Some demand growth toward the end of the ten year planning horizon.
Description: Electric vehicles have the potential to have a large impact on network demand if there is sufficient penetration into the transport sector. While it is not considered likely that electric vehicles will be widely used in the next five years, it is forecast that by 2030 10% or more of the light passenger fleet could be electric. OJV intends to use	

strategies such as cost-reflective pricing to encourage electric vehicle owners to charge their vehicles during off-peak hours, thus reducing the impact on peak demand and increasing load factor.

However OJV must allow for the possibility that consumers may not respond well to price signals, causing vehicle charging to occur on-peak. In this scenario modelling shows that the OJV medium voltage network will be able to cope with the increased demand, with minor adjustments to normal configuration. However the lower diversity on the LV network makes it both more likely that voltage issues will occur, and more difficult to predict in advance where those issues will occur.

OJV, through PowerNet, has planned an upgrade of data analysis of ICP smart meters to provide increased visibility of power flow on the network. This data when analysed together with supplementary Maximum Demand Indicators at distribution substations, will better enable OJV to identify vulnerable points on the LV network and proactively upgrade to remove the weakness.

Autonomous Vehicles	**Effect:** Potential for residential customer density to spread. Potential clustering of electric vehicle charging during business hours, and greater loading on lines further from zone substations. Some impact expected toward the end of the ten year planning period.

Description: Autonomous vehicles have the potential to have a large impact on the spread of network demand if there is regulatory acceptance and sufficient penetration into the passenger transport sector.

Autonomous vehicles lower the costs of commuting and may make living further from centres of business more viable for consumers. The economic case for uptake is further weighted by higher housing costs in target destinations.

Adoption and network impact is highly correlated to uptake of electric vehicles, as the technology is often packaged into newer electric vehicles. Housing cost drivers are viewed as less urgent in Southland, compared to other areas of New Zealand. So the impact of this technology on network demand is expected to be less rapid.

Progress will be monitored through the same smart meter data programme described in the Electric Vehicles section above.

Distributed Generation	**Effect:** DG (Distributed Generation) could have significant customer and market benefits. From the distribution network, their impact is expected to be more limited, particularly if effectively managed. Almost all of new generation is from Solar PV, whilst the network peak is historically on winter evenings.

Description: As of December 2022, there are 296 distributed generation connections in OJV. This is approximately 1.9% of the total connected customers. 288/296 (97%) of the DG connections seen so far have been solar installations and this trend is expected to continue for the foreseeable future.

Through our annual customer engagement survey, 38% of customers across all PowerNet managed networks were considering buying and install solar panels in 2022. This is an increase from 28% indicated in the earlier 2018 survey showing customers are increasingly perceiving solar PV as a valuable investment. The main barriers to adoption related to economic reasons where projected payback period was a large influence on the purchase intention. Other considerations that may limit solar uptake are property ownerships and energy cost reduction options such as home insulation and electric vehicles now receiving increasing attention and better returns.

The LV network can be vulnerable to DG installations particularly solar which, without energy storage, depresses the midday trough in demand (or even reverse power flow) whilst leaving the evening peak unaffected. This increases the range of load currents (and therefore voltage drops) under which the LV network must operate. A network tuned to deliver the minimum acceptable voltage in the evening may still exceed the maximum acceptable voltage at midday if customers connect sufficient solar generation without sufficient storage and controls.

The impact of DG installations on the network can be significantly reduced when the inverters employ Volt-VAr compensation so PowerNet has made it a requirement for the majority of connections.

Similarly to electric vehicles, the concentration of effects on the LV network makes the location of future voltage problems difficult to predict. Conducting congestion studies by running multiple penetration levels of DG scenarios on the LV network can also be useful to identify network capacity thresholds and constraints prior to approving new DG connections or requiring controls to be in place so that voltage problems are minimised.

Energy Storage	**Effect:** Not expected to have a significant presence within the ten year planning horizon and therefore negligible effect on network demand.

Description: As mentioned above, almost all of new DG is from solar PV, while OJV network peak is historically on winter evenings. Coupling solar PV generation with energy storage could change this dynamic, but at present rates the storage capacity provided is immaterial. Storage gives customers some control over their demand without impacting their consumption and could make it feasible for customers to go "off-grid" with a sufficiently sized generation source. However, there is significant uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able

to promote/utilise/market storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals. Under the status quo this technology is not economic except in exceptional circumstances, and it is not expected that there will be major developments in this area for the next five years. If any such developments occur in the second half of the planning period, it is expected that they will take several years to have an impact at the network level, during which time OJV can respond in a focused manner. Any impact these devices have is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets.	
Energy Efficiency	**Effect**: Negative growth driver accounted a part of the energy conservation initiatives.
Description: Improving energy efficiency has been a government strategy for several years (energy conservation initiatives). It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.	
On-line shopping	**Effect:** Likely to negatively affect the business sector in OJV's network area however the overall effect on demand is expected to be relatively insignificant.
Description: Shopping online continues to become more and more popular, with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within OJV's network area. However there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in OJV's area.	
Internet of Things	**Effect:** This technology is becoming more widespread with a significant number of applications being developed, however there are few products that are targeted at reducing demand therefore not affected demand forecasts. In the case that it does eventuate in the next ten years the uptake of this technology is likely to be gradual and so network plans would be able to react sufficiently quickly.
Description: The internet of things refers to the interconnection of the internet and many electronic enabled devices. In particular smart appliances may enable centrally controlled management of a dwellings or business's consumption so that maximum demand may be minimised by staggering load to make the most of potential load diversity. This could enable customers to reduce line charges in line with a reduced network capacity requirement for their supply.	

Demand Forecasts

The overall impact of the future demand drivers is a 1.2% per annum maximum demand growth rate. Growth per substation is the most appropriate level for identifying constraints on the network.

The projected substation demands indicate the expected growth forecast. This is the most likely outlook and these projections are the basis for OJV's network development planning. OJV also carries out an internal prudent growth forecast with appropriate contingency planning. Actual future demands may deviate significantly from the growth projections. Potential causes could include lower peak demand due to changing consumer habits. Increased energy efficiency in homes is likely to be balanced by increased demand for electrical heating. Forecasts are updated annually to ensure that plans can rapidly respond to changes from previous assumptions.

With declining growth rates, project schedules (to address capacity constraints) are postponed to minimise over-investment risks. OJV endeavours to realise growth opportunities as they arise, which means developing the network to alleviate constraints as required within the parameters of acceptable risk. The risk of stranding of new assets is managed through capacity guarantee contracts with new customers (where appropriate). Risk is also minimised through avoidance of investment until necessary yet still maintaining the desired service levels. Higher growth rates are a possibility and present a risk of missed opportunity for growth for both OJV and OJV's customers.

It is expected that growth affecting the entire network will be determined with sufficient timing to allow for resource adjustments. Large scale developments are likely to be funded by external investors through capital contributions. In general, OJV has the ability to quickly respond to unforeseen large scale developments that occur once-off. Limits to this capability might be negotiated around timing of project delivery. While all efforts are made to inform customers of potential lead times for providing additional network capacity, requests for supply are often made late in customers' planning processes due to commercial sensitivities.

Network Constraints

Balclutha GXP

The Balclutha GXP has a firm capacity of 30 MVA and with the historical GXP maximum demand at 29.2 MW an upgrade will be required in the medium term. In the interim the two transformer's post-contingency rating of 37/39 MVA each (summer/winter) will provide for peak demands which occur in summer due to seasonal agricultural processes.

A new GXP in the Milton area is a contingency project that would be activated should significant industrial load materialise in that vicinity. The new GXP would transfer approximately 7 MVA of demand from Balclutha, allowing the GXP transformers' upgrade to be deferred.

The Balclutha subtransmission network has adequate capacity for forecast load growth over the ten year planning horizon, but step increases e.g. new or expanded industrial or agricultural processing facilities, or electrification of process heat would necessitate network upgrades.

Naseby GXP

The Naseby GXP has a firm capacity of 40 MVA and with the historical GXP maximum demand at 30.0 MW there is sufficient capacity to provide for load growth over the ten year planning period.

The predominant load is a mine, and future load growth is constrained by the subtransmission network, specifically the N-1 capacity of the two 33kV lines from the Naseby GXP to Ranfurly substation. Should sufficient growth occur the constraint can be removed by upgrading the Naseby to Ranfurly lines to 66kV, or by increasing the 33kV lines' thermal rating. Relevant equipment at Naseby GXP is already 66kV capable.

Other parts of the Naseby subtransmission network has adequate capacity for forecast load growth over the ten year planning horizon.

Halfway Bush GXP

The Halfway Bush GXP's firm capacity is 120/100 MVA (T3/T5) and load is dominated by Aurora Energy. OJV's maximum demand is 7.7 MW. The total peak load is close to the n-1 capacity available but is supplemented by a significant amount of embedded hydro and wind generation, consequently Transpower are not currently planning a capacity upgrade.

Significant load growth in the area is not forecast, but if it arises then low voltage at Waitati could occur when one Halfway Bush to Palmerston 33kV line is out of service. This issue will be resolved in the first instance by the new Quarry Road substation in 2027, which will connect to the subtransmission network at a point closer to Halfway Bush than Merton (which Quarry Road replaces) does currently. This will reduce the subtransmission volt drop. Secondly Blueskin Bay substation, which will replace Waitati substation in 2029, will also connect closer to Halfway Bush. If demand increases significantly then one of these projects can be brought forward to mitigate against excessive voltage loss in the subtransmission lines.

Frankton GXP

The Frankton GXP has a firm capacity of 66/85 MVA (T2/T4) and as for Halfway Bush, load is dominated by Aurora Energy. OJV's maximum demand is 9.7 MW, and total demand was forecast to exceed the n-1 supply capacity of the transformers and incoming 110kV circuits in winter 2022. A new special protection scheme at Frankton allows pre-contingency load to reach 120 MW, and PowerNet is working with Transpower and Aurora to develop medium to long-term options to resolve the Frankton capacity issues.

Zone Substations

Table 57 displays the projected maximum demand for zone substations at the end of the ten year planning horizon and the expected provisions for future growth. The assumption is that unforeseen changes in growth rates or step changes due to connection or loss of large customers will not occur.

Table 57: Substation Demand Growth Rates

Substation	MD (MVA) 2021/22	MD (MVA) 2032/33	Provision for Growth
Charlotte Street (Balclutha)	5.2	5.4	Charlotte Street has a capacity of 10MVA and a firm rating of 5MVA. It supplies the part of Balclutha that is on the south side of Clutha River, including the CBD, and the surrounding rural areas. The firm rating is being exceeded occasionally, if a capacity constraint arises it can be managed by transferring load to North Balclutha substation.
Clarks	0.3	0.3	Demand growth in the Clarks area is historically flat. The rural consumers are served by a single 0.5MVA transformer supplying 22kV SWER feeders.
Clinton	2.1	2.2	Clinton substation has a capacity of 2.5MVA available from its single transformer, which is sufficient for a prudent growth forecast beyond the ten year planning horizon.

Substation	MD (MVA) 2021/22	MD (MVA) 2032/33	Provision for Growth
Clydevale	3.6	4.9	Clydevale substation has a capacity of 5MVA available from its single transformer. Increased irrigation on dairy farms and new water schemes are likely to drive increased demand, which is currently forecast to exceed the transformer's capacity just beyond the ten year planning horizon. A transformer capacity upgrade will take place to ensure that demand growth can be met. A second transformer will be required to bring security to the required AA level once demand reaches the 5MVA trigger level.
Deepdell	0.1	0.1	Demand growth in the Deepdell area is historically flat. The rural consumers are served by a single 0.75MVA transformer.
Elderlee Street (Milton)	4.6	5.7	Elderlee Street has a capacity of 10MVA and a firm rating of 5MVA. There have been indications of residential and industrial growth in the Milton area in recent years and the substation is planned for replacement with increased capacity at a new site in Tower Road. An additional 0.7MVA of load will be transferred to Tower Road from Glenore substation which is to be decommissioned.
Finegand	7.6	7.6	Finegand substation's 11kV bus has a capacity of 2.5MVA available from a single transformer, and an industrial customer is bulk supplied at 33kV. The Finegand area that is supplied at 11kV has historically flat demand.
Glenore	0.7	0.0	Demand growth in the Glenore area is historically flat. The rural consumers are served by a single 1.5MVA transformer. The substation is to be decommissioned and its load transferred to Tower Road substation (see 'Elderlee Street' above).
Golden Point	2.4	2.4	Golden Point supplies a mining customer and in recent years the substation has been utilised as a standby supply only. The single transformer is rated at 5MVA.
Greenfield	2.3	3.4	Greenfield substation provides bulk 33kV supply to an industrial customer. The 5.7MVA voltage regulator has capacity for expected load growth beyond the ten year planning horizon.
Hindon	0.2	0.2	Demand growth in the Hindon area is historically flat. The rural consumers are predominantly served by a single 0.55MVA transformer supplying 22kV SWER feeders and a single 0.1MVA transformer serves three-phase consumers.
Hyde	0.9	0.9	Demand in the Hyde area is historically flat. Hyde's single 2.5MVA transformer supplies the rural community but the predominant load is pumps that serve a mine.
Kaitangata	1.5	1.6	Kaitangata substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area. Some very modest load growth from new housing in the township has occurred in recent years.
Lawrence	1.2	1.2	Lawrence substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area. Load growth is historically flat.
Linnburn	0.8	0.0	Linnburn is a temporary substation commissioned in 2014 in response to rapid irrigation growth. It has a single 1MVA transformer. The site will be decommissioned in 2025 and its load transferred to Patearoa substation.

Substation	MD (MVA) 2021/22	MD (MVA) 2032/33	Provision for Growth
Merton	2.6	2.7	Merton has a capacity of 5MVA and a firm rating of 2.5MVA. If a capacity constraint arises it can be managed by transferring load to neighbouring substations. Merton is planned for replacement with increased capacity at a new site in Quarry Road, closer to the load centre which is Waikouaiti township. Quarry Road is to be commissioned in 2027.
Middlemarch	0.8	0.9	Middlemarch substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area. Some modest load growth from new irrigation has occurred in recent years.
Milburn	2.5	3.4	Milburn has a capacity of 5MVA provided by one transformer with a standby transformer rated at 2.5MVA. The substation supplies industrial customers and the rural community. Some industrial load growth within the substation's existing capacity is expected during the ten year planning period.
North Balclutha	2.6	2.7	North Balclutha substation has a capacity of 5MVA available from its single transformer. It supplies the part of Balclutha that is on the north side of Clutha River, Stirling township and the surrounding rural areas. Load growth is historically flat.
Oturehua	0.2	0.2	Demand growth in the Oturehua area is historically flat. The rural consumers are served by a single 0.75MVA transformer.
Owaka	1.5	1.5	Owaka substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area. Load growth is historically flat.
Paerau	0.2	0.2	Demand growth in the Paerau area is historically flat. The rural consumers are served by a single 1MVA transformer.
Paerau Powerhouse	12.1	12.1	Paerau Powerhouse serves a hydro generation scheme and has a capacity of 30MVA and a firm rating of 15MVA.
Palmerston	2.1	2.2	Palmerston substation has a capacity of 5MVA and a firm rating of 2.5MVA. The substation supplies the township and its surrounding rural area. Load growth is historically flat.
Patearoa	2.0	3.9	Patearoa substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area where irrigation is driving load growth. The transformer will be upgraded to 7.5MVA in 2025 to accommodate forecast load growth, a load transfer from Ranfurly and the load currently served by Linnburn, which is to be decommissioned (see 'Linnburn' above and 'Ranfurly 33/11kV' below).
Port Molyneux	0.7	0.8	Port Molyneux substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the Kaka Point township and its surrounding rural area. Load growth is historically flat.
Pukeawa	0.5	0.7	Pukeawa substation has a capacity of 0.75MVA available from its single transformer. Some modest irrigation growth has occurred on dairy farms, growth is currently forecast to be within the transformer's capacity within the ten year planning horizon.
Ranfurly 33/11kV	2.2	2.1	Ranfurly has a capacity of 2.5MVA provided by one transformer with a standby transformer rated at 2.5MVA. The substation supplies the townships of Ranfurly and Naseby as well as the surrounding rural community. Some irrigation load growth is expected during the ten year planning period, which will be offset by a planned load transfer to Patearoa substation after its 2025 transformer upgrade.

Substation	MD (MVA) 2021/22	MD (MVA) 2032/33	Provision for Growth
Ranfurly 66/33kV	26.8	27.0	The Ranfurly 66kV bus supplies a hydro generation scheme and a mining customer, it has a capacity of 50MVA and a firm rating of 25MVA. The present growth constraint is due to the N-1 capacity of the two 33kV lines from Naseby GXP to Ranfurly, which can be alleviated by upgrading the lines to 66kV. Relevant equipment at Naseby GXP is already 66kV capable should new demand appear.
Remarkables (Frankton)	9.7	11.5	Remarkables substation in Lakeland Network has a capacity of 46MVA and a firm rating of 23MVA. Remarkables serves mainly residential customers in Frankton and surrounding areas and the rapid rate of residential development being experienced is expected to continue. The maximum demand at Remarkables will be mitigated by a new zone substation serving the Southern part of Lakeland Network, to be completed in 2031.
Stirling	3.8	3.8	Stirling substation has a capacity of 5MVA available from its single transformer. The substation supplies a dairy processing plant and is a standby supply for the surrounding distribution network, which is normally supplied by North Balclutha substation. The peak demand has decreased slightly in recent years due to dairy production efficiencies. Future growth is not presently indicated.
Waihola	1.2	1.4	Waihola substation has a capacity of 1.5MVA available from its single transformer. New residential development has driven modest load growth recently and the trend is forecast to continue. Demand is expected to exceed the transformer's capacity just beyond the ten year planning horizon. A transformer capacity upgrade will take place to ensure that demand growth can be met.
Waipiata	1.4	1.5	Waipiata substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the township and its surrounding rural area where irrigation has driven load growth in recent years. The growth rate is expected to flatten over the present ten year planning horizon.
Waitati	1.8	2.1	Waitati substation has a capacity of 2.5MVA available from its single transformer. The substation supplies the townships of Waitati and Warrington and the surrounding rural area. New residential development has driven modest load growth recently and the trend is forecast to continue. The substation is planned for replacement with increased capacity at a new site in 2029.
Wedderburn	0.2	0.2	Demand growth in the Wedderburn area is historically flat. The rural consumers are served by a single 1MVA transformer.

Projected annual maximum demands incorporating growth provisions is presented in Table 58. Sites with high loads will be closely monitored to determine if capacity will be exceeded in the short term. Annual preparation of data will highlight sites with capacity constraints and the planned works will be adapted for each situation. This would entail that some capacity upgrades be delayed or brought forward.

Table 58: Substation Maximum Demand (incorporating growth)

Substation	'23/24	'24/25	'25/26	'26/27	'27/28	'28/29	'29/30	'30/31	'31/32	'32/33
Charlotte Street (Balclutha)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.4	5.4	5.4
Clarks	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Clinton	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Clydevale	3.7	3.9	4.0	4.1	4.2	4.4	4.5	4.6	4.7	4.9
Deepdell	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Elderlee Street (Milton)	4.7	4.7	4.7	4.8	4.8	4.9	4.9	5.5	5.6	5.7
Finegand	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Glenore	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0	0.0
Golden Point	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Greenfield	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.2	3.3	3.4
Hindon	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Hyde	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Kaitangata	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6
Lawrence	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Linnburn	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Merton	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7
Middlemarch	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
Milburn	2.6	2.7	2.8	2.9	3.0	3.0	3.1	3.2	3.3	3.4
North Balclutha	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Oturehua	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Owaka	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Paerau	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Paerau Powerhouse	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
Palmerston	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Patearoa	2.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.9
Port Molyneux	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
Pukeawa	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Ranfurly 33/11kV	2.2	2.3	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1
Ranfurly 66/33kV	26.8	26.9	26.9	26.9	26.9	26.9	27.0	27.0	27.0	27.0
Remarkables (Frankton)	10.4	11.2	12.0	12.7	13.5	14.3	15.0	15.8	10.8	11.5
Stirling	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Waihola	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4
Waipiata	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Waitati	1.8	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.1	2.1
Wedderburn	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

OJV also manages other general constraints on its network as described in Table 59.

Table 59: Network Constraints and Intended Remedy

Constraint	Description	Management Approach
Distribution Voltage Drop	The voltage drop at the end of some distribution lines fall below OJV triggers.	The feeder will be upgraded to improve supply voltage. Regulators will be installed on the Patearoa feeders as and when required by the expected load growth. Where voltages are only marginally below OJV triggers and no load growth is expected, demand will be monitored and action taken if the situation worsens.
Interconnected Distribution Feeders	Many distribution lines in rural areas are unable to supply load in backup scenarios due to excessive voltage drop.	Interconnected feeder conductors are analysed in backup scenarios and opportunities to reinforce them are taken if economic. Other options are also utilised e.g. mobile substation deployment, temporary generation or temporary voltage regulator.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored and transformers will be upsized or supplemented with additional units as appropriate. MDIs will be upgraded in the medium term to provide improved data for transformer loading and LV network analysis. Underutilised transformers may be relocated before purchasing new.
Low Voltage Quality of Supply	In some growth areas the LV lines are inadequate to supply the new loads.	Upgrade LV lines in towns as required and consider the size and location of transformers.
Uneconomic Lines	There are many examples of single customers at the ends of feeders with 1-2 km of dedicated line required to support them. Much of this line was built during government-funded rapid expansion of the 1960's and is now approaching end of life. Cost of renewal is disproportionate to benefit.	Each instance of a potentially uneconomic line renewal will be considered on a case-by-case basis. A RAPS (Remote Area Power Supply) will be utilised if more economic.

Distributed Generation and Demand Management

Distributed Generation (DG) influence on maximum demand is negligible due to the estimated low connection density of DG. The probability exists that only a small percentage of the capacity will be available during winter peaks.

Load Management is used when substation equipment is nearing overload as well as with load transfers for maintenance purposes. The assumption is that load management have a minimal influence on projected demand, although historical demand records will include these effects.

Service Level Changes

The general approach of monitoring network demand, and initiating projects when standardised development triggers are reached, serves to maintain existing service levels. Where a change in service level is desirable, this may be undertaken either directly (e.g. targeted seismic remediation program to improve safety and resilience under earthquake conditions), or indirectly through the adjustment of the thresholds used for the triggers (e.g. lowering the minimum number of downstream customers required to justify a dual transformer substation). These decisions tend to be strategic in nature and go beyond the general approach of monitoring network demand and initiating projects when standardised development triggers are reached.

These projects may be triggered by a complex interaction of many factors or driven (or required) by external influences. Examples are the shifting perceptions around staff/personnel safety or acceptable levels of risk, and these will create drivers for network development projects which are not a requirement arising from demand growth.

Development Programme

Development projects underway or planned for the next 12 months, the following four years and those that are considered for the remainder of the planning period are presented in the following tables.

Table 60: Non-routine Development Projects (next 12 months)

Project Description	2023/24 CAPEX Cost
Customer Connection Projects: This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements. Scope and timing of works are adjusted to customers' works plans as communicated to OJV. Expenditure and timing may differ from that published as customer developments progress.	$5,020,143
System Growth Projects: This budget provides for extensions or enhancements to the network to meet growth in demand. It includes projects in Lakeland Network where load growth, predominantly from residential developments, is expected to continue.	$693,194
Asset Relocation Projects: This budget captures costs for general minor relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year. The 2023/24 budget includes the relocation of the assets due to the Milton Main Street Undergrounding project and the Balclutha Community Hub development. These asset relocations are funded by the customer.	$1,838,737
Quality of Supply Projects: The 2023/24 budget includes completion of the Finegand 33kV smart network automation project, supply reliability focused Network Improvement projects, a mobile substation site at Patearoa and in Lakeland Network a new MV link cable and RMU SCADA enhancements.	$1,050,769

On the LV network, operation beyond capacity typically manifests as low voltage experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11 kV extension if required. However in most cases replacing LV wires or cables with larger conductors will be a more economic option to maintain acceptable voltage for all customers. The minimum standard conductor size which provides the existing and spare capacity for expected growth will be used.	
Reliability, Safety and Environment: This budget in 2023/24 includes NER installation work at Stirling and Milburn, an arc-flash upgrade at Stirling, distribution earth refurbishment and procurement of critical spares.	$881,023

Table 61: Non-routine Development Projects (next four years)

Project Description	CAPEX Cost & Timing
Customer Connections: This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements. Connections activity is adjusted in response to known customer initiated works. Capital expenditure allows OJV to provide the required supporting electrical infrastructure. Scope and timing of works are adjusted to customers' works plans as communicated to OJV. Expenditure and timing may differ from that published as customer developments progress. Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate. However, customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated MV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.	$5,020,143 '23/24 $5,660,632 '24/25 $5,084,034 '25/26 $6,195,196 '26/27 $5,972,383- $6,371,647 p.a. '27/28 to '32/33
Finegand 33 kV Smart Network Automation: Finegand zone substation is a junction point for three incoming 33 kV lines that supply 1,658 customers at Kaka Point, Owaka and Finegand, including the Silver Fern Farms plant at Finegand. The loads are divided across the three incoming supply lines. Currently a fault on an incoming line can be isolated and supply restored using manually operated switches, which requires a faults responder to travel to Finegand substation and operate the switches as directed by System Control. The time taken to travel to site and complete the switching has significant SAIDI and SAIFI impact. A closed 33 kV ring protection scheme will allow supply to be maintained for an incoming line fault. Additionally twelve 33 kV structure poles need replacement and the bus and air break switches are at the end of their serviceable life. Employing ground mounted switchgear is the most economic method to replace these assets. Project design and procurement has been completed; construction will be carried out in 2023/24.	$934,780 '23/24
Substation Arc-Flash Upgrades: Arc flash hazards on indoor high voltage switchboards present a risk of harm to personnel inside substation buildings, especially during operation of the switchgear. Available options include:	$92,200 '23/24

• Additional Personal Protective Equipment (PPE) requirements • Operational controls • Protection improvements including arc-flash detection retrofit • Panel reinforcement to contain arc-flash An engineering solution is preferable to an administrative or PPE solution according to the Hierarchy of Hazard Control. The most appropriate engineering solution will be determined prior to installation. The Stirling 11kV switchboard is to be fitted with arc-flash protection. Project design and procurement has been completed; construction will be carried out in 2023/24. Concurrently an NER will be installed at Stirling, refer to 'Substation NERs and 33kV Transformer Circuit Breakers' below.	
Substation NERs and 33kV Transformer Circuit Breakers: As part of compliance with the EEA Guide to Power System Earthing Practice 2009, Neutral Earthing Resistors (NERs) are being installed where necessary on zone substations to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they significantly reduce the earth potential rise appearing on and around network equipment when an earth fault occurs. The EEA Guide sets a higher standard for distribution earthing than was previously applicable. OtagoNet considers that the cost of building/upgrading individual earth sites in compliance with the Guide can be significantly reduced by the relatively low-cost installation of an NER at the upstream substation. Prior to the commencement of this project, two out of seven 5MVA transformers did not have 33kV circuit breakers for transformer protection and relied on 33 kV fuses only. None of the 15 smaller 2.5 MVA transformers had 33kV circuit breakers. Single transformers may be damaged by slow fuse clearing times with little protection for earth faults and dual transformer sites may be vulnerable to additional damage from back feeding into a transformer fault. The installation of an NER reduces the fault current of 11 kV winding faults, thus reducing the level of protection provided by 33 kV transformer fuses. A 33 kV CB offers greater sensitivity to 11 kV winding faults particularly when used with a transformer differential protection scheme. Available options include: • Do nothing and: 1. Accept the higher overall cost of building distribution earths compliant with the EEA Guide. 2. Accept increased transformer damage due to slower fuse protection in the event of a fault. • Install Petersen Coils and carry out the necessary network upgrades to allow sustained operation with phase-ground voltage at phase-phase levels. • Retain fuses, install NER, and accept increased damage to the transformer and possibly nearby equipment in the event of an 11 kV winding fault. • Install NERs and 33kV transformer circuit breakers. • No non-asset solutions. Installing circuit breakers protects the transformer whilst permitting installation of an NER and is considered to provide the best cost-benefit ratio. Project design and procurement has been completed for an NER installation at Stirling, construction will be carried out in 2023/24 concurrently with and arc-flash upgrade, refer to 'Substation Arc-Flash Upgrades' above.	$108,427 '23/24 $166,979 '24/25 $494,668 '25/26

The Milburn substation NER project's design and procurement will commence in 2024/25 and construction will be carried out in 2025/26. An NER is planned for Ranfurly 33/11 kV substation in 2025/26, and other zone substation NER installations are planned in conjunction with other upgrades e.g. switchgear replacement.	
Milton Area Capacity Upgrade: There is potential for significant industrial expansion which would require significant additional capacity in the Milton area. The additional load could exceed the current capacity of the Balclutha Grid Exit Point (GXP) and the 33 kV lines to Milton. Transpower's 110 kV lines that supply Balclutha GXP also have capacity limitations whereas there are two 220 kV lines passing through the area with additional capacity available. A review of the feasible options had indicated a requirement for a new GXP near Milton supplied from the 220 kV grid. Additionally a combination of new subtransmission lines and existing line and substation upgrades would be necessary to supply the industrial sites. Available options include: • Upgrade the Balclutha GXP's capacity, reinforce the 33kV supply to Milton and accept capacity constraints for grid contingency events. • Develop a new GXP connected to one 220 kV line near Milton dedicated to supplying the new industrial loads, with N security for grid contingency events. • Develop a new GXP connected to both 220 kV lines near Milton supplying the new industrial loads and the existing local network load. • Do nothing and accept that the existing capacity constraints will prevent the industrial developments from proceeding and limit future growth. • No non-asset solutions. A new GXP connected to both 220 kV lines near Milton provides both the capacity required and acceptable security. As the future of industrial load demand growth is currently unknown, the new GXP and subtransmission upgrades are contingent on confirmed future demand. However an industrial customer or customers may require additional capacity in a relatively short time frame compared to the time required to purchase land, gain consents, plan and construct a new Transpower GXP. OJV has decided it would be prudent to purchase and designate land for a future GXP in the Milton area. A site suitable for a future GXP will be purchased and designated in 2027/28.	$71,944 '23/24 $214,075 '27/28
Patearoa Substation Upgrade: Load growth is occurring in the region due to spray irrigation. The Patearoa zone substation transformer is at the end of its nominal life. Two nearby feeders may develop voltage issues arising from load growth that could be solved by tie point shifts if sufficient capacity were available at Patearoa. An initial review indicated a requirement for a new zone substation, and a temporary 1MVA substation was erected at Linnburn in 2014 to relieve the load on Patearoa. Subsequent analysis has shown that the extra load can be supported more economically from an upgraded Patearoa zone substation, rather than establishing a new, permanent substation. Available options to increase zone substation capacity in the region include: • Develop a new zone substation at or near Puketoi off the 66 or 33kV lines. • Upgrade Patearoa substation. • No non-asset solutions available. The most economic option is to upgrade Patearoa substation capacity. Linnburn is located on leased land and the lease expires in 2025. Current growth projections indicate that the existing substation's capacity may be sufficient for several years, but the disestablishment	$813,036 '24/25 $993,711 '25/26

of Linnburn and the additional load from tie point shifts necessitate higher capacity at Patearoa. Consequently the substation upgrade is planned for completion in 2025/26. Condition monitoring of the substation transformer indicates continued reliable operation.	
Puketoi Area Regulator & Line Upgrade: Load growth in the region due to spray irrigation will cause voltage issues on the 11kV feeder when Linnburn temporary zone substation is disestablished in 2025 (refer to 'Patearoa Substation Upgrade' above). Available options include: • Field regulators, or • Reconductoring, or • 22 kV conversion. • No non-asset solutions available. The most economic option is to install a field regulator and reconductor part of the feeder in 2024/25 prior to the Linnburn temporary zone substation being disestablished.	$520,346 '24/25
Maniototo Road-Lower Gimmerburn 11kV Line: Load growth is occurring in the Lower Gimmerburn area due to irrigation. The Lower Gimmerburn 11kV feeder, supplied from Ranfurly zone substation, will develop voltage issues arising from load growth that could be solved by a tie point shift if sufficient capacity were available at Patearoa substation, and the gap on Maniototo Road between feeders was bridged. Patearoa substation's capacity will be upgraded in 2024/25 (refer to 'Patearoa Substation Upgrade' above). Extending the feeder from Patearoa and establishing a new open tie point will relieve the Lower Gimmerburn feeder of potential voltage issues in the medium to long term. The feeder will be extended along Maniototo Road in 2025/26.	$192,033 '25/26
Earth Upgrades: Ineffective earthing may create, or fail to control, hazardous voltage that may occur on and around network equipment affecting safety for the public and for staff. Ineffective earthing may prevent protection systems from operating correctly which may affect safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades. The analysis to determine what upgrade options are appropriate can be quite complex but essentially it looks to find the best trade-off between cost and risk reduction. For sites where risk of potential exposure to EPR is high, additional measures such as insulating barriers are necessary to ensure public safety. Routine testing is completed five yearly. This project budget has been increased to cover remediation of non-compliant / un-maintainable sites discovered in the most recent earth inspection / testing round. A number of distribution earths at SWER transformer sites have joins between the transformer and the first earth electrode whereas the applicable EEA Guide specifies an unbroken connection. The affected sites will be upgraded over a period of seven years, to be completed in 2028/29.	$603,226 p.a. '23/24 to '25/26 $575,071 '26/27 $396,656 p.a. '27/28 to '29/30 $223,154 p.a. '30/31 onward
General LNL Network Growth: Continued growth in the Frankton area results in the need to expand and reinforce the distribution network.	$142,472 p.a. '25/26 onward
QLDC Arterial (CBD): This underground cable project facilitates a distribution network extension into the Queenstown CDB. The work will be carried out concurrently with roadway civil works. Available options include: • Install new cable concurrently with civil works to meet future expected customer demand. • Defer the network extension provision and carry it out independently of road works, at higher cost. • Do nothing and accept that future electricity demand will be met by a competitor.	$35,293 p.a. '23/24 to '24/25

Extending the network fits with OJV's strategic objective to facilitate network growth in order to meet customer demand. Works commenced in 2022/23 and completion is planned for 2024/25.	
Kawarau South Bank Cable & Southern Corridor: This project provides a distribution network extension to supply growth and improve supply security to residential developments south of the Kawarau Falls Bridge. Available options include: • Extend the network to meet customer demand and improve supply security. • Do nothing and accept that electricity demand will be met by a competitor. Extending the network fits with OJV's strategic objective to facilitate network growth in order to meet customer demand. The project commences in 2023/24 and completion is planned for 2026/27.	$136,548 p.a. '23/24 to '26/27
Frankton Road 22kV Extension: This project provides a distribution network extension to supply network growth towards Frankton Road. Available options include: • Extend the network to meet customer demand and improve supply security. • Do nothing and accept that electricity demand will be met by a competitor. Extending the network fits with OJV's strategic objective to facilitate network growth in order to meet customer demand. The project commences in 2023/24 and completion is planned for 2026/27.	$443,654 '23/24 $399,533 p.a. '25/26 to '26/27
Northlake to Clearview Link Cable: This project provides a distribution network link to improve supply security to residential developments in Wanaka. Available options include: • Install the link cable to improve supply security. • Do nothing and accept reduced reliability and limited maintenance options. Installing the link cable fits with OJV's strategic objective to provide its customers with above average levels of service.	$142,237 '25/26
New Zone Substation Land: A new zone substation will be required in the long term to service rapid growth in the Wakitipu Basin area (refer to 'Southern Corridor Zone Substation' below). OJV intends to secure a site while land in a suitable location is available.	$538,067 '25/26
RMU SCADA & Communications: This budget is to allow implementation of SCADA and supporting communications infrastructure for ring main units in the Lakeland Network.	$28,812 p.a. '26/27 ongoing
Network Chargeable Capital: This budget captures costs for relocation works when requested by authorities or customers such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year. Undergrounding of assets for the new Balclutha Community Hub is planned for 2023/24.	$313,583 '23/24 $35,929 p.a. '24/25 onward
Milton Main Street Undergrounding: Undergrounding of overhead lines and relocation of distribution transformers for the Clutha District Council's Milton Main Street upgrade is planned for 2023/24.	$1,525,154 '23/24
Supply Quality Upgrades: On the LV network, operation beyond capacity typically manifests as low voltage experienced by customers during periods of peak loading. This may occasionally require a	$12,263 p.a. ongoing

new transformer site with associated MV extension if required. However in most cases replacing LV cables with larger cables will be a more economic option to maintain acceptable voltage for all customers. The minimum standard cable size which provides the existing and spare capacity for expected growth will be used. An alternative to network upgrade is demand side management, however cost incentives to reduce demand are proving ineffective due to the retailers repackaging of line charges into their billing. Costs budgeted represent a long term average with actual spend varying around this average from year to year.	
Network Improvement Projects: This budget is to allow implementation of additional remote controllable switching points and automation technologies.	$182,027 p.a. '24/25 & '25/26 $137,784 p.a. '26/27 to '30/31 $143,836 p.a. '31/32 onward
Easements: A budgeted is allowed for easement costs that are not captured in other projects' budgets.	$5,756 p.a. ongoing
Mobile Substation Site Made Ready: This project will provide connection points for the mobile substation at single transformer substations. The aim is to have each substation suitably arranged to allow the mobile substation to be connected for either maintenance activities, or to cover transformer or other major equipment failures. The works will vary at each substation but could include additional land, fencing, gravel, earthing and HV/MV connection points. Each site's connection point will only be "made ready" when it will be required to allow an outage for scheduled routine maintenance on major equipment.	$103,725 '23/24 $153,591 p.a. '23/24 & '31/32 $307,182 p.a. '26/27 & '30/31
Communications Upgrade: OJV's current communications infrastructure was installed in 2000. It comprises a UHF link and multipoint base station network for SCADA, and a VHF repeater network for voice communications between mobile field staff, depots and System Control. Since 2000 the electricity industry has experienced dramatic change. The development of advanced digital relays, distributed energy resources and smart metering will place an ever-increasing demand on communications networks. Whilst OJV's existing analogue communications networks have been both reliable and cost effective, the challenge for OJV now is to balance the benefit that modern digital infrastructure brings in the context of the operational environment, with the level of investment required to modernise and futureproof the overall communications infrastructure. Key features of the communications upgrade will be: • A higher capacity backbone network to support enhanced communications across the OJV operating area. • A resilient IP network that incorporates OJV's distributed legacy assets. • A digital mobile radio platform. The project is planned for the 2025-2029 period.	$620,363 p.a. '25/26 to '28/29
Replacement of Overhead Structures with Ground Mounted: This budget is to replace pole mounted distribution transformers greater than 100kVA with ground mount units.	$77,170 p.a. '23/24 & '24/25 $231,511 p.a. '25/26 onward
Ranfurly Transformers Oil Containment & Seismic Strengthening: The two Ranfurly 66/33 kV transformers are to have foundation strengthening work carried out and an oil bund constructed. The bund will contain oil leaks from the transformers.	$172,745 '24/25

Critical Spares: Procurement of a spare 11kV circuit breaker is programmed for 2025/26. The spare unit will provide cover for similar assets on the OJV network.	$55,613 '25/26

Table 62: Non-routine Development Projects (under consideration)

Project Description	CAPEX Cost & Timing
Southern Corridor Zone Substation: Rapid growth in the Wakitipu Basin area indicates that a new zone substation will be required in the long term to provide capacity and diversity. Available options to increase capacity and supply security in the region include: • Plan for a future zone substation to service expected growth. • Upgrade the capacity of Remarkables substation and forgo the diversity a second substation would provide. • No non-asset solutions available. Establishing a new zone substation will provide for future growth and enhance supply security. The project's planned completion date is 2030/31.	$527,384 '28/29 $3,803,250 '29/30 $4,176,985 '30/31
Hyde Transformer Oil Containment & Seismic Strengthening: The Hyde 33/11 kV transformer is to have foundation strengthening work carried out and an oil bund constructed. The bund will contain oil leaks from the transformer.	$134,843 '28/29
Unspecified System Growth Projects: This budget is an estimate of costs for projects that are as yet unknown but are considered likely to arise in the longer term. Certainty for these estimates is obviously low. These projects and this expenditure will eventuate based on customer driven developments and engineering evaluation of network capacity.	$1,061,576 p.a. '28/29 to '32/33

Non-network Development

IT and management services support are provided through the services contract with PowerNet. OJV does not directly develop the GIS or AMIS (Maximo) systems, but in conjunction with PowerNet develop interfaces and processes around these systems.

7.2 Asset and Network Design

The design life cycle stage addresses the following aspects.

- Type of assets used on the networks.
- Network configuration.
- Interactions between various assets and asset systems on the network.
- Physical location of assets.

Design Phase Risks

The following risks are partially addressed in the design life cycle phase.

Table 63: Design Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment Plan
Operational Performance	**Damage due to extreme Physical Event (i.e. Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Locating assets and networks to avoid high event probability areas Design structures and buildings to cater for seismic events
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Designs take maintenance and operations requirements into account. A lower equipment purchase price should not be cost of reliability and should not lead to increased maintenance requirements. Design takes asset retirement and disposal into account
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism	Asset and system design takes physical security into account.
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Designs are standardised to minimise stock levels and create interchangeability of assets.
Operational Performance	**Loss of key critical service provider**	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Standardised design do not lead to single supplier dependencies. A limited number of asset options are available Designs can be implemented by any of a number of competent contractors.
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Design to reduce or eliminate faults due to inclement weather.
Health and Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Safety in Design process takes public exposure to live equipment into account. Asset placement reduces public interaction with the assets. Any new assets are evaluated in terms of safety before they are approved for use on the network.
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Design standards take environmental risk into account Asset do not contain hazardous substances or hazardous substances are controlled

Cost Efficiency

In the interests of cost efficiency, OJV aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost efficient with network development requires a "just enough, just in time" approach for the determination of appropriate new capacity, and an appropriate level of standardisation. Other works within the locale may be brought forward and combined to achieve economies of scale for design, safety, and traffic management costs.

Before capital intensive upgrades are required, the following options, in a broadly descending order of preference, are considered when development triggers have been reached:

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. In reality, do nothing options would only be adopted if the benefit-cost ratios of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive that the do nothing option did not represent an unacceptable increase in risk to OJV. An example of where a do nothing option might be adopted is where the voltage at the far end of a remote rural feeder drops below the network standard minimum level for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low to justify the expense.

- Operational activities, in particular switching on the distribution network to shift load from heavily loaded to lightly loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.

- Demand management using load control or using other methods to influence customers' consumption patterns so that assets operate at levels below trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source to avoid new capacity. OJV notes that the effectiveness of line tariffs in influencing customer behaviour is diminished by the retailer's practice of repackaging fixed and variable charges.

- Install generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. These options would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. waste steam from a process.

- Modify an asset so that the asset's trigger point will move to a level that is not exceeded e.g. by adding forced cooling. This approach is more suited to larger classes of assets such as power transformers. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels but current capacity is not fully utilised.

- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.

Installing new or greater capacity assets is generally the next step which increases asset capacity to a level at which the relevant trigger point is not exceeded. An example would be to replace a 200 kVA distribution transformer with a 300 kVA unit so that the capacity criterion is not exceeded.

For meeting future demands for capacity, reliability, security and supply quality there may be several options within the above range of categories and identifying potential solutions is dependent on the experience and ingenuity of the Engineers undertaking the planning.

Standardisation

Standardisation is an important strategy used by OJV to achieve cost efficiencies. It may not always be obvious that standardisation achieves this outcome; standardised equipment sizes will often mean larger equipment is used than would otherwise be strictly necessary. However, standardising assets allows efficient management of stock and spares, operator familiarisation, standardisation of operation procedures, and simplified selection of equipment and materials. Standardised designs or design criteria also avoid “reinventing the wheel”, simplifies the design process, and can incorporate more learnings than could otherwise be practically managed. The benefits of standardisation easily outweigh the oversizing of assets where significant repetition of a particular network solution occurs.

PowerNet’s Quality Systems (policies, standards and procedures) provide for the documentation and communication of the standards that are applied to OJV’s network. OJV benefits from their close working relationship with the other line owners whose networks are managed by PowerNet, with the standardisation able to be maintained across networks for increased efficiencies. Examples include the keeping of critical spares, which can be more efficiently achieved when shared across the combined network’s asset base; or lessons learnt on one network that can be incorporated into standards which then benefit the other networks. Standardised design is used for line construction with a Construction Manual and standard drawings in use by planners, designers and construction staff.

Standardised designs for projects may be used from time to time where projects with similarities occur within a short enough period of time. Though these opportunities do not arise often on OJV’s network, similar projects are often managed by PowerNet on other networks and where project scopes overlap design “building blocks” may be utilised in several designs. Through this approach a degree of standardisation is achieved, with each consecutive design utilising these building blocks from the latest previous design. Continuous improvement is realised with lessons learnt able to be incorporated at each iteration.

Virtually all of the OJV network assets are standardised to some degree either by being an approved network material or asset type or by selection and installation in line with network standards. Examples of standardisation are listed in Table 64.

Table 64: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300 mm^2 Al	Stocking of common sizes, lower cost
	11 kV Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Fluorine, Helium, Iodine, Neon or	Low corrosion, low resistance, cost, stocking of common sizes
	Aluminium conductor steel reinforced (ACSR) – Flounder, Wolf	Higher strength (longer spans, snow load)
	Low Voltage Aerial Bundled Cable (ABC):35, 50 & 95 mm^2 Al (four core).	Safety, lower cost.
Structures	Poles: Busck pre-stressed concrete	Consistent performance, long life, strength
	Cross-arms: Solid hardwood	Long life, strength.
Line equipment	Standard ratings (e.g. ABS 400 A, field circuit breaker 400 A), manufacturer/type	Cover-all specification, minimise spares, familiarity, environmental (non SF_6)
Power Transformers	Discrete ratings, tap steps, vector group, impedance, terminal arrangements etc.	Ratings match available switchgear ratings, interchangeability, network requirements.
33 kV & 11 kV Switchboards	Common manufacturers, common specification.	Interchangeability spares management.
Protection and Controls	Common manufacturer, communications interface, supply voltage etc.	Minimise spares, familiarity, proven history
Substation equipment	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history
Distribution Transformers	Standard ratings (residential areas - size based on domestic customer numbers), equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.
Ring Main Units	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.

Security

Security is the level of redundancy that is built into the network to provide improved continuity of supply when faults occur. It enables supply to be either maintained or restored independently of repairing or replacing a faulty component. OJV's security standard is therefore crucial for the maintenance of network reliability levels. Security involves a level of investment beyond what is strictly required to meet demand, but maintenance of the desired security level must account for demand growth eroding surplus capacity. Typical approaches to providing security include the following.

- **Provision of Alternative Supplies. T**his is achieved by providing one or more inter-feeder tie switches (interconnection points). Urban areas can naturally achieve a high level of meshing with many tie points between feeders whereas rural area feeders may need significant line extension to meet adjacent feeders. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair. This requires those adjacent feeders to maintain spare capacity.

- **Duplication of Assets.** In normal service both sets of assets share the load. When a duplicated asset malfunctions it can be isolated, and all load can be transferred to the remaining asset. This approach generally provides the greatest security as it can completely prevent interruption to supply; but duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent assets.
- **Generation.** This can be used to either provide an alternate supply, or to partially supplement supply and reduce capacity requirements for backup assets. From a security perspective, generation needs to have close to 100% availability to be of benefit. Diesel generation has good availability and is used occasionally to manage network constraints, although it is too expensive to run for extended periods. Other forms of generation such as run-of-the-river hydro, wind or solar, do not provide the needed availability due to lack of energy storage and so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.
- **Demand Management.** Use of demand management (interruptible load) can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feed on the 11 kV providing an extra level of security. Table 65 summarises the security standards adopted by OJV. An exception to these standards occurs when a substation is for the predominant benefit of a single customer; in this case the customer's preference for security will be documented in their individual line services agreement and will set the minimum security level.

Table 65: Target Security Levels

Description	Load Type	Security Level
AAA	Greater than 12 MW or 6,000 customers.	No loss of supply after the first contingent event.
AA	Between 5 and 12 MW or 2,000 to 6,000 customers.	All load restored within 25 minutes of the first contingent event.
A(i)	Between 1 and 5 MW	All load restored by isolation and back-feeding. Isolated section restored after time to repair.
A(ii)	Less than 1 MW	All load restored after time to repair.

The current security levels for Zone Substations are displayed in the next Table.

Table 66: Security Levels for Zone Substations

Substation	Current Security Level	Required Security Level	Remarks
Charlotte Street (Balclutha)	AAA	AA	Dual 33kV supply to a 33kV indoor switchboard, with three 33kV feeders. Dual 5MVA transformers, 11kV indoor switchboard.
Clarks	A(ii)	A(ii)	Tee off the 33kV radial line beyond Middlemarch. 0.5MVA 22kV SWER substation.

Substation	Current Security Level	Required Security Level	Remarks
Clinton	A(ii)	A(i)	Radial 33kV from Clifton switches. 2.5MVA transformer and outdoor 11kV substation.
Clydevale	A(ii)	A(i)	Two supply routes at 33kV. 5MVA transformer and indoor 11kV substation.
Deepdell	A(ii)	A(ii)	Alternate 33kV lines supplying 0.75MVA transformer and basic 11kV outdoor substation.
Elderlee Street (Milton)	A(i)	A(i)	Supplied off a 33kV ring. Dual 5MVA transformers and 11kV indoor switchboard.
Finegand	A(ii)	A(i)	Three supply routes at 33kV. 2.5MVA transformer and outdoor 11kV substation. A 33kV feed to processing plant.
Glenore	A(ii)	A(ii)	Supplied off a 33kV ring. 1.5MVA transformer and outdoor 11kV substation.
Golden Point	A(ii)	A(i)	Teed off the Deepdell to Palmerston 33kV line. 5MVA transformer with indoor 11kV switchgear.
Hindon	A(ii)	A(ii)	Radial 33kV line to 0.5MVA 22kV SWER and 0.1MVA 11kV substation.
Hyde	A(ii)	A(i)	Alternate 33kV line to a 2.5MVA transformer and outdoor 11kV substation.
Kaitangata	A(ii)	A(i)	Radial 33kV to a 2.5MVA transformer and outdoor 11kV substation.
Lawrence	A(ii)	A(i)	Alternate 33kV lines to a 2.5MVA transformer and indoor 11kV substation.
Linnburn	A(ii)	A(ii)	Temporary substation teed off radial 33kV line to Paerau. 1 MVA transformer and single feeder.
Merton	A(ii)	A(i)	Teed off the radial 33kV Palmerston to Waitati. Dual 2.5MVA transformers and outdoor 11kV substation.
Middlemarch	A(ii)	A(ii)	Radial 33kV from Deepdell to 2.5MVA transformer and outdoor 11kV substation.
Milburn	A(ii)	A(i)	Teed off the Elderlee to Waihola 33kV line. 3/5MVA transformer with indoor 11kV switchgear.
North Balclutha	A(i)	A(i)	33kV line from Balclutha GXP. 5MVA transformer and outdoor 11kV substation.
Oturehua	A(ii)	A(ii)	Teed off the radial 33kV from Ranfurly to Falls Dam. 0.75MVA transformer, outdoor 11kV substation and 33kV regulator for generator connection.
Owaka	A(ii)	A(i)	Radial 33kV line from Finegand. 2.5MVA transformer and outdoor 11kV substation.
Paerau	A(ii)	A(ii)	Radial 33kV from Ranfurly. 1MVA transformer and basic 11kV substation.
Paerau Hydro	A(ii)	AAA	Radial 66kV line from Ranfurly. Dual 7.5M/15VA 66/11kV transformers with 66kV switchyard and indoor 11kV board.
Palmerston	A(ii)	A(i)	Radial 33kV to dual 2.5MVA transformers and outdoor 11kV substation.
Patearoa	A(ii)	A(i)	Teed off radial 33kV line to Paerau, 2.5MVA transformer and outdoor 11kV substation with 33kV regulator for the Paerau line.
Port Molyneux	A(ii)	A(ii)	Teed off radial 33kV line to Owaka. 2.5MVA transformer and outdoor 11kV substation.
Pukeawa	A(ii)	A(ii)	Alternate 33kV lines to a 0.75MVA transformer and basic 11kV substation.
Ranfurly 66/33kV	AAA	AAA	Dual heavy 33kV lines from Naseby GXP to 33/11kV substation and dual 12.5/25MVA 33/66kV transformers, outdoor 66kV structure with two feeders.
Ranfurly 33/11kV	A(ii)	A(i)	Single 33kV line from 66/33kV substation, single 2.5MVA transformer and outdoor 11kV substation.
Remarkables	A(i)	A(i)	Dual 33 kV cables from Frankton GXP to dual 12.5/23 MVA transformers and indoor 22 kV switchroom.

Substation	Current Security Level	Required Security Level	Remarks
(Frankton)			
Stirling	A(ii)	A(i)	33kV line and cable switch-able between two 33kV lines from Balclutha GXP. 5MVA transformer and 11kV indoor switchboard.
Waihola	A(ii)	A(i)	Radial 33kV line off the 33kV ring that supplies Elderlee St and Glenore. 1.5MVA transformer and outdoor 11kV substation.
Waipiata	A(ii)	A(i)	33kV tee off the 33kV line from Ranfurly to Deepdell. 2.5MVA transformer and 11kV indoor switchboard.
Waitati	A(ii)	A(i)	Radial 33kV line from Palmerston and a tee off from the Halfway Bush-Palmerston 33kV line. 2.5MVA transformer and outdoor 11kV substation.
Wedderburn	A(ii)	A(ii)	Teed off the 33kV line from Ranfurly to Falls Dam. 1MVA transformer and outdoor 11kV substation.

Capacity Determination

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within OJV's guiding principle, which is to minimise the long term cost to provide service of sufficient quality under foreseeable demand.

Sizing network equipment carries an investment risk for assets being underutilised if not done correctly. While sizing a particular asset for the present time is relatively straight forward, load growth makes appropriately sizing an asset more difficult, especially for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over investment however if assets are undersized the asset will need to be replaced early before their natural end of life. In many cases standardisation will limit the options available to assist in the selection of capacity. In general, this will mean the balancing of over-investment and under-investment will result in a small amount of over-investment (i.e. increased capacity). However, this is considered to be optimal, due to the often marginal cost of increased capacity versus significant cost of re-work should the investment prove to be under-sized.

Stranding of assets is a risk where new assets are required to supply one (or few) new customers representing the worst case in overinvestment if the expected growth does not eventuate. This stranding risk is particularly significant when network extension outside of the existing network footprint is required as the assets are less likely to be reutilised if the expected load disappears. Stranding risk is generally managed through capacity guarantee contracts with customers to recover expected line charges if necessary.

Relocation of assets provides a way to manage costs efficiently while limiting exposure to the above risks in areas of growth. However this strategy is only of benefit where the material cost dominates the installation cost of establishing an asset; the installation cost cannot be recovered. For example once load grows to a power transformers capacity the transformer can be relocated and used elsewhere so that a larger unit may be installed in its place. In comparison a cable (where trenching and reinstatement dominates installation costs) would typically be abandoned and replaced.

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 67. Clearly understanding load growth into the future is crucial to making sound investment decisions.

Table 67: Capacity Selection Criteria

<table>
<tr><th>Network Asset</th><th colspan="2">Capacity Criteria Selection</th></tr>
<tr><td>Subtransmission network</td><td colspan="2">Allow expected demand growth over life time of assets</td></tr>
<tr><td>Power transformers</td><td colspan="2">Allow expected demand growth over 20 years then relocate</td></tr>
<tr><td>Switchgear</td><td colspan="2">Allow expected demand growth over life time of assets</td></tr>
<tr><td>Distribution and LV cables</td><td colspan="2">Allow growth over expected life when known or otherwise 100% growth over existing load</td></tr>
<tr><td rowspan="4">Overhead distribution and LV lines</td><td colspan="2">Build to standard volt drop from nominal:</td></tr>
<tr><td>Urban</td><td>Rural</td></tr>
<tr><td>11 kV:-3%</td><td>11 kV: -4%</td></tr>
<tr><td>LV: -5%</td><td>LV:-4%</td></tr>
<tr><td rowspan="10">Distribution transformers</td><td colspan="2">Size based on diversity and anticipated medium term load:</td></tr>
<tr><td>Domestic Customers</td><td>Transformer Size</td></tr>
<tr><td>2</td><td>15 kVA</td></tr>
<tr><td>6</td><td>30 kVA</td></tr>
<tr><td>10</td><td>50 kVA</td></tr>
<tr><td>20</td><td>100 kVA</td></tr>
<tr><td>50</td><td>200 kVA</td></tr>
<tr><td>80</td><td>300 kVA</td></tr>
<tr><td>150</td><td>500 kVA</td></tr>
<tr><td>Individual customers</td><td>Size to customer requirements</td></tr>
</table>

Best Option Identification

Of the many possible development options that may be identified for meeting demand and service levels, the option which best meets OJV's investment criteria is determined using a range of analytical approaches. Each of the possible approaches to meeting demand will contribute to strategic objectives in different ways. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options. Table 68 summarises the decision tools used to evaluate options depending on their cost.

Table 68: Cost-based Decision Tools

Cost & Nature of Option	Decision Tools	Approval Level
Up to $75,000: commonly recurring, individual projects not tactically significant but collectively add up.	• OJV standards. • Industry rules of thumb. • Manufacturer's tables and recommendations. • Simple spreadsheet model based on a few parameters.	Project Manager
$75,000 to $250,000: individual projects of tactical significance. Timing may be altered to allow resource focus on higher priority projects.	• Spreadsheet model to calculate NPV that might consider one or two variation scenarios. • Basic risk analysis including environmental and safety considerations. • Consultation with stakeholders if necessary.	GM Asset Management
$250,000 to $1,000,000: individual projects or programmes of tactical or strategic significance. Timing may or may not be flexible depending on priority.	• Extensive spreadsheet model to calculate NPV that may consider several scenarios. • Risk analysis including environmental and safety considerations with consideration to management cost. • Consultation with stakeholders if necessary.	Chief Executive
Over $1,000,000: occurs maybe once every few years, likely to be strategically significant. May divert resources from routine lower cost projects in the short term.	• Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios. • Detailed risk analysis including environmental and safety considerations - represented as cost estimates within NPV and Payback calculations. • Resources (financial, workforce, materials, legal) across AWP need to be balanced across many projects and several years managed through planning meetings and spreadsheet models. • Ongoing stakeholder consultation may be required especially large customers. • Business case presented to the Board, highlighting options considered and justification of recommended option.	Board Approval

Prioritisation of Development Projects

Development projects are prioritised when competition for resources exists in the management of conflicting stakeholder Interests. Safety, viability, pricing, supply quality and compliance is the order of priority for managing the conflicts. These factors cannot be applied generally, as each project will have its own combination of these factors presenting in various degrees. Instead, a weighting approach is used recognising the relative severity of these factors between projects and their importance relative to each other. Each factor also implicitly recognises risk however this may need to be rationalised as it affects the AWP as a whole. The resulting prioritised AWP is presented to the OJV Board for approval with supporting justification in the updated AMP.

Electrification and Energy Efficiency

OJV strives to make decisions based on the best outcome for its customers; customers pay for losses on the network in their energy bills, so it is in the customer's interest to deliver energy as efficiently as possible. However from a customer's benefit-cost point of view, the extra expense of a more efficient asset will generally outweigh the benefit of that asset. In the few cases where there is an economic justification to reduce losses in this way OJV will use these solutions, e.g. specifying low loss cores used in the magnetic circuits of transformers.

Power consumed by OJV and its organisational partners is used responsibly, with substation buildings and PowerNet's office buildings heated using efficient heat pump technology, insulation and draft control etc. where appropriate.

Under EECA's Warm Up NZ Healthy Homes program which came into effect on 1 July 2013, insulation is free for eligible homeowners. Landlords with eligible tenants are also included but will be required to make a contribution. The Healthy Homes scheme targets those who stand to benefit most from having their homes insulated, those being low income households with high health needs, including families with children and the elderly. EECA provides 50% of the funding conditional upon the remaining 50% funding coming from third party funders.

Distributed Generation

The value of distributed generation can be recognised in the following ways.

- Reduction of peak demand at the Transpower GXP.
- Reducing the effect of existing network constraints.
- Avoiding investment in additional network capacity.
- Making a very minor contribution to supply security where the customers are prepared to accept that local generation is not as secure as network investment.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.
- It is also recognised that distributed generation can have the following undesirable effects:
- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset's capacity.
- Raising voltage above regulated levels.
- Can cause safety issues when the network de-energises a line to carry out work.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and OJV is actively encouraged.

Terms and Conditions for Commercial Connections

- Connection of up to 10 kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10 kW to an existing connection may incur additional costs to reflect network up-sizing.
- Distributed generation that requires a new connection to the network will be charged a standard connection fee as if it was a standard off-take customer.
- An application administration fee will be payable by the connecting party.
- Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.
- Any benefits of distributed generation that arise from reducing OJV's costs, such as transmission costs or deferred investment in the network, and provided the distributed generation is of sufficient size (greater than 10 kW) to provide real benefits, will be recognised and shared.
- Those wishing to connect distributed generation must have a contractual arrangement with a suitable party in place to consume all injected energy – generators will not be allowed to "lose" the energy in the network.

Distributed Generation Safety Standards

- A party connecting distributed generation must comply with any and all safety requirements promulgated by OJV.
- OJV reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

Distributed Generation Technical Standards

- Metering capable of recording both imported and exported energy must be installed if the owner of the distributed generation wishes to share in any benefits accruing to OJV. Such metering may need to be half-hourly.
- OJV may require a distributed generator of greater than 10 kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.
- All connection assets must be designed and constructed to technical standards not dissimilar to OJV's own prevailing standards.

Use of Non-Network Solutions

OJV routinely considers a range of non-asset solutions and prefers solutions that avoid or defer new investment. Effectiveness of tariff incentives is lessened with Retailers repackaging line charges in ways that sometimes remove the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels. Load control is utilised for the following.

- Transpower charges by controlling the network load during the LSI peaks.

- GXP load when maximum demand reaches the capacity of that GXP.
- Load on feeders during temporary arrangements to manage constraints.

Load shedding may be used by some customers where they accept a reduction of their load instead of investing in additional network assets. Generators (owned by PowerNet) are used where appropriate for planned work on distribution transformers or LV network, to reduce the reliability impact of the work. Other typical low-cost options include the following.

- Conductor upgrades.
- Voltage regulators.
- Pumps and fans on power transformers.
- Tie point shifts.

There are limits to the capabilities of low investment options to meet growth when the capacity margins are depleted or when demand is significant or occurring in large clusters.

Responses to the impact of Technology

Changes in markets, regulations, and consumer behaviour create opportunities, but also complexities and risks for OJV. Responses to these potential impacts include the following.

- Implementing detailed demand data monitoring and analysis.
- Increasing cross-industry collaboration.
- Trialling new technology to have a better understanding of potential adoption and impact.
- Continuous improvement in communications with customers.

7.3 Asset Acquisitioning

During asset acquisitioning, designed assets are bought and installed. This phase often includes civil construction activities. The prevention and treatment of safety risks are paramount. This life cycle stage partially addresses the following risks.

Table 69: Acquisitioning Phase Risks

Category	Risk Title	Risk Cause	Risk Treatment Plan
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Ensure all new assets going onto the network are reliable – New Assets Process Manage the quality of work by contractors and own staff
Operational Performance	**Damage due to extreme Physical Event (i.e. Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Ensure all assets can withstand potential events they may be subject to. Construct all buildings and structures to be seismically compliant

Category	Risk Title	Risk Cause	Risk Treatment Plan
	Major Contractual Breach	Breach of contractual obligations in place with key counterparties, resulting in legal action with potential serious financial implications and/or reputational damage	Use of standard, vetted contracts – NEC Contract and contractor management
	Unavailability of critical spares	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Ensure that any new assets are supported by a reputable supplier Procure strategic spares and parts when procuring the asset
	Loss of key critical service provider	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Improved identification of critical suppliers and contractors Identify alternative suppliers and contractors Internalise and grow internal workforce so that work can be executed internally
Health & Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Install barriers against inadvertent access to live assets
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Construction methodologies employed cause no environmental harm

Installation of Assets

The drivers for the installation of an asset may change during the asset's operational life. In addition, the viability of maintaining or replacing an asset at end-of-life may also change. These drivers need to be monitored beyond the installation process to ensure that the objective of providing an efficient and cost effective service is achieved.

Standards are used to guide the construction and installation of regular assets such as a distribution transformer, but complex assets (such as a zone substation) will require substantial design work before installation. Equipment and materials are procured (as per the relevant design or standard) and these are implemented according to OJV's standardisation requirements.

Post-installation, the commissioning process follows. This process is either specified in the design or (for standardised installations) in a commissioning checklist. The purpose is to ensure the asset has been installed and will function as intended prior to putting it into service.

Asset Replacement and Renewal

Replacement and renewal programmes have the objective to get the full benefit of assets by replacing them near their economic end-of-life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are reaching end-of-life, while critical assets may be replaced on a fixed time basis. For example, 11kV switchboards at zone substations are generally replaced at the end of their nominal year life. Less critical assets or assets provided with redundancy (as part of security arrangements) may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole-of-life cost analysis, there are several other replacement drivers including operational/public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology. Some of these may be diminished through cost analysis. Asset replacement requirements might also be impacted by the network development driver.

Innovations That Defer Asset Replacement

Although asset age is taken into account in any replacement decision, asset condition is the main driver. There are a number of innovations used for condition assessment that potentially could defer asset replacement. These include the following.

- Thermal (infrared) and partial discharge (Corona) camera inspections of zone substation equipment.
- Mid-life refurbishment of power transformers.
- Dissolved Gas Analysis (DGA) of large distribution transformers.
- Thor hammer analysis of poles.
- Automation of switchgear to enable faster restoration in the event of faults.

The decision-making approach for replacements or renewals applicable to each network asset category is provided in Table 70 .

Table 70: Replacement and Renewal Decisions per Asset Category

Asset Category	Sub Category	Replacement & Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles, cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Subtransmission Voltage (ABSs)	Replacement if inspection/operation indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.

Asset Category	Sub Category	Replacement & Renewal Decision Approach
Zone Substations	Subtransmission Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers	Major refurbishment for transformers is undertaken when units reach half of their expected life. Replaced after failure causing significant damage that is not economic to repair; most units will be allowed to run to failure to utilise entire lifespan unless failure risk is unacceptable. May be replaced if tank and fittings are deteriorating, spare parts are unavailable and not economic to maintain for aged units. May be scrapped if not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit. Paper, Furan and/or DGA analysis used to indicate insulation remaining life.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors not economical to maintain.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic. Otherwise units generally run to failure but transformers supplying critical loads may be replaced early based on age or as part of other replacements at site. Units removed from service <100 kVA and older than 20 years are scrapped; otherwise units testing satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.

Asset Category	Sub Category	Replacement & Renewal Decision Approach
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-routine Replacement and Renewal Projects

Replacement and renewal projects that are once off and underway or planned are described in the following tables. These projects often represent significant assets that have reached end of life or other significant miles stone. Some projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 71: Non-routine Replacement & Renewal Projects (next 12 months)

Project Description	CAPEX Cost & Timing
Port Molyneux Substation Outdoor to Indoor Upgrade: The outdoor switchgear and bus arrangement is at end of life and has seismic strength issues. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution. Available options include: • Replace with new outdoor switchgear • Replace with new indoor switchboard • Redevelop on a new site • No non-asset solutions	$1,595,745 ‘23/24

Project Description	CAPEX Cost & Timing
An indoor conversion offers the best benefit-cost especially given the coastal location. Redevelopment on a different site is not warranted. Work on this project has commenced and it will be completed in 2023/24.	
Palmerston 33kV Substation Feeder CBs Replacement: The three feeder circuit breakers at Palmerston 33kV substation are at the end of their useful life and are exhibiting slow fault clearance times. They will be replaced in 2023/24.	$455,290 ‘23/24

Table 72: Non-routine Replacement & Renewal Projects (next four years)

Project Description	CAPEX Cost & Timing
Quarry Road Substation: The present Merton substation feeding the Waikouaiti area has peak demand above the n-1 capacity of the transformers, and the 11kV and 33kV structures have deteriorating wooden poles and components. The substation is low lying alongside the Waikouaiti River and is prone to flooding and is at risk from tsunami or liquefaction following a seismic event. The substation is beside SH1 to the south of Waikouaiti, its major load centre, meaning there is only one line route to the main loads. Available options include: • Redevelop on the existing site with new transformers and indoor switchgear, raised above possible flood levels. • Build a second substation on the south side of Waikouaiti to provide greater reliability and less dependence on this substation. • Redevelop the substation on a more secure site closer to the load. • No non-asset solutions available. Redeveloping on a new site is the best strategic solution with the lowest future risk. A new site has been secured in Quarry Road close to Waikouaiti. The new substation will be connected to the 110kV lines purchased from Transpower, now converted to 33kV, that run past the site. Connecting the new substation to these 33kV lines will improve security of supply and reduce losses with a more direct supply than the existing configuration. The Merton substation will not be decommissioned until Waitati is able to be supplied by both Halfway Bush-Palmerston 33 kV lines (planned for 2028/29) and the Palmerston-Merton-Waitati coast line is redundant as a 33 kV supply. Part of the coast 33 kV line will be reconfigured as Quarry Road substation 11kV feeders.	$5,137,160 ‘26/27 $225,515 ‘28/29
Ranfurly & Paerau Powerhouse Relay Replacements: The relays providing protection for the 66 kV lines and associated transformers at Ranfurly and Paerau Powerhouse are predominantly the electromechanical type and are approaching end-of-life. Available options include: • Replace with new relays. • Do not replace the relays and accept the increasing risk of eventual failure. • No non-asset solutions. Replacement with modern numerical relays will provide reliable and improved protection and allow improved monitoring and operation of the 66kV network due to the new relays’ SCADA capabilities.	$100,000 ‘23/24 $370,420 ‘25/26

Project Description	CAPEX Cost & Timing
SWER Recloser Replacements: A project to replace sixty-eight old and unsupported hydraulic reclosers which protect SWER distribution commenced in 2020/21. The replacements are modern equivalent reclosers with vacuum interrupters and electronic protection. The project will be completed in 2024/25.	$135,429 '24/25
Glenore Substation Supply Reconfiguration: Glenore's power transformer is the oldest on the network and the 11kV and 33kV structures have deteriorating wooden poles and components. The substation is alongside the Tokomairaro River West Branch and the site has been identified as being within the floodplain[10]. Available options include: • Construct a new zone substation on the existing site and accept the risk of flooding. • Construct a new zone substation on a site outside of the floodplain. • Transfer the Glenore load to adjacent distribution feeders and disestablish the substation. Disestablishing Glenore is the most economic option. Glenore zone substation is located 5km west of Milton's Elderlee Street substation and some load transfer capability exists between the two. Reinforcement of the distribution lines from Milton and new remote controlled field switchgear will allow Glenore's single 11 kV feeder to be transferred to Elderlee Street with minimal reduction in reliability at the distribution level. Glenore is currently supplied from a hard tee off the Balclutha to Kiness 33kV line. After the reconfiguration the subtransmission supply security will be improved because of Elderlee Street's two connections to the Milton 33kV ring.	$803,493 '25/26
Maximum Demand Indicator Upgrade: Larger distribution substations (>=100kVA) are normally fitted with MDIs (Maximum Demand Indicators). The accuracy of these analogue MDIs can be marginal and they only register the peak load between manual readings, providing very limited insight into the real world power flows in the LV network. OJV has therefore planned an upgrade of the Maximum Demand Indicators at distribution substations to provide increased visibility of power flow on the network. This data when analysed will better enable OJV to identify vulnerable points on the LV network and proactively upgrade to remove the weakness. This project commenced in 2021/22 and is planned for completion in 2028/29.	$19,209 p.a. '23/24 & '24/25 $191,659 '25/26 $172,450 p.a. '26/27 to '28/29
Power Transformer Replacements: One very small capacity power transformer is planned for replacement in the ten year planning period. It is a 100kVA 33/11kV unit located at Hindon zone substation which serves a small number of three-phase customer connections[11]. The transformer is at end of life and condition monitoring indicated deteriorating insulation. Replacement is planned for 2024/25.	$97,963 '24/25
Power Transformer Refurbishment: Refurbishment is aimed at extending the expected life of transformers; the resulting deferral of replacements will achieve cost efficiencies in maintaining service for OJV's customers. Three of OJV's zone substation transformers are planned for refurbishment in the ten year planning period. The refurbishments will only be done if condition assessments show they are required.	$132,999 p.a. '25/26, '26/27 & 30/31

[10] 'Flood Risk Management Strategy for Milton and the Tokomairiro Plain' – Otago Regional Council & Clutha District Council.

[11] Most of the customers supplied from Hindon substation are connected to 22kV SWER (Single Wire Earth Return) distribution feeders.

Project Description	CAPEX Cost & Timing
Halfway Bush - Palmerston 33kV Towers Replacement: There are fourteen steel lattice towers between Halfway Bush and Palmerston, supporting dual circuits mainly through suburban Dunedin. Designed for 110kV, the circuits were purchased from Transpower and a project completed to convert them to 33kV to attain subtransmission reliability improvements for Palmerston, Merton and Waitati substations. Condition monitoring of the towers shows that they are approaching replacement criteria. Available options include: • Replace the towers with new structures • Install underground cable and remove the towers • Refurbish the towers to extend their serviceable life • No non-asset solutions At this stage a combination of replacement with underground cables and new structures appears to offer the most economical solution. This recommendation may change pending the outcome of a detailed structural assessment.	$480,549 '26/27 $1,250,897 '27/28
Owaka 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is at end of life and may require additional land for the substation to give adequate clearance to the fences if it was retained. The proximity of the location to the coast increases the vulnerability of the outdoor switchgear to corrosion and salt pollution. Available options include: • Replace with new outdoor switchgear • Replace with new indoor switchboard • Redevelop on a new site with more space • No non-asset solutions An indoor conversion offers the best benefit-cost especially given the coastal location. Redevelopment on a different site is not warranted.	$48,244 '26/27 $764,491 '27/28

The non-routine replacement and renewal projects that are under consideration for the remainder of the planning period is described in Table 73.

Table 73: Non-routine Replacement & Renewal Projects (under consideration)

Project Description	CAPEX Cost & Timing
Palmerston Zone Substation 11kV switchgear & 33kV structure replacement: The Palmerston 33/11 kV substation has dual transformers but is only supplied by a single 2.3km long 33 kV circuit. The 11 kV feeder arrangements are also sub optimal and on an old and difficult to maintain outdoor structure. There are minor clearance issues associated with the 11 kV cable terminations, and substation control equipment is housed within the depot building. The 33 kV structure is constructed with wooden poles and near end of life. Available options include: • Rebuild Palmerston zone substation at the Palmerston 110/33 kV substation site.	$1,024,921 '27/28

Project Description	CAPEX Cost & Timing
• Rebuild the zone substation on the existing site, with new outdoor or indoor switchgear and retain a single 33 kV supply line. • Rebuild the zone substation on the existing site and route a second 33 kV supply line. • No non-asset solutions available. Rebuilding the zone substation on the existing site addresses the condition and safety issues of the existing substation economically while maintaining the current level of reliability.	
Waitati Zone Sub Relocation (Blueskin Bay): The existing substation is flood prone and is located within a residential area. Both the transformer and switchgear are approaching end of life although at present, condition testing is not indicating that end of life is imminent. Conversion of a former 110kV line to 33kV has allowed for redundant 33kV line circuits to be provided most of the way to Waitati, but a section of single 33kV line remains. Available options include: • Do nothing and continue with poor reliability due to 33kV line faults. • Redevelop on the existing site and allow for completion of the dual 33kV circuits. • Redevelop on a new site. Redeveloping on a new site is the best strategic solution with the lowest future risk.	$1,271,741 '27/28 $3,533,148 '28/29
Tower Road Substation: The Elderlee Street zone substation feeding Milton had been approaching its n-1 capacity. However the capacity driver for an upgrade was removed by the closure of timber mills in the area, combined with load transfer capability to the Milburn substation to the northeast. Elderlee Street substation will see a load increase of 0.7 MW when Glenore substation is decommissioned in 2025/26. Including the additional Glenore load, peak load is forecast to exceed n-1 capacity within the ten year planning period. The 11 kV indoor switchgear is approaching end of life and it was planned for replacement in 2026. The existing substation building has been identified as below current building seismic strength requirements. Secondary drivers for replacement include that the present substation is not ideally situated, being in a residential area with potential noise issues and limited room for expansion or renewal. The existing 33kV lines cross industrial land and the railway and future 33kV line easements for a Milburn ring extension will be difficult to obtain. Available options include: • Redevelop on a new site away from the residential area. • Redevelop on the existing site with a new substation and indoor sound proofed transformers. • Replace the transformers only with 7.5MVA units and add bus protection. • No non-asset solutions are available. A new site has been secured in Tower Road across the railway line from Elderlee Street. Project completion is planned for 2030/31.	$527,384 '28/29 $3,803,250 '29/30 $4,176,985 '30/31
Kaitangata 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is at end of life. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution. Available options include: • Replace with new outdoor switchgear	$865,252 '28/29

Project Description	CAPEX Cost & Timing
• Replace with new indoor switchboard • Redevelop on a new site with more space • No non-asset solutions An indoor conversion offers the best benefit-cost especially given the coastal location. Redevelopment on a different site is not warranted.	
Clinton 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is at end of life, has seismic strength issues and many of the air break switches are no longer supported, although OJV has a small stock of spare parts. Available options include: • Replace with new outdoor switchgear • Replace with new indoor switchboard • No non-asset solutions An indoor conversion offers the best benefit-cost and improves the aesthetics of a substation located directly next to State Highway 1.	$883,437 '29/30
North Balclutha 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is approaching end of life, has seismic strength issues and some of the air break switches are no longer supported, although OJV has a small stock of spare parts. Available options include: • Replace with new outdoor structure. • Replace with new indoor switchboard. • Redevelop on a new site. • No non-asset solutions. An indoor conversion offers the best benefit-cost and improves the aesthetics of a substation located directly next to State Highway 1. Redevelopment on a different site is not warranted.	$48,244 '29/30 $764,491 '30/31
Finegand 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is approaching end of life, has seismic strength issues and the air break switches are no longer supported. Available options include: • Replace with new outdoor structure. • Replace with new indoor switchboard. • Redevelop on a new site. • No non-asset solutions. An indoor conversion offers the lowest lifecycle cost.	$48,244 '30/31 $764,491 '31/32
Ranfurly 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is approaching end of life, has seismic strength issues and the air break switches are no longer supported. Available options include: • Replace with new outdoor structure. • Replace with new indoor switchboard. • Redevelop on a new site.	$54,835 '31/32 $868,940 '32/33

Project Description	CAPEX Cost & Timing
• No non-asset solutions. An indoor conversion offers the lowest lifecycle cost.	
Waihola 11 kV Switchgear Replacement: The outdoor switchgear and bus arrangement is approaching end of life, has seismic strength issues and the air break switches are no longer supported. Available options include: • Replace with new outdoor structure. • Replace with new indoor switchboard. • Redevelop on a new site. • No non-asset solutions. An indoor conversion offers the lowest lifecycle cost.	$36,557 '32/33 $579,293 '33/34
Circuit Breaker Replacements: Replacement of outdoor circuit breakers as they reach end of life and risk of failure increases.	$204,075 '29/30 $561,074 '31/32
Unspecified Replacement & Renewal Projects: This budget is an estimate of costs for projects that are as yet unknown but are considered likely to arise in the longer term. Certainty for these estimates is obviously low. These projects and this expenditure will eventuate based on engineering evaluation of asset condition and remaining useful life.	$4,150,914 '31/32 $5,162,924 '32/33

Ongoing Replacement and Renewal Programmes

Ongoing work that tends to recur year after year and can be capitalised, are funded from the remaining replacement and renewal budgets. These budgets are listed and described in Table 74 with the associated capital expenditure estimates.

Table 74: Ongoing Replacement & Renewal Programmes

Budget	Description	CAPEX Cost
Line Replacement & Renewal (LV, SWER, Distribution, Subtransmission)	Work previously identified through condition assessment that is either on-going or planned over the next 5 years. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.	$6,445,387 '23/24 $6,885,177 '24/25 $6,826,087 '25/26 $6,974,387 p.a. '26/27 onwards
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	$93,779 p.a. ongoing
Relay Replacements	This programme allows for the renewal of protection relays and voltage regulating relays with modern protection and control relays. Some relay replacements will occur with other replacement projects, e.g. switchboard replacement projects.	$96,755 '23/24 $119,795 '24/25 $359,510 '25/26 $441,363 '26/27 $128,643 '27/28 $266,956 '28/29

Budget	Description	CAPEX Cost
		$260,887 ‘29/30 $41,702 ‘30/31 $347,338 ‘31/32 $16,126 ‘32/33
Distribution Transformer Replacements	On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished for use as spares. Also for replacement of distribution transformers removed due to a fault.	$169,009 p.a. ‘23/24 to ‘25/26 $886,678 p.a. ‘26/27 onward
ABS Renewals	On-going replacements of air-break switches which are generally identified during distribution inspections and targeted inspections based on age.	$220,687 p.a. ‘23/24 to ‘25/26 $269,728 p.a. ‘26/27 onward
Distribution - General	Replacement of LLN distribution equipment removed due to a fault.	$29,217 p.a. ongoing
RTU Replacements	On-going replacement of SCADA Remote Terminal Units as they reach end of life and risk of failure increases.	$20,793 p.a. ‘23/24 & ‘25/26 $109,487 ‘26/27 $72,777 ‘27/28 $103,967 ‘28/29 $31,190 ‘29/30 $83,174 ‘30/31 $51,984 ‘31/32

Asset Relocations

The following are drivers for asset relocations.

- Change in capacity requirements – move an asset that is under capacity or underutilised to a more suitable position and install a new asset in its place.
- Relocate assets due to redevelopment of the area where they are e.g. Balclutha Community Hub, paid for by the developer.
- Customer requests – paid for by customer.
- Changes in the risk profile.

Quality of Supply Improvements

By reducing the number of unplanned interruptions and their frequency, the impact of SAIDI and SAIFI is limited. The following quality of supply improvements are implemented.

- More control points – segmentation of the network.
- Automation e.g. reclosers.
- Remote control.

7.4 Commissioning of Assets

The commissioning life cycle phase addresses the following aspects and risks are presented in Table 75.

- Ensuring that the assets or asset systems functionally deliver to the design specifications.
- System integration – ensuring that the new assets integrate with the existing assets and networks.
- Communication between the new assets and the control systems.
- Documenting the asset characteristics such as capacity, settings, as-built drawings, maintenance requirements, location, test results etc.
- Updating the AMIS and SCADA system to reflect the new asset.
- Training of staff on the maintenance and operation of the equipment.

Table 75: Commissioning Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Network Performance	Failure of Asset Lifecycle Management	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	System integration is tested Asset characteristics and maintenance requirements are captured in the information systems
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	Testing the communication between the new assets and the control systems.

7.5 Capital Expenditure Forecast

The capital expenditure forecast is presented in Table 49 and provided in the Information Disclosure Schedule 11a.

Table 76: Capital Expenditure Forecast ($000 - constant 2023/24 terms)

Category	DPP3			DPP4					DPP5	
CAPEX: Consumer Connection	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Customer Connections (≤ 20kVA)	906	906	906	906	906	906	906	906	906	906
Customer Connections (21 to 99kVA)	160	160	160	160	160	160	160	160	160	160
Customer Connections (≥ 100kVA)	330	330	330	330	330	330	330	330	330	330
Major New Connections Projects	3,624	4,265	3,688	4,800	4,780	4,976	4,602	4,602	4,577	4,577
	5,020	5,661	5,084	6,195	6,176	6,372	5,997	5,997	5,972	5,972

CAPEX: System Growth	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Patearoa Substation Upgrade		813	994							

Puketoi Area Regulator & Line Upgrade		520								
Easements	6	6	6	6	6	6	6	6	6	6
Milton Area Capacity Upgrade	72				214					
Maniototo Road-Lower Gimmerburn 11kV Line			192							
General LNL Network Growth			142	142	142	142	142	142	142	142
New Zone Substation Land			538							
QLDC Arterial (CBD)	35	35								
Kawarau South Bank Cable & Southern Corridor	137	137	137	137						
Frankton Road 22kV Extension	444		400	400						
Southern Corridor Zone Substation						527	3,803	4,177		
Unspecified System Growth Projects						1,062	1,062	1,062	1,062	1,062
	693	**1,511**	**2,408**	**684**	**362**	**1,737**	**5,013**	**5,387**	**1,210**	**1,210**

CAPEX: Asset Replacement and Renewal	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
LV Line Replacement and Renewal	848	848	848	848	848	848	848	848	848	848
SWER Line Replacement and Renewal	565	565	565	565	565	565	565	565	565	565
11 kV Line Replacement and Renewal	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479	3,479
33 kV Line Replacement and Renewal	1,554	1,994	1,935	2,083	2,083	2,083	2,083	2,083	2,083	2,083
Zone Substation Minor Replacement	94	94	94	94	94	94	94	94	94	94
Relay Replacements	97	120	360	441	129	267	261	42	347	16
Distribution Transformer Replacements	169	169	169	887	887	887	887	887	887	887
Quarry Road Substation				5,137		226				
Owaka 11 kV Switchgear Replacement				48	764					
Port Molyneux Substation Outdoor to Indoor Upgrade	1,596									
Kaitangata 11 kV Switchgear Replacement						865				
Clinton 11 kV Switchgear Replacement							883			
Halfway Bush - Palmerston 33kV Towers Replacement				481	1,251					
Palmerston Zone Sub 11kV switchgear & 33kV structure replacement					1,025					
Waitati Zone Sub Relocation (Blueskin Bay)					1,272	3,533				
SWER Recloser Replacements		135								
Maximum Demand Indicator Upgrade	19	19	192	172	172	172				
Tower Road Substation						527	3,803	4,177		
ABS Renewals	221	221	221	270	270	270	270	270	270	270
Glenore Substation Supply Reconfiguration			803							
Palmerston 33kV Sub Feeder CBs Replacement	455									
North Balclutha 11 kV Switchgear Replacement							48	764		
Finegand 11 kV Switchgear Replacement								48	764	
Ranfurly & Paerau Powerhouse Relay Replacements	100		370							
Circuit Breaker Replacements							204		561	
Ranfurly 11 kV Switchgear Replacement									55	869
Waihola 11 kV Switchgear Replacement										37
Power Transformer Refurbishment			133	133				133		

Power Transformer Replacements		98								
RTU Replacements	21		21	109	73	104	31	83	52	
Distribution - General	29	29	29	29	29	29	29	29	29	29
Unspecified Replacement & Renewal Projects									4,151	5,163
	9,246	**7,770**	**9,218**	**14,776**	**12,940**	**13,948**	**13,485**	**13,501**	**14,184**	**14,338**

CAPEX: Asset Relocations	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Network Chargeable Capital	314	36	36	36	36	36	36	36	36	36
Milton Main Street Undergrounding	1,525									
	1,839	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**

CAPEX: Quality of Supply	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Finegand 33kV smart network automation	935									
Supply Quality Upgrades	12	12	12	12	12	12	12	12	12	12
Network Improvement Projects		182	182	138	138	138	138	138	144	144
Mobile Substation site made ready	104	154		307				307	154	
Northlake to Clearview Link Cable			142							
RMU SCADA & Communications				29	29	29	29	29	29	29
	1,051	**348**	**337**	**486**	**179**	**179**	**179**	**486**	**339**	**185**

CAPEX: Legislative and Regulatory	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CAPEX: Other Reliability, Safety and Environment	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Substation NERs and 33kV Transformer Circuit Breakers	108	167	495							
Communications Upgrade			620	620	620	620				
Substation arc-flash upgrades	92									
Replacement of OH Structures with Ground Mounted	77	77	232	232	232	232	232	232	232	232
Earth refurbishment from earth testing, incl. SWER	603	603	603	575	397	397	397	223	223	223
Critical Spares			56							
Ranfurly Transformers Oil Containment & Seismic Strengthening		173								
Hyde Transformer Oil Containment & Seismic Strengthening						135				
	881	**1,020**	**2,005**	**1,427**	**1,249**	**1,383**	**628**	**455**	**455**	**455**

Total Network CAPEX	18,730	16,346	19,088	23,604	20,941	23,655	25,338	25,862	22,196	22,196

CAPEX: Non-Network Assets	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Palmerston Depot Building	20									

Palmerston Depot Fencing	7
	27

Values Fully Marked Up, No Inflation, Base Year dollars.

7.6 Retiring and Disposal of Assets

Retiring of assets generally involves de-energising the asset and disconnecting it from the network before removal from site or abandoning in-situ (typical for underground cables). The follow risks are addressed in this life cycle stage.

Table 77: Retiring Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Assets are removed from the network when they start to affect reliability
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy particular locations (e.g. Aerial trespass, subdivision)	Historical land use rights are formalised should the land be required for the installation of new assets.
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Where practical, removed assets or asset components are kept to be utilised in the repair of existing assets.
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Assets containing hazardous materials are identified and disposed of using national and international guidelines

Removed assets will be eliminated from the regulatory asset base and needs to be disposed of in an acceptable manner particularly if it contains SF6, oil, lead or asbestos. Key criteria for retiring an asset includes the following.

- It is no longer required, usually because a customer has reduced or ceased demand.
- It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.
- There are no suitable opportunities for re-deployment after an asset has been replaced to increase capacity or where more economic options exist to create similar outcomes e.g., new technology offers a low cost maintenance free replacement.
- It is uneconomical to maintain the asset and more cost effective to being replaced.
- The asset has reached end-of-life.

8 Operating Expenditure

8.3 2024-34 Update Asset Operation

PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake. PowerNet has developed a Business Continuity Plan using the nationally deployed Coordinated Incident Management System (CIMS) which has the following principal objectives:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.
- Minimise financial loss.
- Provide for a timely resumption of operations in the event of a disaster.
- Reduce or limit exposure to potential liability claims filed against the Company, its Directors, and Staff.
- Coordinate with other services in the event of a regional or national significant event.

In developing the business continuity plan each business unit identified their key business functions and prioritised them according to their criticality and the timeframes before their absence would begin to have a major impact on business functions. Where practicable continuity plans have been developed in line with each critical business function and preparation undertaken where appropriate to allow continuity plans to be implemented should they be required.

Operational Expenditure Forecast

The operational expenditure forecast is presented in Table 78 and provided in the Information Disclosure Schedule 11b.

Table 78: 2024-34 Update Operating Expenditure Forecast ($000 - constant 2024/25 terms)

Category	DPP3	DPP4					DPP5			
OPEX: Asset Replacement and Renewal	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
Network Chargeable Maintenance	11	13	13	13	13	13	13	13	13	13
Subtransmission Replacement and Renewal	15	15	15	15	15	15	15	15	15	15
Distribution Replacement and Renewal	67	67	67	67	67	67	67	67	67	67
Distribution Transformer Replacement and Renewal	14	17	17	17	17	17	17	17	17	17
Zone Substation Replacement and Renewal	30	36	36	36	36	36	36	36	36	36
Power Transformer Replacement and Renewal	25	30	30	30	30	30	30	30	30	30
Locks and Security	82									
	244	**178**	**178**	**178**	**178**	**178**	**178**	**178**	**178**	**178**

OPEX: Vegetation Management	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34

Vegetation Management	1,265	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
	1,265	**1,087**	**1,087**	**1,087**	**1,087**	**1,087**	**1,087**	**1,087**	**1,087**	**1,087**

OPEX: Routine and Corrective Maintenance and Inspection	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Customer Connections Maintenance	1	1	1	1	1	1	1	1	1	1
Transmission Line Minor Maintenance	84	102	102	102	102	102	102	102	102	102
Distribution Routine Inspections	1,090	1,090	1,187	1,090	1,090	1,090	1,090	1,212	1,090	1,090
Distribution Routine Maintenance	167	167	225	232	240	255	226	208	234	234
Distribution Corrective Maintenance	78	104	104	104	104	104	104	104	104	104
Technical Routine Inspections	351	351	351	351	351	351	351	351	351	351
Technical Routine Maintenance	786	798	899	1,311	954	1,012	1,107	622	1,310	1,310
Technical Corrective Maintenance	249	257	257	257	257	257	257	257	257	257
Infrared Survey	13	18	16	18	16	18	16	18	16	18
Partial Discharge Survey	16	7	17	7	17	7	17	7	17	7
Radio Equipment	28	28	28	28	28	28	28	28	28	28
Supply Quality Checks	6	7	7	7	7	7	7	7	7	7
Spares Checks and Minor Maintenance	5	5	5	5	5	5	5	5	5	5
Earth Maintenance	47	47	46	49	49	49	49	49	49	49
LV Network Conductor Inspections	98	98	98							
	3,020	**3,082**	**3,345**	**3,564**	**3,221**	**3,287**	**3,361**	**2,973**	**3,572**	**3,564**

OPEX: Service Interruptions and Emergencies	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Incident Response - Distribution	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
Incident Response - Technical	212	212	212	212	212	212	212	212	212	212
	2,208	**2,208**	**2,208**	**2,208**	**2,208**	**2,208**	**2,208**	**2,208**	**2,208**	**2,208**

Operational Expenditure Total	6,737	6,556	6,819	7,038	6,695	6,761	6,835	6,447	7,046	7,038
System Operations and Network Support	1,220	1,692	1,925	1,925	1,925	1,925	1,925	1,925	1,925	1,925
Business Support	2,907	2,986	3,039	3,039	3,039	3,039	3,039	3,039	3,039	3,039

AMP Total Operational Expenditure	10,864	11,233	11,784	12,003	11,660	11,726	11,800	11,412	12,011	12,003

Values Fully Marked Up, No Inflation, Base Year dollars.

Expenditure categories were described in the 2023-33 AMP:

Operating Expenditure (OPEX) is required to operate and maintain OJV's networks. The following objectives are pursued with operating expenditure initiatives.

- Comply with customer obligations and service standards.
- Maintain the safety of the distribution system.

- Assets are operated and maintained in a manner that minimises system life cycle cost with due consideration of risk.
- Electricity delivery networks and associated electrical systems are maintained in such a manner that the requirements of customers, internal stakeholders and legal authorities related to such networks are met at minimum life cycle cost.

8.1 The Operation and Maintenance Lifecycle Phase

The operations and maintenance (O&M) lifecycle phase starts once the assets have been commissioned and are handed over to the Operations Unit. This is the stage where the majority of life cycle expenditure occurs. The physical assets are expected to perform their function at specified performance and reliability levels.

Continuous improvement of O&M activities is a key component of the asset management process as O&M practices can significantly impact asset lifecycle costs, management of risk and service delivery performance. The manner in which an asset is operated and maintained directly determines the performance, reliability and life expectancy of the asset.

O&M Phase Risks

The following risks are addresses during the O&M phase.

Table 79: Operation & Maintenance Phase Risks

Category	Risk Title	Risk Cause	Treatment Plan
Operational Performance	**Damage due to extreme Physical Event (i.e. Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g. floods, earthquakes)	Structures are inspected and maintained to retain structural functionality
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure, ineffective maintenance ineffective fleet plans Budget constraints Lack of future network planning	Asset fleet plans outlining the maintenance actions for each type of asset is being incorporated into the AMIS (Maximo) Maintenance execution is being managed to ensure all assets are maintained Operating instructions and manuals are accessible to ensure asset are operated correctly
	Operational systems failure due to breakdown in telecommunications	SCADA communications has one centralised communications point that all information is passed through.	Regular testing of the telecommunications systems
	Intentional Damage	Terrorism, theft, vandalism Reputation	Programme to replace locks and improve security being implemented
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Spares will be recorded in Maximo Education of staff on spares process and locations

Category	Risk Title	Risk Cause	Treatment Plan
	Loss of key critical service provider	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Improved identification of critical suppliers Identify alternative suppliers Grow the capabilities of the internal workforce
	Major event triggering storm gallery activation	Damage caused by wind, snow, storm events	Monitor developing weather Ensure people, vehicles, equipment and spares are on call and/or available during storm events
Health & Safety	**Public coming into contact with live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Access prevention barriers are treated as assets and maintained to be in good condition
Regulatory Change & Compliance	**Major legislative breaches**	Failure to meet legal obligations, for example: - Obligation to supply electricity - Price quality regulation breach - Low fixed charge regulations - Employment legislation - Metering recertification	Utilise the Planned Interruption SAIDI and SAIFI allocations optimally by planning work more effectively

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at OJV's expense as required under the Electricity (Hazards from Trees) Regulations 2003. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As OJV's network is mostly overhead, tree issues are pronounced and therefore costs are relatively high. This OPEX cost is budgeted at $1,212,717 for 2023/24 & 2024/25. The increase in cost is due to a two-year programme to address a backlog of trimming. From 2025/26 onwards the provision for vegetation management is $1,041,835 per annum.

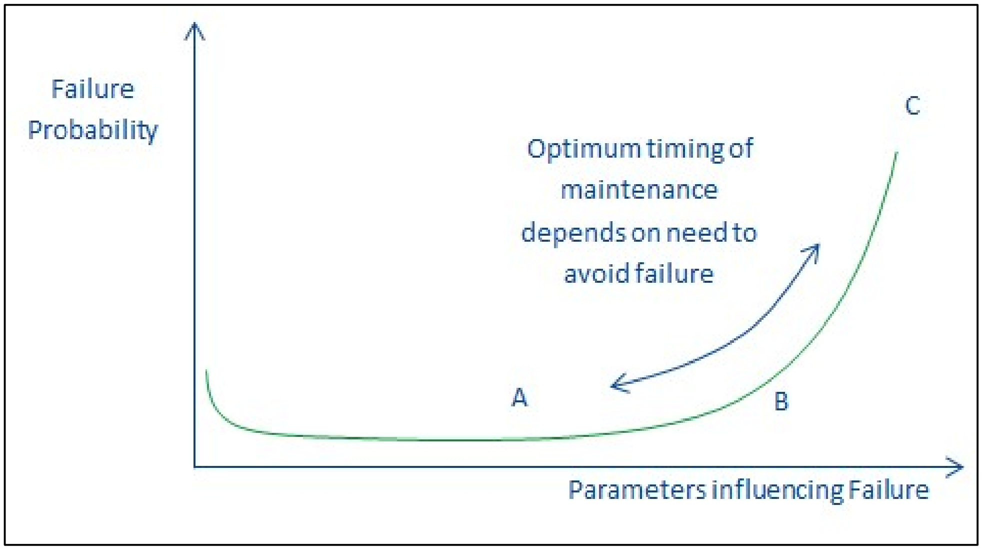
8.2 Asset Maintenance

The maintenance aspect of the O&M lifecycle phase is aimed at ensuring that assets will achieve their expected useful lives. Asset maintenance is not intended to upgrade an asset or extend its life to beyond what is expected life.

Maintenance is primarily about replacing consumable components. Many of these components will be designed to "wear out" during an asset's design life and achieving the expected service life depends on such replacements. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, or loss or contamination of lubricants.

Continued operation of such components will eventually lead to failure as indicated in Figure 49. Exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, ambient temperature, previous maintenance history and presence of contaminants.

Figure 49: Component Failure



The probability of failure curve can be viewed as applicable to the overall asset life in which case neglecting maintenance could result in a considerable contraction along the “parameters influencing failure” axis. Appropriate maintenance activities would stretch out the curve toward the expected design life; effectively resetting or pushing out the increasing probability of failure. There is often a significant asymmetry associated with consumables for example replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the asset’s life.

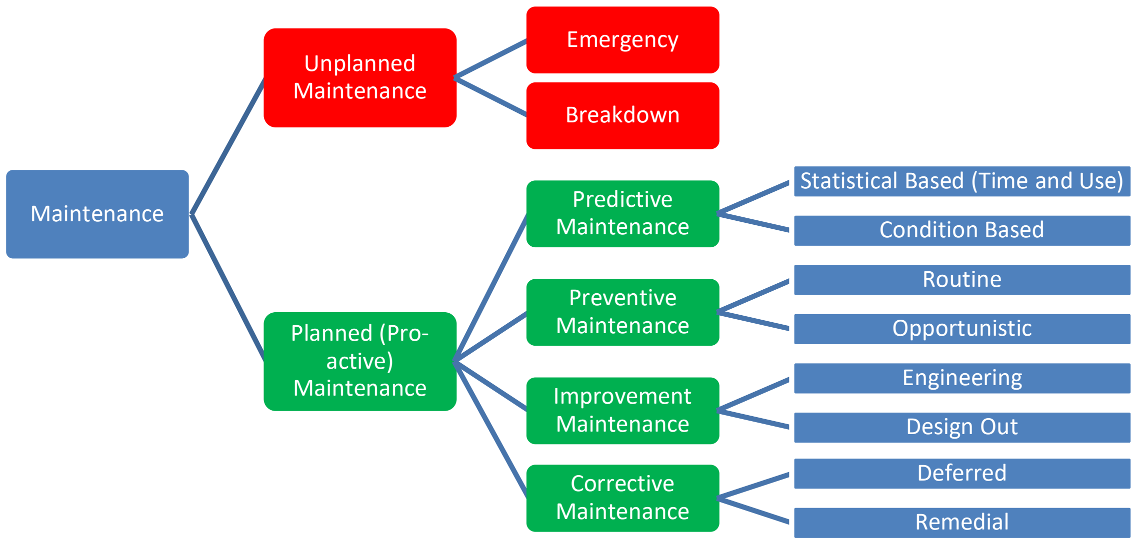
OJV’s maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset’s lifecycle, taken together with the cost of discarding unused component life, must be traded off against the desire to avoid failure. The optimal time for maintenance depends on an asset’s criticality (impact of failure on customers) and ultimately on how much OJV’s customers are willing to pay to reduce probability of failure.

Assets such as a 33/11 kV substation transformer, supplying large customers or large numbers of customers, may only be operated to point B in Figure 49 and condition will be extensively monitored to minimise the likelihood of supply interruption. Meanwhile assets supplying merely a small number of customers, such as a 10 kVA transformer, will most often be run to failure represented as point C.

Maintenance Actions

Types of maintenance activities are presented in the next figure.

Figure 50: Structure of Maintenance Actions



Planned versus Unplanned Maintenance

Condition assessment is an important part of determining maintenance requirements because many components do not deteriorate at a predictable age. Condition assessment allows deferral of maintenance cost for assets that are in good condition and permits maintenance to be focused on the more deteriorated assets. Condition assessment involves inspections and testing to gather information about the condition of assets and their components and can incorporate follow-up analysis (condition monitoring) to infer the condition of the asset through establishing trends in observable criteria.

By contrast some components are maintained at fixed intervals or operation counts. An example is replacing contacts in a circuit breaker which are pitted or eroded with each operation but are unable to be inspected without dismantling the circuit breaker (by which time the contacts can be replaced with a relatively small incremental cost).

As the value and/or criticality of an asset increase, the company relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on comprehensive analysis of component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

Most technical equipment such as transformers, switchgear and secondary assets are maintained in line with manufacturer’s recommendations as set out in their equipment manuals. Experience with the same types of equipment may provide reason to add additional activities to this routine maintenance. Visual inspections and testing also determine reactive maintenance requirements to maintain the serviceable life of equipment which are not routine, but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults so the basic approach is to inspect these assets and perform preventative maintenance over the most cost effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to avoid. This recognises customers' acceptance of a low number of outages and the increasing cost for diminishing returns in attempting to reduce fault frequency.

As cables are underground, they are unable to be visually inspected, and testing is generally not cost effective; it is difficult to obtain accurate results and to use them to predict time to failure. Cables are therefore often run to failure. However as the relatively young cable network ages and fault frequency begins to increase a more preventive strategy will be employed based on testing to determine condition for critical cables.

In terms of cost efficiency, failures are more acceptable for lines and cables than for ring main units and zone substation assets. Significant service life can be restored to lines and cables by simply repairing the fault. Asset criticality is a consideration in determining an acceptable level of outages, however increased security (redundancy) is often a more effective strategy than attempting to determine time to failure and performing preventative maintenance.

Maintenance Approaches

Table 80 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 80: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition assessment through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	3-5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks, opportunistic inspection if covers removed for other work, sheath insulation IR test. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Annual
	Distributed Subtransmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Lubrication of moving parts.	5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
Zone Substations	Subtransmission Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly
	Power Transformers	Condition monitoring through periodic inspections. Winding & insulation resistances, Function checks on auxiliaries (Buchholz, pressure relief, thermometers). Predictive maintenance - oil analysis (dissolved gases, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary. Tap changer servicing: mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances. Clean up and repair of corrosion, leaks etc. and replacement of deteriorated or damaged components. Replacement of breathers when saturated. Paper sample may be taken to estimate age for aged transformers in critical locations at Engineers instruction or otherwise during major refurbishment at half-life. Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	Monthly Annual Operation count Non-periodic
	Distribution Voltage Switchgear	Condition assessment through periodic visual inspection checking for: operation count, gas pressure, abnormal or failed indications and general condition. Testing: Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics. Corrective maintenance as required after any concerning inspection or test results.	Monthly 5 Yearly Non-Periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-Periodic
Distribution Network	O/H	Condition assessment through periodic visual inspection.	3-5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500 kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly (or 5-yearly if <150 kVA) Opportunistic Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge. Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	6 monthly 5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. Overhead structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Network assets are inspected routinely with the frequency dependent on the criticality of the assets and the outcome focussing on failure avoidance. Inspections are not practical for all assets, for example cables buried underground, and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Routine inspections are mostly limited to what can be viewed from a walkover of the assets.

Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection. Deterioration noted may trigger corrective maintenance if economic, especially where significant further deterioration can be avoided, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved), for example pole rotting, and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e. loss of structural integrity.

Visual or more intrusive technical inspection of an asset are often used to determine the condition of the asset. Testing supplements network inspections, and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Data gathered can be qualitative rather than quantitative, allowing more precise trending of an asset's condition over time. Testing may be destructive or non-destructive; for example insulation resistance (IR) testing simply gives an ohmic value for insulation under test, while very low frequency (VLF) testing causes damage if the cable is not in sufficiently good condition to pass the test.

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 81. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice. An increase is projected years 2025/26 onwards in anticipation of increased maintenance activity following the period of constrained renewal in 2020 – 2025.

Table 81: Maintenance Activities and Opex Costs

Budget	Description	OPEX Cost
Distribution Routine Inspections	All work where the primary driver is the five yearly network inspections (20% inspected annually), or other routine tests on distribution assets. Includes routine testing of earthing assets and connections to ensure safety and functional requirements are met (completed five yearly), and any minor maintenance works carried out during these inspections.	$695,800 - $953,597 p.a. '23/24 to '32/33
Technical Routine Inspections	All work where the primary driver is routine inspection and testing of Technical assets, for example oil DGA, earth mat testing, and protection testing. Includes any minor maintenance carried out during these inspections.	$218,913 - $265,481 p.a. '23/24 to '32/33
Distribution Routine Maintenance	All work where the driver is reactive work undertaken to correct issues found during the routine inspection. Also a general budget for all minor distribution work.	$160,000 - $243,306 p.a. '23/24 to '32/33
Technical Routine Maintenance	All work where the primary driver is inspection and testing of Technical assets of sufficient depth to require de-energisation of the asset. Includes any servicing activities (such as oil processing, CB oil replacement, or recalibration of relays) carried out while the equipment is de-energised for these inspections.	$594,250 - $1,252,161 p.a. '23/24 to '32/33
Distribution Corrective Maintenance	Permanent repairs carried out on faulted Distribution assets that had temporarily been made safe/functional during the initial incident response.	$74,420 p.a. '23/24 & '24/25 $98,954 p.a. '25/26 to '32/33
Technical Corrective Maintenance	Permanent repairs carried out on faulted Technical assets that had temporarily been made safe/functional during the initial incident response.	$234,307 p.a. '23/24 & '24/25 $241,949 p.a. '25/26 to '32/33
Earth Maintenance	Minor maintenance and repair of earthing assets.	$44,342 – $46,644 p.a. '23/24 to '32/33
Transmission Line Minor Maintenance	Generally reactive work undertaken to correct issues found on subtransmission lines during the routine line condition survey. Also a general budget for all minor subtransmission work.	$80,246 p.a. '23/24 & '24/25 $96,972 p.a. '25/26 to '32/33
Partial Discharge Survey	Partial discharge condition monitoring of equipment to identify abnormal discharge levels before failure occurs.	$5,877 – $16,467 p.a. '23/24 to '32/33
Infra-Red & Corona Survey	Infra-Red and Corona Discharge condition monitoring survey of bus-work, connections, contacts etc. An Infra-Red survey checks for abnormal heating as an indication of poor electrical contact between current carrying components, which may lead to voltage quality issues and/or failure of equipment; while Corona Discharge testing looks for ionisation of air around insulators, as evidence of insulation defects or contamination.	$12,672 – $17,486 p.a. '23/24 to '32/33
Radio Equipment	Maintence carried out on radio based communications equipment.	$26,587 p.a. ongoing
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	$5,581 p.a. '23/24 & '24/25 $6,604 p.a. '25/26 to '32/33

Budget	Description	OPEX Cost
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	$4,316 p.a. '23/24 & '24/25 $5,107 p.a. '25/26 to '32/33
Customer Connections Maintenance	Operational portion of expenditure for the customer connections process is captured in this budget.	$1,142 p.a. '23/24 & '24/25 $1,380 p.a. '25/26 to '32/33
LV Network Conductor Inspections	A three year programme to identify and capture low voltage and streetlight circuit data.	$93,840 p.a. '24/25 to '26/27

Asset Component Replacement and Renewal

Component renewals or refurbishments are significant maintenance activities that generally focus on the non-consumable components of assets to achieve an extension to the originally expected life. This is typically less routine work and often represents a significant milestone in the life of an asset. Renewal may ultimately be part of a full asset replacement programme where the component replacements are "staggered" over time. A typical example is an overhead line, where the components (poles, cross-arms, and conductors) wear out and are replaced at different rates, but the result is complete replacement of the original line – perhaps several times over as long as the line asset is required.

Ultimately an asset will reach end of life when it either fails or deteriorates to the point it becomes uneconomic to repair or maintain. This will occur when failure causes significant damage to the overall asset (highly likely at distribution or subtransmission voltages) or when a part of the asset that cannot be economically replaced has significantly aged or deteriorated, for example paper insulation in a transformer.

The replacement and renewal budgets for ongoing operational work that tends to recur year after year are listed and described in Table 82.

Table 82: Component Replacement and Renewal Programmes

Budget	Description	OPEX Cost
Distribution Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	$62,891 p.a.
Zone Substation Replacement & Renewal	All OPEX work where the primary driver is the repair of zone substation assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative	$27,870 p.a. '23/24 & '24/25

Budget	Description	OPEX Cost
	maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like earth sticks, safety equipment, buildings, battery systems etc.	$33,679 p.a. ‘25/26 to ‘32/33
Distribution Transformer Replacement & Renewal	All OPEX work where the primary driver is the repair of distribution transformer assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes work that will have a material effect on the functionality or the life of capital assets, i.e. CAPEX. Covers items like enclosure repairs, paint touch-ups, etc.	$13,173 p.a. ‘23/24 & ‘24/25 $15,918 p.a. ‘25/26 to ‘32/33
Power Transformer Replacement & Renewal	All OPEX work where the primary driver is the repair of power transformers such as rust repairs, paint touch-up, oil treatment or renewal, replacement of minor parts such as bushings, seals etc.	$23,568 p.a. ‘23/24 & ‘24/25 $28,481 p.a. ‘25/26 to ‘32/33
Subtransmission Replacement & Renewal	All OPEX work where the primary driver is the repair of subtransmission assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	$14,446 p.a.
Network Chargeable Maintenance	Maintenance carried out at least partially at customer expense, e.g. pole shifts or third-party damage repairs.	$9,858 p.a. ‘23/24 & ‘24/25 $11,912 p.a. ‘25/26 to ‘32/33
Locks and Security	Upgrading the locks and security of all assets to minimise the risk of unauthorised access.	$76,853 ‘23/24 $56,853 ‘24/25

8.3 Asset Operation

The operations aspect of the O&M lifecycle phase refers to the day-to-day activities required to provide service delivery to OJV’s customers. Operation of the network is effectively the service that OJV’s customers pay for so it is the customer desire which forms the driver for the continuous operation of assets the optimal balance between reliability and cost.

Well-planned and executed operations allows OJV to deliver energy supply services efficiently, effectively, and economically. In the asset management context, this requires the business to set service delivery priorities through budgeting and infrastructure planning and investment processes.

Operation of OJV’s assets predominantly involves creating the path for electricity to flow from the GXPs to customer’s premises year after year with occasional intervention when a trigger point is exceeded. However the workload arising from tens of thousands of trigger points is substantial enough to merit a dedicated control room. Altering the operating parameters of an asset such as closing a switch or altering a voltage setting involves no physical modification to the asset, but merely a change to the asset's state or configuration.

Contingencies to Manage Operational Risks

The following tactics have been or are being implemented to manage operational risks (especially for HILP events).

- Align asset design with current best practice.
- Regular inspections to detect vulnerabilities and potential failures.
- Remove assets from risk zone.
- Build appropriate resilience into network assets.
- Provide redundancy of supply to large customer groups.
- Involvement with the local Civil Defence.
- Prepare practical response plans.
- Operate a 24hr control centre.

In addition to the tactics listed above, OJV has the following specific contingencies in place through its management company PowerNet.

PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake. PowerNet has developed a Business Continuity Plan which has the following principal objectives:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.
- Minimise financial loss.
- Provide for a timely resumption of operations in the event of a disaster.
- Reduce or limit exposure to potential liability claims filed against the Company, its Directors and Staff.

In developing the business continuity plan each business unit identified their key business functions and prioritised them according to their criticality and the timeframes before their absence would begin to have a major impact on business functions. Where practicable continuity plans have been developed in line with each critical business function and preparation undertaken where appropriate to allow continuity plans to be implemented should they be required.

PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause significant numbers of staff to be unable to function in their job. The plan aims to manage the impact of an influenza type pandemic on PowerNet's staff, business and services through two main strategies:

- Containment of the disease by reducing spread within PowerNet achieved by reducing risk of infected persons entering PowerNet's premises, social distancing, cleaning of the work environment, managing fear, management of cases at work and travel advice.
- Maintenance of essential services if containment is not possible achieved through identification of the essential activities and functions of the business, the staff required to carry out these tasks and special measures required to continue these tasks under a pandemic scenario.

This plan was activated in 2020-21 due to COVID-19 and may need to be activated again should another outbreak of COVID-19 occurs. The plan is available as a separate document.

Critical Network Spares

Critical network equipment has been identified and spares kept ensuring reinstatement of supply or supply security is achievable in an appropriate timeframe following unexpected equipment failure. Efficiencies have been achieved due to close relationship between the networks which PowerNet manage.

Network Operating Plans

As contingency for major outages on the OJV network PowerNet holds network operating plans for safe and efficient restoration of services where possible. For example a schematic based switching plan and accompanying operating order detailing steps required to restore supply after loss of a zone substation.

Insurance

OJV holds the following insurances:

- Material damage and business interruption over Substations and Buildings
- Contracts works and marine cargo
- Directors' and officers' liability
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires, Products liability, and Professional Indemnity
- Statutory liability
- Contractors working on the network hold their own liability insurance

Service Interruptions and Emergencies

This provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. Any follow-up actions necessary to make further repairs are charged to the appropriate Corrective Maintenance budget. The Service Interruptions & Emergencies budget is set at $2,108,292 per annum.

Operational Expenditure Forecast

The operational expenditure forecast is presented in Table 78 and provided in the Information Disclosure Schedule 11b.

Table 83: Operating Expenditure Forecast ($000 - constant 2023/24 terms)

Category	DPP3				DPP4				DPP5	
OPEX: Asset Replacement and Renewal	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**
Network Chargeable Maintenance	10	10	12	12	12	12	12	12	12	12
Subtransmission Replacement and Renewal	14	14	14	14	14	14	14	14	14	14
Distribution Replacement and Renewal	63	63	63	63	63	63	63	63	63	63
Distribution Transformer Replacement and Renewal	13	13	16	16	16	16	16	16	16	16
Zone Substation Replacement and Renewal	28	28	34	34	34	34	34	34	34	34
Power Transformer Replacement and Renewal	24	24	28	28	28	28	28	28	28	28
Locks and Security	77	57								
	229	**209**	**167**	**167**	**167**	**167**	**167**	**167**	**167**	**167**

OPEX: Vegetation Management	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Vegetation Management	1,213	1,213	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042
	1,213	**1,213**	**1,042**	**1,042**	**1,042**	**1,042**	**1,042**	**1,042**	**1,042**	**1,042**

OPEX: Routine and Corrective Maintenance and Inspection	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Customer Connections Maintenance	1	1	1	1	1	1	1	1	1	1
Transmission Line Minor Maintenance	80	80	97	97	97	97	97	97	97	97
Distribution Routine Inspections	696	696	696	929	745	747	747	747	954	745
Distribution Routine Maintenance	160	160	160	215	222	229	243	216	199	223
Distribution Corrective Maintenance	74	74	99	99	99	99	99	99	99	99
Technical Routine Inspections	219	219	219	259	262	265	265	260	263	256
Technical Routine Maintenance	675	750	761	858	1,252	910	966	1,057	594	1,251
Technical Corrective Maintenance	234	234	242	242	242	242	242	242	242	242
Infrared Survey	15	13	17	15	17	15	17	15	17	15
Partial Discharge Survey	6	15	7	16	7	16	7	16	7	16
Radio Equipment	27	27	27	27	27	27	27	27	27	27
Supply Quality Checks	6	6	7	7	7	7	7	7	7	7

Spares Checks and Minor Maintenance	4	4	5	5	5	5	5	5	5	5
Earth Maintenance	44	45	45	44	47	47	47	47	47	47
LV Network Conductor Inspections		94	94	94						
	2,242	**2,418**	**2,477**	**2,908**	**3,030**	**2,707**	**2,770**	**2,836**	**2,558**	**3,031**

OPEX: Service Interruptions and Emergencies	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Incident Response - Distribution	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906	1,906
Incident Response - Technical	202	202	202	202	202	202	202	202	202	202
	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108

Operational Expenditure Total	6,523	6,489	6,398	6,378	6,593	6,270	6,333	6,399	6,122	6,594
System Operations and Network Support	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993
Business Support	2,040	2,020	2,072	2,020	2,020	2,020	2,020	2,020	2,020	2,020

AMP Total Operational Expenditure	9,825	9,960	9,859	10,238	10,360	10,037	10,100	10,166	9,888	10,361

Values Fully Marked Up, No Inflation, Base Year dollars.

9 Execution Capacity

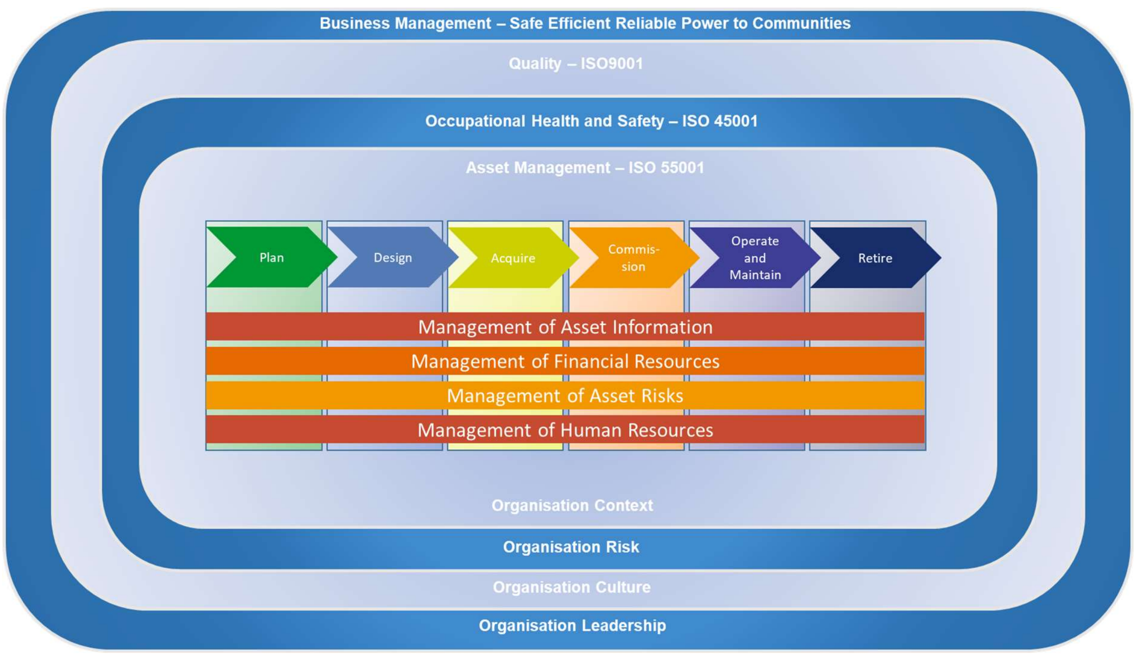
The core of OJV's asset management activities lies within the detailed processes and systems that reflect OJV's thinking, manifest in OJV's policies, strategies and processes and ultimately shape the nature and configuration of OJV's fixed assets.

The Execution Capacity constraints have not changed from 2023-33:

The core of OJV's asset management activities lies within the detailed processes and systems that reflect OJV's thinking, manifest in OJV's policies, strategies and processes and ultimately shape the nature and configuration of OJV's fixed assets.

PowerNet is the contracted asset management company for OJV and uses its integrated Business Management System (BMS) to manage the networks. The BMS can be depicted as per the following figure:

Figure 51: Business Management System



This figure illustrates the asset lifecycle approach that we use in managing the assets of OJV. Each of the lifecycle stages as well as the underpinning foundational elements are discussed in this AMP.

It is important to note that all asset lifecycle activities are executed within the framework of our Safety Management System. The highest priority in all decision-making is to ensure the safety of the public and our staff. This is built into every lifecycle activity.

Asset Management and Safety are both managed within our Quality Management System (QMS). The QMS ensures that approved processes are followed, and that necessary documentation is available to staff and is current. This leads to work being executed in a consistent manner across the whole company and for all managed networks.

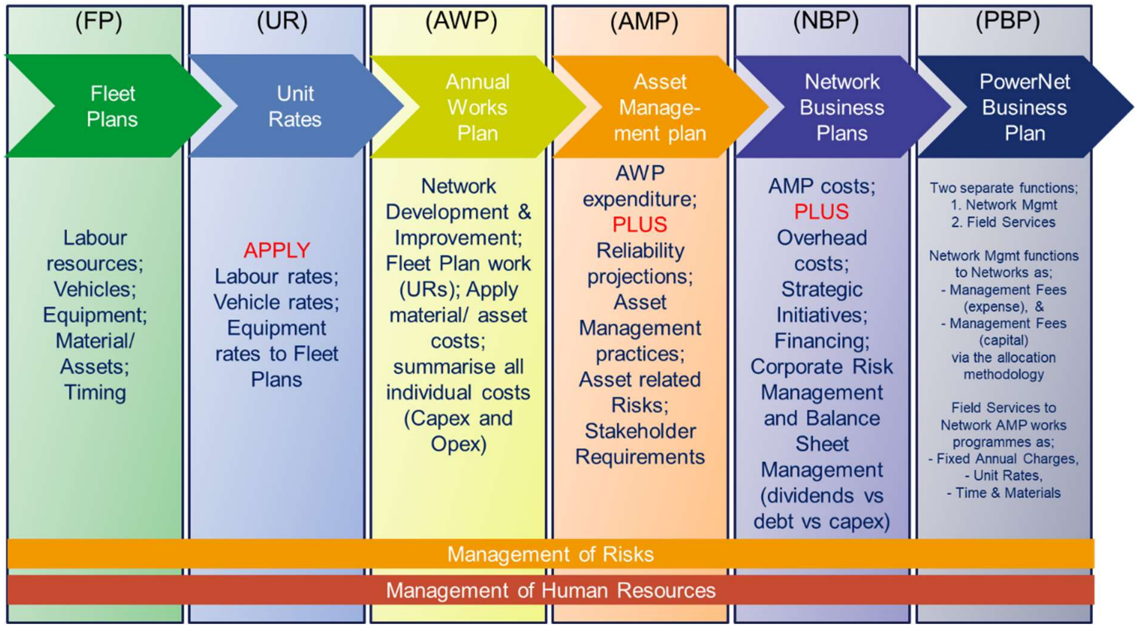
The foundation for managing the assets and determining the required resources and funding is our Fleet Plans. The Fleet Plans:

- Outline how we manage each asset over its full life; and
- How we extract the maximum value from each asset by:
    - Trading-off Capex with Opex; looking at the full life costs
    - Optimising maintenance tactics for each asset class and type
    - Determining risk associated with each asset class/type (e.g. safety, transformer oil spills, etc)
    - Take into account disposal cost and implications (e.g. disposing of SF_6)

The Fleet Plans contain staffing and equipment requirements for each piece of work. Rates such as hourly rates and travel rates are applied to the information in the Fleet Plans to give us a cost for each piece of work. This gives us the Unit Rates that is charged to the networks by PowerNet.

The Annual Works Plan consolidates all the work that needs to be done on the network and the cost thereof into a single document that is used for the development of the AMP and the PowerNet and network Business Plans. The information is arranged into the Commerce Commission format as per Table 49 (Capital Expenditure) and Table 78 (Operating Expenditure) in the AMP. This value chain is depicted in the following diagram.

Figure 52: Business Management Value Chain



9.1 People, Culture and Leadership

OJV's work has to be planned, managed and executed by people. Organisational leadership and culture are key determinants in the efficacy of work execution by people.

The OJV leadership consists of the OJV and PowerNet Boards and the PowerNet SLT. The OJV Board sets and monitors the network performance objectives, evaluates and addresses network and OJV related risks and makes the funding available to PowerNet to execute the required work. The PowerNet Board sets the policies that govern work execution and employees, evaluates and addresses staff and PowerNet related risks and ensures that the requirements of the OJV Board is met.

The PowerNet SLT manages the assets of OJV on their behalf to ensure that the value generated from these assets are optimised. They also manage the employees and determine the culture and values employed in executing the required work. The SLT identifies and manages the risks associated with both OJV and PowerNet and does the medium and long term business and operational planning that is then approved by the relevant board.

Culture and Values

PowerNet SLT is striving and working to develop a culture based on the following values:

- Up front and honest
- Make a difference

- Do it once, do it right
- Back each other; and
- Take positive action.

We believe that this will us to achieve our critical success factors of:

- Safety always
- Customer focus
- Continuous improvement
- Passionate & empowered people
- Courageous leadership

These values and critical success factors align with our vision of having asset management as the core of the organisation, encompassed by safety and quality.

Work Execution Requirements

The way we determine the work execution requirements is by determining the man hours and other resources required to execute each item of work or project. The planned Works Programme is analysed to determine the overall resource requirements for the work execution. Adjustments are then made based on resource availability. These adjustments may be delaying work until resources become available, using contractors or, if there is a long-term resource requirement, appointing additional staff or procuring the required plant or equipment. The year-to-year work volumes in the AWP is smoothed out to prevent peaks and troughs in resources required (to the extent possible acknowledging appropriate risk controls) in order to provide a relatively constant work stream.

Utilising PowerNet's works management and field services staff has great benefit in ensuring a longer term approach may be taken to resourcing. Staff numbers can be increased with added confidence that they will be fully utilised in future years given the long-term plans developed, as these resources can be utilised on all the PowerNet managed networks. The smoothing out of resource requirements can be done over a larger base load of work.

Working closely with OJV's contractors is also an important part of the AWP development process. The detailed works plan is communicated to the contractors they commit to making sufficient resources available for the years ahead. Contractors can confidently commit to hiring extra staff where appropriate, recognising OJV's on-going development and maintenance requirements.

People related constraints

It remains problematic to obtain the required numbers of appropriately skilled resources. This applies to all levels of staff, but particularly to technical and field staff. The lower South Island is not a first choice for people to work and stay, especially younger people. We generally have around 20 vacancies for field and technical staff. PowerNet has appointed 15 trainee linesmen to try and alleviate the shortage, but it will take time to get them to the required level of competency to be fully productive.

9.2 Funding the Business

Revenue

OJV's revenue comes primarily from retailers who pay for the conveyance of energy over OJV's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the Commerce Commission. The following approaches for funding of new assets are utilised.

- Funding from revenue within the year concerned
- Funding from after-tax earnings retained from previous years
- Raising new equity (very unlikely given the current shareholding arrangement)
- Raising debt (which has a cost, and is also subject to interest cover ratios)
- Allowing Transpower to build and own assets which allows OJV to avoid new capital on its balance sheet, but perhaps more importantly also allows OJV to treat any increased Transpower charges as a pass-through cost.

Expenditure

Expenditure is incurred to maintain the asset value of and to expand or augment the network to meet customer demands. In addition, there is a management fee paid to PowerNet for managing the networks on behalf of OJV.

Influences the Value of Assets

An annual independent telephone survey is undertaken each year and consistently indicates OJV's customer's price-quality trade-off preferences are as follows.

- A large majority are not willing to pay $10 per month more in order to reduce interruptions
- A small minority are willing to pay $10 per month more in order to reduce interruptions
- A small minority feel they don't know or are unsure of price-quality trade-offs

In response, OJV's asset value should either remain about the same or be allowed to decline in a controlled manner (and knowing how to do this is obviously a complex issue). However, this presents OJV with the dilemma of responding to customers' wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and in fact revenue incentives to improve reliability. Factors that will influence OJV's asset value are shown in Table 84 below:

Table 84: Factors influencing OJV's asset value

Factors that increase OJV's asset value	Factors that decrease OJV's asset value
Addition of new assets to the network	Removal of assets from the network
Renewal of existing assets	On-going depreciation of assets
Increase of standard component values implicit in valuation methodology	Reduction of standard component values implicit in valuation methodology

At a practical level OJV's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However, the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

Depreciating the Assets

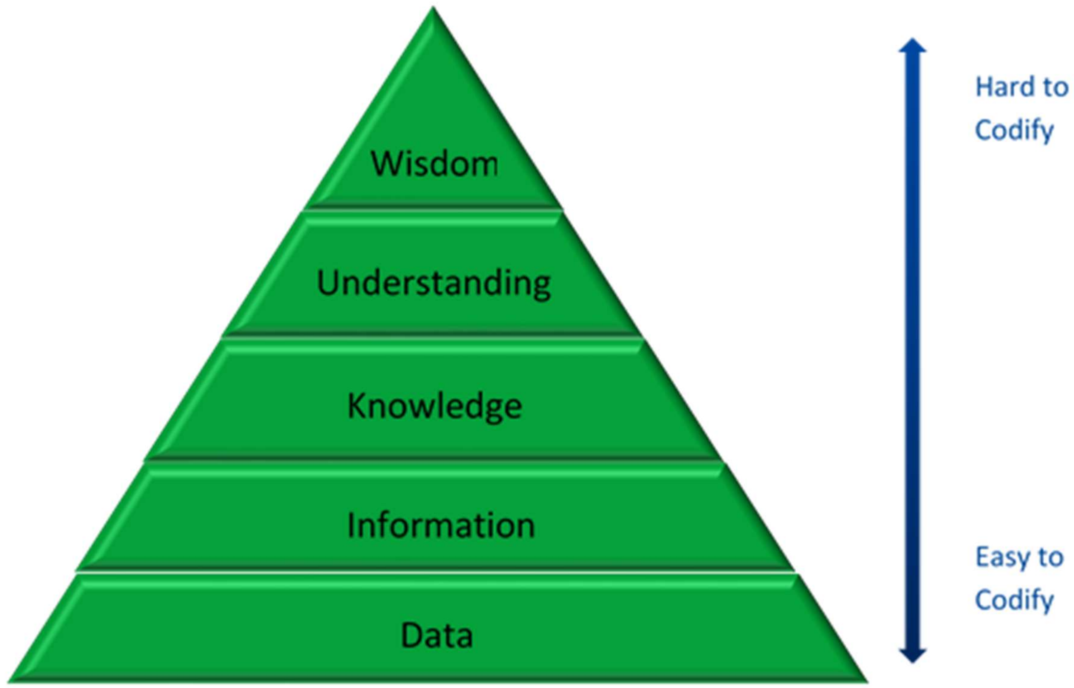
Assets are depreciated using straight line depreciation over the asset expected life. This doesn't strictly model the decline in service potential of an asset. Assets mostly to remain serviceable until it has rusted, rotted, acidified, or eroded substantially and then fails quickly. Straight-line depreciation does, however, provide a smooth and reasonably painless means of gathering funds to renew assets reaching the end of their life. This will be particularly important as the potential "bow wave" of asset renewals approaches.

9.3 Information Management

Information Management Model

The data hierarchy model in Figure 53 shows the typical information and knowledge residing within OJV's business (including employees from PowerNet).

Figure 53: OJV's Data Hierarchy Model



The bottom two layers of the hierarchy, '*Data'* and '*Information'* strongly relate to OJV's asset and operational data and the summaries thereof impacts OJV's decision making. The middle layer, '*Knowledge',* tends to be general in nature and may include technical standards, policies, processes, operating instructions and spreadsheet models. This probably represents the upper limit of what can be reasonably codified of accumulated knowledge.

The top two layers '*Understanding'* and '*Wisdom'* are extensive, often quite fuzzy and enduring in nature. The decision-making process involves these top two levels of the hierarchy and key organisational strategies and processes reside at these levels.

Accurate decision making requires the convergence of both information and (a lot of) knowledge to yield a correct answer. Deficiencies in either area (incorrect data, or a failure to correctly understand issues) will lead to wrong outcomes. The layers right from "*Data*" to "*Wisdom*" are difficult to codify and suitable application depends on skilled and experienced people.

The following outlines the types of investments targeted within the planning period to support improved network visibility:

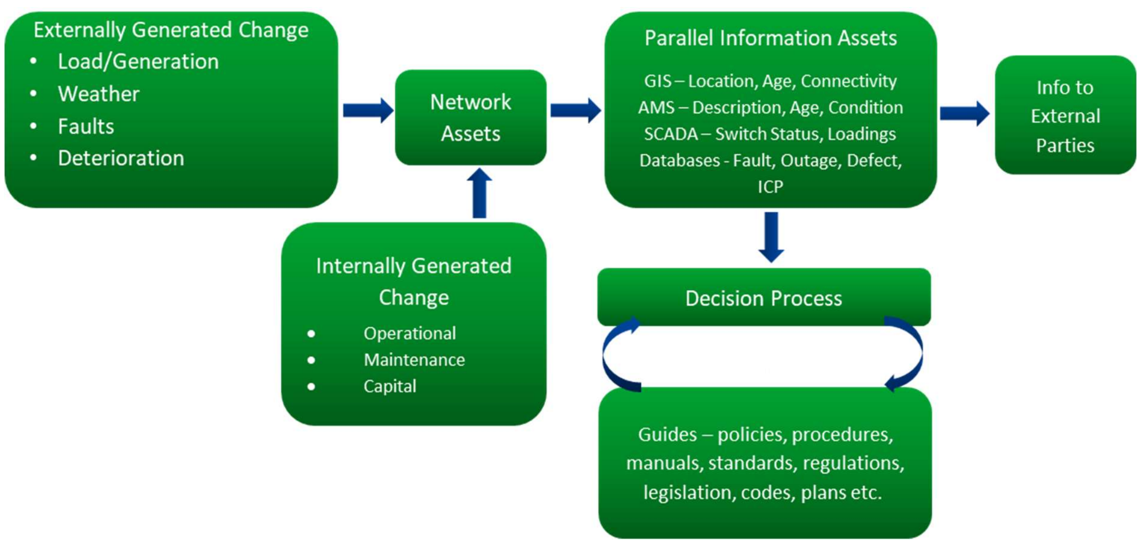
- **LV network monitoring** - This is an essential programme that will inform future investment plans, provide inputs for automation schemes, and help ensure network stability in the face of increased use of distribution edge devices. Over time, we intend to expand visibility further down into the networks – typically to include feeder endpoints and T-offs. The programme will also look at the integration of other available monitoring devices on the network – for example customers' inverters (for PV), smart meters etc.

- **Enhanced network condition and utilisation monitoring** - Incorporating new and different network condition detection methods through expanded sensor types, external sources of network specific data, and improved back office capability.
- **Interfacing with DER resources on the LV network** - Developing methods to provide network relevant data to DER resources (and their management interface) and obtain data from these sources. This will include developing methods of exchanging information with local generation, storage and discretionary loads, such as EVs.
- **Expanded communications and information systems** -We will also identify potential opportunities to share infrastructure with other providers, for example, should the required network insights be available from retailers' smart meters, it may obviate the need for our own investment.

OJV's Asset Management Information Systems

Figure 54 provides a high-level summary of OJV's asset management processes and systems. The role and interaction of each component of the data hierarchy model (Figure 53) are incorporated.

Figure 54: Key Asset Management Systems & Processes



There are a variety of information management tools which capture asset data and can be used to create summary information from the data. Based on this foundation, OJV has sufficient knowledge about almost all the assets; their location, what they are made of, how old they are in general and their performance. This knowledge will be used for either making decisions within OJV's own business or assisting external entities with resolutions. A summary of the key data repositories is listed in Table 85.

Table 85: Key Information Systems

Information System	Data Type	Data Source
Asset Management System (AMIS – Maximo)	Description, Age, Condition	Network Equipment Movement (NEM) Forms, Field Survey, Supplier Data, Commissioning Records, Test Records
Geographic Information System (GIS)	Location, Age, Connectivity	As-built information, Roading Authorities, Land Surveys
SCADA	Switch Status, Loading	Polled devices
PowerNet Connect	Customer Details	MARIA registry, GIS
PowerNet Connect	Customer calls regarding faults	Customer calls to System Control
Outage Reporting System	Regulatory recording of outages SAIDI & SAIFI	System Outage Logs
Defect Database	Equipment failures	System Control, Reports from field staff, Project Managers

In general, the completeness of data within the information systems is reasonable and a summary with noted limitations is provided in the next table.

Table 86: Data Completeness within Information Systems

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Reasonable	Equipment ages include some estimate by type (era of manufacture)
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMIS	Description	Okay	Some delays between job completion and Maximo update
AMIS	Details	Okay	Some delays between job completion and Maximo update
AMIS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMIS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

Data Control, Improvement and Limitations

OJV's original data capture emphasised asset location and configuration. The data was used to populate the GIS, but it did not include high-level asset condition data. As part of this original data capture, the company developed a field manual of drawings and photos to minimise subjectivity.

Records and drawings have been used to ascertain asset age, but certain asset classes such as cables, had limited supporting information. Old cables do not have a manufacturing date associated and updating the GIS system with missing data entry points is problematic. Options have been considered to get ages measured for the un-dated cables but no economic methodology has been found. Where economical, condition data is collected, as it is useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry; and for all other data (for example electrical connectivity), thorough processes, peer reviews, and well-trained staff are used to ensure data entry quality is very good. Key process improvements will include timelier as-builts with PowerNet staff taking GPS coordinates for poles and use of electronic or scannable forms for data input (Teleform System).

Data for the AMIS is collected by the Network Equipment Movement (NEM) form that records every movement of serial numbered assets. Some updating of data is obtained when sites are checked with a barcode label put on equipment to confirm data capture and highlight missed assets. About 20% of the network (by length) is condition assessed each year to update asset condition data (noting that asset condition is continually varying), and any discovered variances are corrected.

Improvements to the AMIS are continually being undertaken to allow additional asset details to be captured which were historically captured in spreadsheets; especially the addition of condition-based indicators to assist in making better asset management decisions. Data validation and completeness controls are also being added over time to prevent new assets being created without all required data being captured.

Assets are assigned a unique reference common to both the GIS and AMIS. Where asset data is common to both systems it will be input into one system (deemed the master for that data) and automatically copied to the other to ensure consistency. Other systems also have some degree of interface for copying across common data such as customer data residing in both the ICP database and in GIS and referenced by the common ICP number. However, for the most part, these tools do not interact directly, with staff pulling together information from the necessary tools for their use as part of their asset management activities.

The SCADA system and monitoring completeness and accuracy is excellent at zone substations as it is critical for both safety and reliability of the network as it is used for the day-to-day operation of the network. More field devices are being added to SCADA for remote monitoring and operation.

Other data repositories have very good data quality with these database systems controlling data entry through drop down lists and validation controls. Modifications may be made from time to time to better align with maintenance processes as they evolve.

PowerNet's Software Systems

PowerNet maintains and utilises several software-based tools to manage data and knowledge of OJV's network assets efficiently and effectively. These are described below.

- **Asset Management Information System (AMIS)**

  This system stores OJV's asset descriptions, details, age and condition information for serial numbered components. It also provides work scheduling and asset management tools with most day-to-day operations being managed through the AMIS. Maintenance regimes, field inspections and customers produce tasks and/or estimates, that are sometimes grouped and a 'work order' issued from the AMIS which is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling. The individual assets that make up large composite items such as substations are managed through the AMIS in conjunction with other more traditional techniques such as drawings and individual test reports. OJV utilises the Maximo software package for its AMIS.

- **Geographic Information System (GIS)**

  An Intergraph based GIS is utilised to store and map data on individual components of distributed networks. The GIS focuses primarily on geographically distributed assets such as cables, conductors, poles, transformers, switches, fuses and similar items and provides asset description, location and age information for each asset. Locational data is used to provide mapping type displays of existing equipment for planning network upgrades, extensions and maintenance scheduling. It allows these plans to account for distance and travel time and any other factors influenced by the geographic distribution of the assets. Electrical connectivity, capacity and ratings also form a crucial data set stored in the GIS which assists the analysis of the networks ability to supply increasing customer load or determine contingency plans.

- **Load Flow and Fault Analysis Software**

  Export of data from the GIS into this system allows modelling of the network. This helps predict network capability in the existing arrangement and in future "what if" scenarios considered as planning options as well as determining fault levels to assess safety and effectiveness of protection and earthing systems. Two software packages PSS Adept and Cyme are used to perform this analysis for OJV.

- **Supervisory Control and Data Acquisition (SCADA) System**

  The SCADA system provides real time operational data such as loads, voltages, temperature, and switch positions. It also provides the interface through which PowerNet's System Control staff can view the data through a variety of display formats and remotely operate SCADA connected switchgear and other assets. Historical data is stored and provides a reference for planning. For example, network loading can be downloaded over several years allowing growth trends to be determined and extended to forecast future loading levels.

- **Finance One (F1) Financial System**

  Monthly reports from F1 provide recording of revenues and expenses for the OJV line business unit. Project costs are managed in PowerNet with project managers managing costs through the AMIS system. Interfaces between F1 and the AMIS track estimates and costs against assets.

- **Outage, Fault and Defect Databases**

  These are populated by the System Control staff as information is reported by field staff or via the faults call centre to ensure efficient tracking of operational issues affecting network service levels.

  - The faults database logs all customer-initiated calls reporting power cuts or part power to store reported information and contact details. Calls are therefore able to be tracked to ensure effective response and restoration.
  - The outage database logs outage data used to provide regulatory information and statistics on network performance. As such data capture is in line with regulatory focuses, it excludes LV network outages. Reports from this system are used to highlight poorly performing feeders which can then be analysed to determine maintenance requirements or if reliability may be enhanced by other methods. Monthly reports are provided to the OJV Board for monitoring, together with details of planned outages.
  - Asset defects are captured in another database for technical asset issues which do not have an immediate impact on service levels but potentially could, if not responded to. Defects are tracked in this database and scheduled for remediation.

- **Condition Assessment Database**

  This database tracks the results of routine overhead line inspection rounds and is used as a basis for assigning line repair/renewal work. Severely deteriorated structures are marked as red-tagged and are prioritised for repair, and low conductor spans are also marked for a heightened priority. The current database is being replaced as part of an overhaul of line inspections on all PowerNet-managed networks; the replacement database will permit the recording of repairs and will allow more precision in reliability analysis.

- **ICP/Customer Database**

  An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history resides in this database system. This interfaces with the National Registry to provide and obtain updates on customer connections and movements. Customer consumption is monitored by another ACE Computers system ‘BILL’. BILL receives monthly details from retailers and links this to the customer database.

Processes and Documentation

OJV's key asset management processes and systems are based around the asset lifecycle activities and the AS/NZS9001 Quality Management System. The processes are not intended to be bureaucratic or burdensome but are intended to guide OJV's decisions (apart from safety related procedures which do contain mandatory instructions). Accordingly these processes are open to modification or amendment if a better way becomes obvious.

The asset management processes are documented and grouped in the following categories with a complete list provided in Annexure 1.

- Operating Processes and Systems.
- Maintenance Processes and Systems.
- Renewal Processes and Systems.
- Up-sizing or Extension Processes and Systems.
- Retirement Processes and Systems.
- Performance Measuring Processes.
- Other Business Processes.

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

The processes are documented in ProMapp. This is process mapping software that makes it easy for all employees to view our processes step-by-step so that they can better understand them and ensure consistency in the way work is being executed, continuous improvement, quality assurance, and risk management.

Document and Process Reviews

Each document or process is controlled by an owner at management level who is given responsibility for its review and update. The documents and processes are reviewed periodically to ensure they are kept up to date. Lean Management practices have recently been introduced to refine business and asset management processes with the changes identified ultimately reflected in documented procedures.

Once updates have been finalised, they are approved by the controlling manager and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals affected. External audits of specific systems and processes are also conducted. Current external audits include the following.

- Public Safety Management System (PSMS) (AS/NZS 7901 compliance).
- Occupational Health and Safety Management (AS/NZS 4801 compliance).
- Worksite safety audits (completed by Network Compliance Ltd).
- AMMAT review.
- AMP format and compliance review.
- Spend forecast assessment.
- Spend approval process review.

10 Evaluation of Performance

10.1 2024-34 Update Progress against Plan

The performance between estimated expenditure and actual expenditure for CAPEX and OPEX is described below.

Capital Expenditure

The variation of estimated expenditure versus actual capital spending is presented in Table 87.

Table 87: Variance between Capital Expenditure Forecast and Actual Expenditure ($000)

Capital Expenditure	Forecast 2022/23 ($k)	Actual 2022/23 ($k)	Variance
Consumer Connection	5,019	7,426	48%
System Growth	865	1,020	18%
Asset Replacement and Renewal	8,605	10,405	21%
Asset Relocations	34	383	1,026%
Quality of Supply	293	195	(33%)
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	997	722	(28%)
Capital Expenditure on Network Assets	**15,813**	**20,151**	**27%**

Capital works varied from budget due to:

- Customer Connections – 48% overspent due to high levels of customer driven demand for subdivision reticulation, and more small new customer connections than allowed for.
- System Growth – 18% overspent due to more than expected new medium voltage cabling works for load growth.
- Asset Replacement and Renewal – 21% overspent mainly due to higher spending on line renewal than planned, including subtransmission, distribution and LV lines. Additional spending on ABS, distribution transformer and circuit breaker replacements also contributed to the overspend. Meanwhile there was lower expenditure in other areas due to delays on a substation project, and less Remote Area Power Supply project work than planned.
- Asset Relocations – Budget overspent by a significant margin due to unforeseen works relocating and undergounding power lines for third parties.
- Quality of Supply – 33% underspent due to delayed construction of a mobile substation site.
- Other Reliability, Safety and Environment – 28% underspent, mainly attributed to a lower spend than planned on distribution earths' refurbishment.

Operational Expenditure

The variation of estimated expenditure versus actual operational spending is presented in Table 88.

Table 88: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2022/23 ($k)	Actual 2022/23 ($k)	Variance
Asset Replacement and Renewal	165	180	9%
Vegetation Management	978	906	(7%)
Routine and Corrective Maintenance and Inspection	1,811	2,833	56%
Service Interruptions and Emergencies	2,186	2,282	4%
Operational Expenditure on Network Assets	**5,139**	**6,211**	**21%**

Maintenance varied from budget due to:

- Asset Replacement and Renewal – 9% overspent, attributed to a higher spends than planned on distribution transformer refurbishment and locks & security renewals.
- Vegetation Management – 7% underspent due to initiating a new contractor.
- Routine and Corrective Maintenance and Inspection – 56% overspent due to higher spend than planned on corrective and routine maintenance, distribution routine inspections and subtransmission line minor maintenance.
- Service Interruptions and Emergencies – 4% overspent due to a larger amount of technical fault work than allowed for.

10.2 2024-34 Update Service Level Performance

Reliability

Table 89 displays the target versus actual reliability performance on the network.

Table 89: Performance against Primary Service Targets

Measure	Class	2022/23 DPP3 Target	2022/23 DPP3 Limit	2022/23 Actual
SAIDI	Planned	140.96	422.89[12]	259.4
	Unplanned	120.02	160.35	143.3
SAIFI	Planned	-	1.9242[11]	0.8674
	Unplanned	-	2.4172	1.7670

[12] Planned SAIDI and SAIFI are assessed at the end of the 5-year period. The figures in the table are annual pro-rata.

The information was prepared consistently with previous disclosures, successive interruptions originating from the same cause were recorded as single interruptions.

The deviations from the planned work and expenditure are similar to 2023-33:

10.1 Progress against Plan

The performance between estimated expenditure and actual expenditure for CAPEX and OPEX is described below.

Capital Expenditure

The variation of estimated expenditure versus actual capital spending is presented in Table 87.

Table 90: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2021/22 ($k)	Actual 2021/22 ($k)	Variance
Consumer Connection	6,622	8,995	36%
System Growth	195	329	69%
Asset Replacement and Renewal	7,013	7,842	12%
Asset Relocations	20	691	3,296%
Quality of Supply	379	506	33%
Legislative and Regulatory	-		-
Other Reliability, Safety and Environment	1,273	1,286	1%
Capital Expenditure on Network Assets	**15,503**	**19,649**	**27%**

Capital works varied from budget due to:

- Customer Connections – 36% overspent due to increased customer driven demand for subdivision reticulation.
- System Growth – 69% overspent due to more than expected new medium voltage cabling works for load growth.
- Asset Replacement and Renewal – 12% overspent mainly due to higher spending on distribution and LV lines' renewal than planned, and to a lesser extent additional spending on relay replacements and pole reinforcement; meanwhile there was lower expenditure on Remote Area Power Supplies because a planned medium-sized site was found to be uneconomic, and expenditure on 33kV line renewal was lower than planned.
- Asset Relocations – Budget overspent by a large margin due to unforeseen works relocating and undergounding power lines for third parties.
- Quality of Supply – 33% overspent attributed to expenditure being above plan for reactive supply quality upgrades.

- Other Reliability, Safety and Environment – 1% overspent, the major variances were higher expenditure on substation NERs & 33kV Transformer Circuit Breakers, somewhat offset by lower spending on earth refurbishments than expected.

Operational Expenditure

The variation of estimated expenditure versus actual operational spending is presented in Table 88.

Table 91: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2021/22 ($k)	Actual 2021/22 ($k)	Variance
Asset Replacement and Renewal	328	209	(36%)
Vegetation Management	810	808	(0%)
Routine and Corrective Maintenance and Inspection	1,986	2,245	13%
Service Interruptions and Emergencies	1,602	2,001	25%
Operational Expenditure on Network Assets	**4,726**	**5,262**	**11%**

Maintenance varied from budget due to:

- Asset Replacement and Renewal – 36% underspent, attributed to a lower spend than planned on distribution refurbishment work resulting from inspections and reactive network chargeable maintenance.
- Vegetation Management – Expenditure met the budget.
- Routine and Corrective Maintenance and Inspection – 13% overspent due to higher spend than planned on distribution routine and corrective maintenance and technical routine and corrective maintenance.
- Service Interruptions and Emergencies – 25% overspent due to a larger amount of distribution faults than allowed for.

10.2 Service Level Performance

Customer Consultation

Key customers are surveyed annually by external consultants. PowerNet, as the de facto service provider, is used as a proxy for the network companies. The main survey findings were:

- Communication – there was a 50/50 split between participants that felt communication was one of PowerNet’s strengths, and those who believed it was an area for improvement.
- Transformer information - participants expressed their desire to have a better understanding about the maintenance needs of transformers, servicing information and how regularly they need to be upgraded.

- Major projects - A few participants confirmed that they would be pursuing major projects in the future. Many have an interest in upgrading their power supply to operate in a more environmentally conscious way, including upgrading to electric boilers and electric machinery due to internal targets and the carbon tax.
- Participants would like to see PowerNet take the initiative and time to fully understand each business and their needs. Ideally, most participants would like to see a PowerNet representative annually to discuss the future needs of the customer's organisation.

Reliability

Table 89 displays the target versus actual reliability performance on the network. For the 2021/22 year, planned SAIDI was below target and unplanned SAIDI was near the mid-point between the target and limit. Unplanned SAIFI was just below the limit while planned SAIFI was significantly below the pro-rata annual limit.

Table 92: Performance against Primary Service Targets

Measure	Class	2021/22 DPP3 Target	2021/22 DPP3 Limit	2021/22 Actual
SAIDI	Planned	140.96	422.89[13]	128.79
	Unplanned	120.02	160.35	141.82
SAIFI	Planned	-	1.9242[11]	0.7772
	Unplanned	-	2.4172	2.3811

The information was prepared consistently with previous disclosures, successive interruptions originating from the same cause were recorded as single interruptions.

Customer Satisfaction

The customer engagement survey conducted by phone provides feedback to understand customer satisfaction regarding a range of aspects around their supply services. Statistics are also recorded for any customer complaints received. Table 93 shows the 2021/22 results against the service level targets.

Table 93: Performance against Secondary Service Targets

Attribute	Measure	Target 2021/22	Actual 2021/22
Customer Satisfaction on Faults	Power restored in a reasonable amount of time {CES}	>50%	68%
	No impact or minor impact of last unplanned outage {CES}	>70%	60%
	Information supplied was satisfactory {CES}	>70%	75%

[13] Planned SAIDI and SAIFI are assessed at the end of the 5-year period. The figures in the table are annual pro-rata.

Attribute	Measure	Target 2021/22	Actual 2021/22
	PowerNet first choice to contact for faults {CES}	>50%	35%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	<20	6
	Number of customers having justified supply quality complaints {IK}	<15	4
Planned Outages	Provide sufficient information {CES}	>75%	92%
	Satisfaction regarding amount of notice {CES}	>75%	99%
	Acceptance of one planned outage every two years lasting four hours on average {CES}	>50%	91%

{ } indicates information source; CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs.

Overall, awareness of PowerNet is high at 77% and has been steadily increasing in the OJV and LLN networks where sources of awareness were mostly through logos on vehicles and PowerNet working on sites.

Network Efficiency

Table 94: Performance against Efficiency Targets

Measure	2021/22 Target	2021/22 Actual
Load factor	> 79%	79%
Loss ratio	< 5.0%	4.4%
Capacity utilisation	> 30%	30%

Capacity utilisation and load factor were on target while loss ratio was better than target.

Load factor reflects the ratio of OJV's average demand to peak demand and averages around 79%. OJV's maximum demand does not coincide with the Lower South Island coincidental demand, therefore Transpower's Transmission Pricing Methodology does not drive the control of peak demand in OJV, thus having a negative impact on load factor.

Reported losses tend to vary slightly from year to year, more than can be explained by changes in operation and network assets. This variation can mostly be attributed to the retailer accrual process. Therefore, a longer-term average is more likely to be indicative of actual loss ratio and the longer term average is slightly over 4%.

While it is desirable to have a capacity utilisation factor as high as possible, standardisation of transformer sizing, allowance for growth and the unpredictable consumption patterns of customers mean there is a practical and economic limit to how much this factor can be improved. OJV's capacity utilisation compares very well with other predominantly rural distribution businesses.

Financial Efficiency

Table 95: Performance against Financial Targets

Measure	2021/22 Target	2021/22 Actual
Network OPEX/ICP	$326	$283
Network OPEX/km	$1,138	$1,135
Network OPEX/MVA	$26,212	$22,850
Non-Network OPEX/ICP	$170	$189
Non-Network OPEX/km	$589	$755
Non-Network OPEX/MVA	$13,696	$15,208

OJV's network financial efficiency results were better than planned for 2021/22. The non-network OPEX financial efficiency results were also higher than planned.

10.3 AMMAT Performance

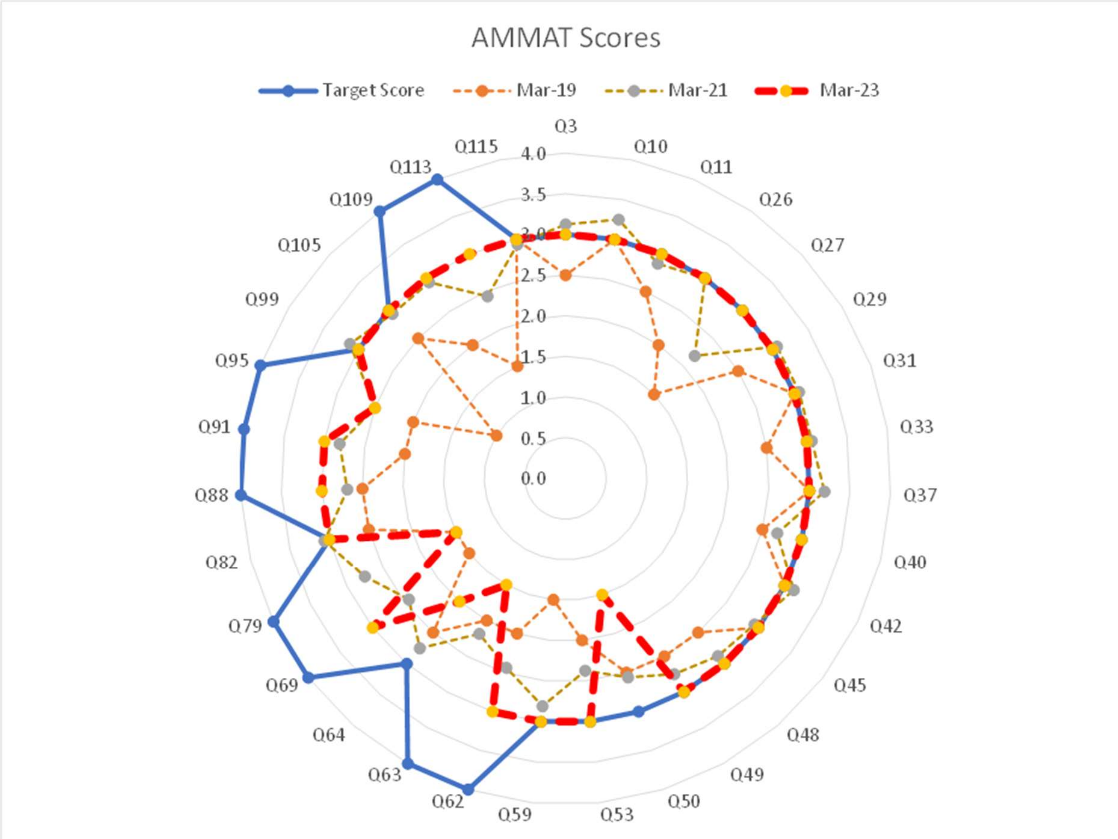
PowerNet understands the foundations of good asset management practice and endeavours to comply with international best practice as embodied in the ISO5500X suite of standards (a management system for Asset Management). In addition, the original PAS 55 principles are adopted (as this is the measurement standard still utilised by ComCom). These foundations are applied in OJV.

The AMMAT (Asset Management Maturity Assessment Tool) is based on a selection of questions based on PAS-55. It is intended to prompt consideration of performance against a number of facets of good asset management practice. Each question can be scored from '0' to '4' and each question has a series of answers to describe what is required to achieve each scoring level. Annexure 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

PowerNet commissioned Utility Consultants to do an AMMAT assessment for this AMP. The focus was on the changes that had occurred since the 2021 assessment. In scoring OJV's asset management practice against the maturity tool, scores from '1.5' to '3.0' with an average score of '2.8' were achieved as shown in Figure 55. All the areas covered in the questionnaire are not of equal importance to an EDB, so target scores were set for each area. These target scores are indicated by the blue curve.

The red curve shows the result of this assessment.

Figure 55: Asset Management Maturity Assessment Scores



10.4 Gap Analysis and Planned Improvements

Asset Management Maturity

For a distribution company of OJV's size a score of between '2' and '3' for many of the asset management functions is considered appropriate. However as PowerNet provides OJV's asset management services as well as providing this service across other networks, OJV believes that some improvements are realisable and appropriate. The audit shows that OJV has maturity improvement in most areas, except for the following:

Q50	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?
Q63	Information management	How does the organization 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?
Q79	Use and maintenance of asset risk information	How does the organization ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?

Q50 relates to both field and office staff. The competency requirements for field staff are well documented and managed, more so than that of office staff. Although we are satisfied that all office staff have an appropriate level of competency, documentation to prove this is not as readily available as for field staff. This is being addressed by the introduction of the Learning Management System which will make this information available to authorised staff.

Q63 relating to data is being progressively addressed through the upgrade of the Asset Management Information Systems. In addition, a Data Management Steering Group has been established to address the issue of data and to ensure that data is treated as a critical asset with its own lifecycle activities.

Q79 addresses the use of asset risk information to provide input into the identification of adequate resources and training and competency needs. This is currently done indirectly through the AWPs, but as better asset health data becomes available to inform our risk analysis, a more direct link between risk and resources will be established.

Other initiatives for improvement that are in progress or have been completed are.

- Asset Fleet Plans were being developed that will allow improved management of assets over their full life cycle. These plans are incorporated into the Asset Management Information System.
- The stage gate process for managing major projects has been adapted and will be introduced to improve capital and maintenance project implementation. This includes standardised work packs and unit rates for most jobs.
- The PowerNet organisational structure has been further refined to enhance the ability to deliver the OJV asset management objectives.
- A Data Strategy and an Information System Strategy were developed and are being implemented. Key to these strategies is recognising and agreeing that the computerised asset management information system (MAXIMO) will be the single source of truth around assets. Further implemented improvements to the system are:
  - Including a Risk Management module into the system.
  - Expanding work scheduling to more systematically and efficiently schedule and track asset maintenance activities to additional asset types.
  - Developing more compatible units to allow standardisation common asset types including cost by materials and labour to enable efficient costing and scheduling of future work.
  - Integration of OJV’s financial management system to efficiently track costs supporting compatible units and understanding whole of lifecycle costs for these assets.

  - Rolling out field devices to operational staff that will allow the direct capturing of data from the field. This also includes automating the risk management framework used in works by field staff.

- A new drawing management system that allowing access to drawings from the field.
- A system to keep everybody abreast of legal, regulatory and statutory requirements.

ISO 55001 Asset Management System implementation

PowerNet's Asset Management System is in the process of certification to ISO 5001. Indications after the two round of audits are that our system is compliant and that we will be certified in April.

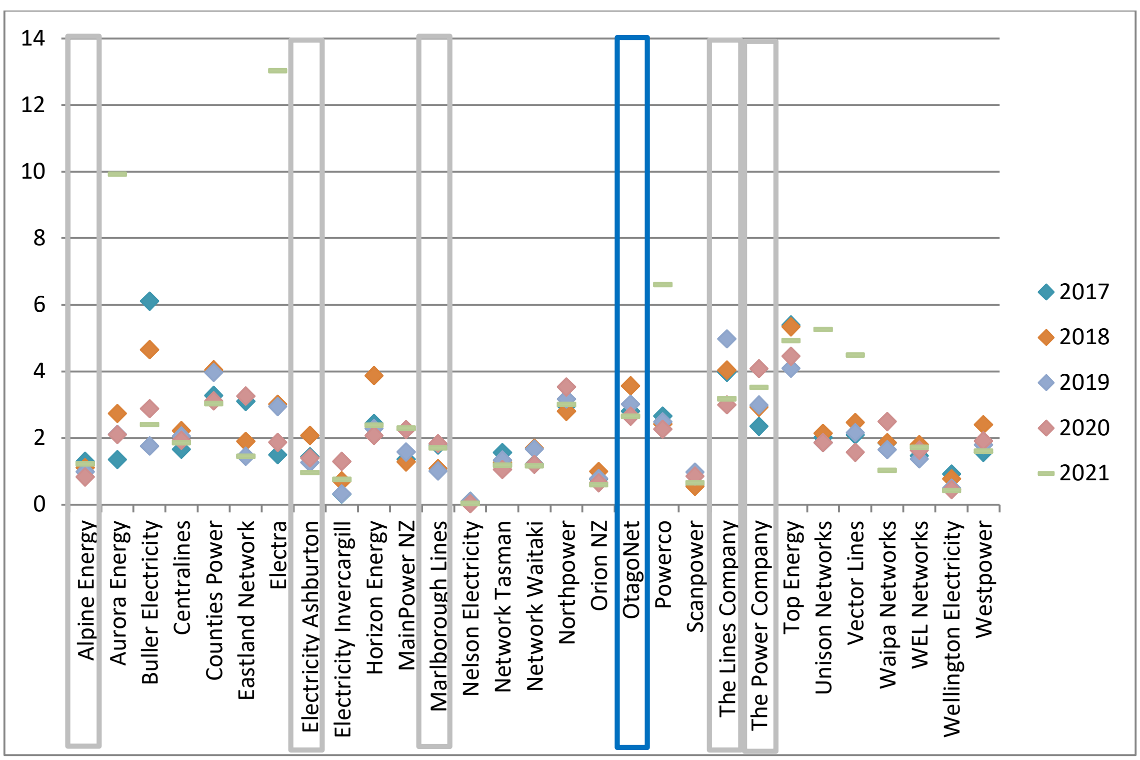
10.5 Benchmarking

Benchmarking against other local distribution networks assist with the identification of potential improvements in the current service levels that OJV offers. To aid in comparison, other predominantly rural lines companies of a similar network size (-50% to +100%) have been highlighted in grey boxes.

SAIFI

EDB reliability results as published by ComCom since 2017 show OJV is about average compared to peer networks in minimising the number of supply interruptions to customers.

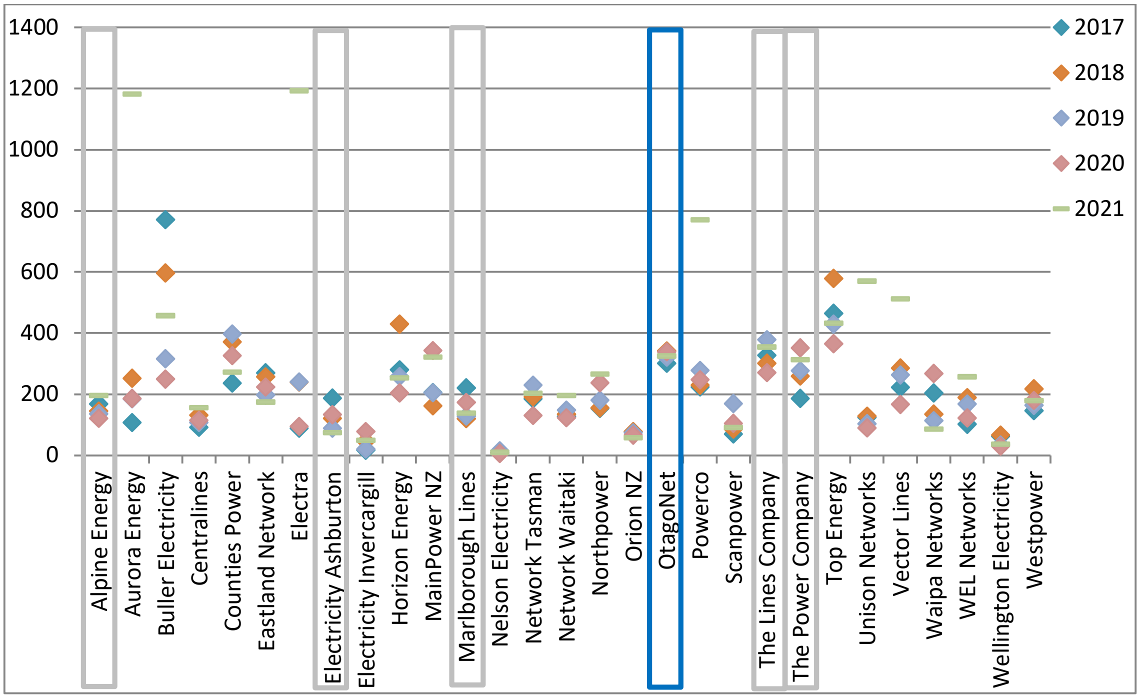
Figure 56: SAIFI Benchmarking



SAIDI

EDB reliability results since 2017 show that the amount of time without supply experienced by OJV's customers is slightly higher than average for other predominantly rural lines companies. This is explained by the sparsity of the network (increased response times).

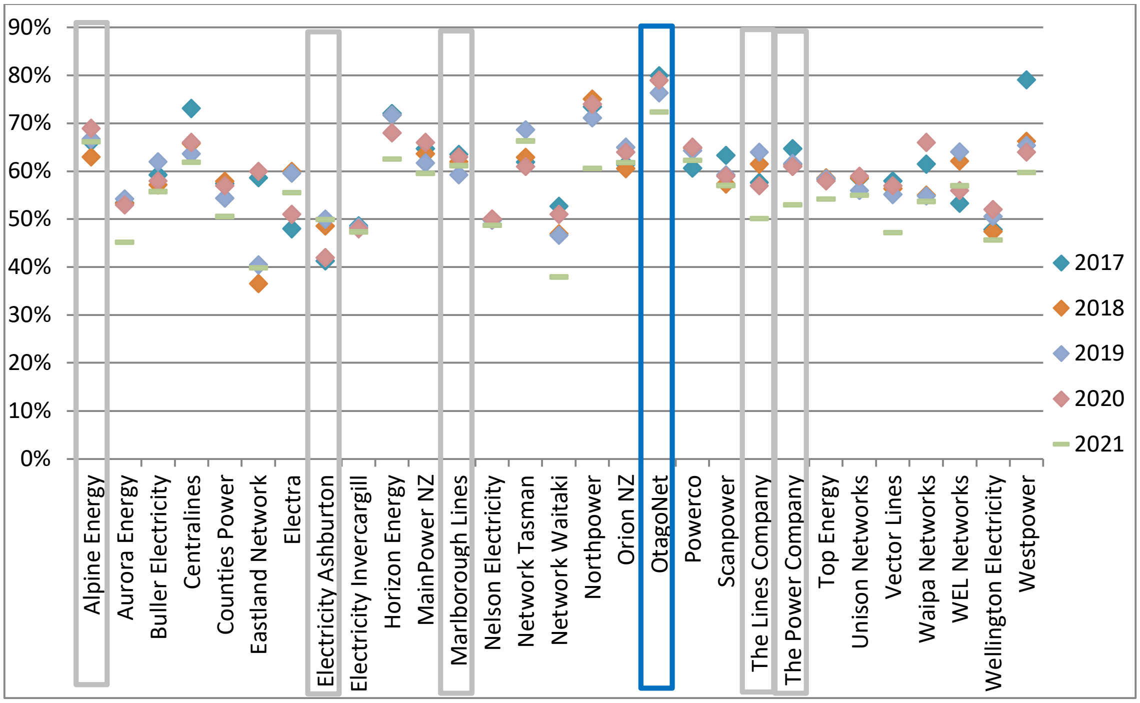
Figure 57: SAIDI Benchmarking



Load Factor

Comparison with other networks shows that OJV's load factor is relatively high, due in part to the high industrial and irrigation component of the load. Load factor is expected to remain at current levels in the medium term.

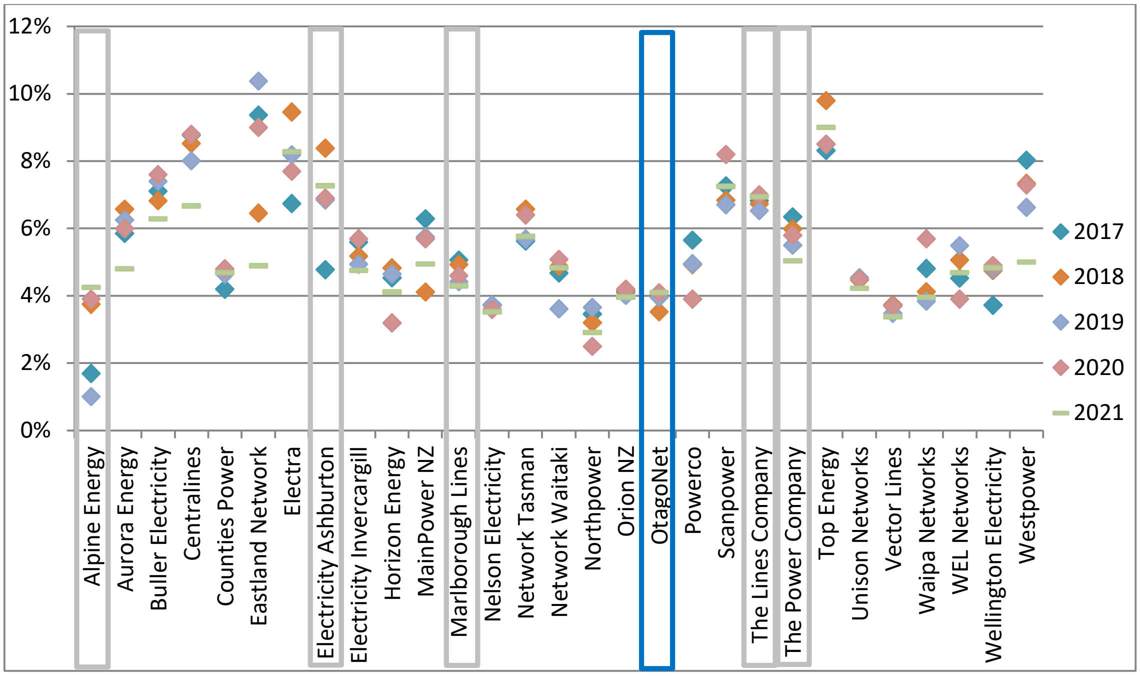
Figure 58: Load Factor Comparison



Loss Ratio

Energy efficiency is getting increased attention, but in general it is uneconomical to improve efficiency of primary assets in order to minimise losses. The financial incentive for a network company to reduce losses is minimal, as losses are paid for by retailers. The exception is when the losses lead to other technical issues such as poor voltage or an exceeding the current rating of equipment. Upgrading network equipment as growth occurs will maintain losses at present levels.

Figure 59: Loss Ratio Comparison



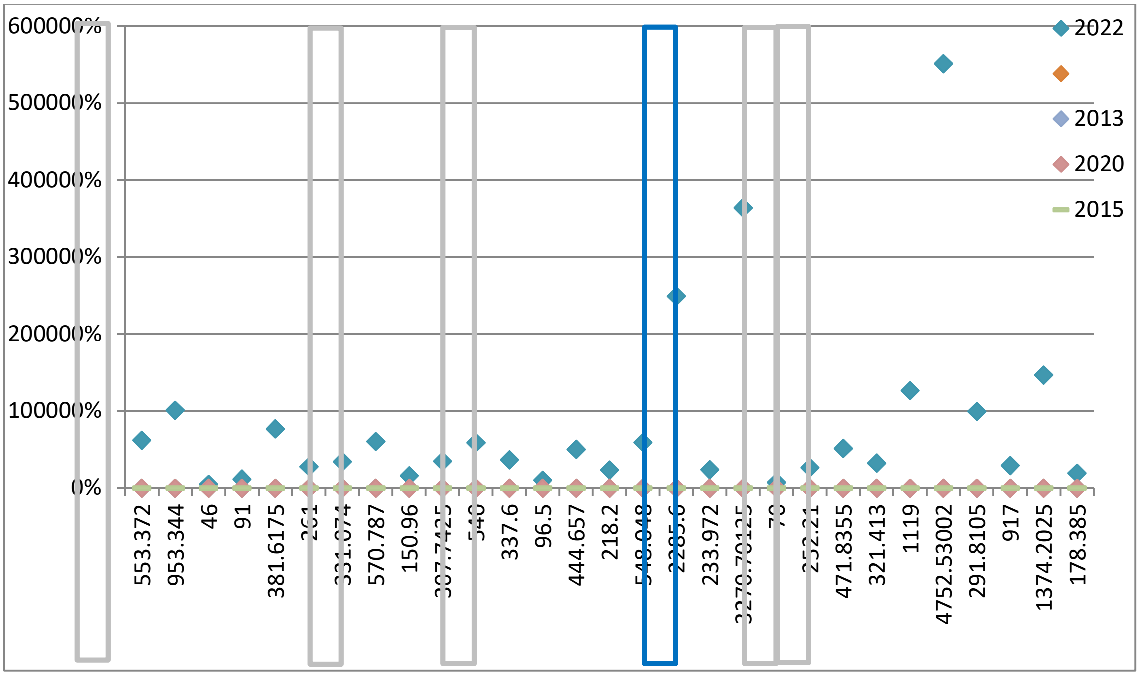
Comparison with other network companies shows OJV's network is among the more efficient. OJV can expect a long term average in the range of 4-5% to be maintained however year to year results can vary due to retailer estimations and the target has therefore been set at the higher end of the range.

Capacity Utilisation

Capacity utilisation on the network can be improved through optimisation of transformer sizes and numbers. However, there is often a trade-off between utilisation and standardisation. A larger, standard size transformer will in most cases be less expensive that a smaller, non-standard transformer sized to improve utilisation. It is generally more cost effective to replace overloaded transformers with appropriately sized standard units than to build bespoke transformers to increase utilisation.

Comparing OJV's capacity utilisation with other local EDBs illustrates that OJV has an appropriate capacity utilisation factor for a predominantly rural network, therefore no strategies for improvement are warranted.

Figure 60: Capacity Utilisation Comparison



Financial Efficiency

Financial efficiency ratios do not raise any concerns when benchmarked against industry peers. These comparisons are presented in the following figures. These figures show:

- Operational expenditure per ICP is overall relatively high, but still comparable to peers.
- Operational expenditure per km of network length is relatively low.
- Operational expenditure per MVA of distribution transformer capacity is relatively high, but still comparable to peers.
- Non-network Operational expenditure measures are relatively low.

Figure 61: $OPEX/ICP Benchmarking

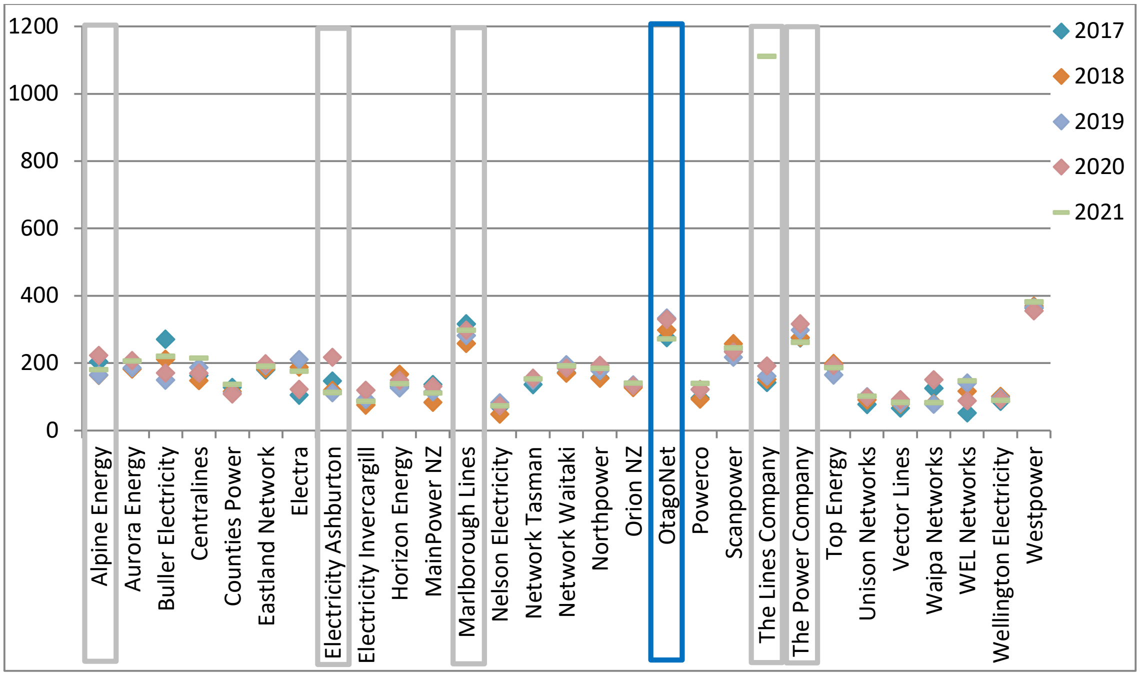


Figure 62: $OPEX/km Benchmarking

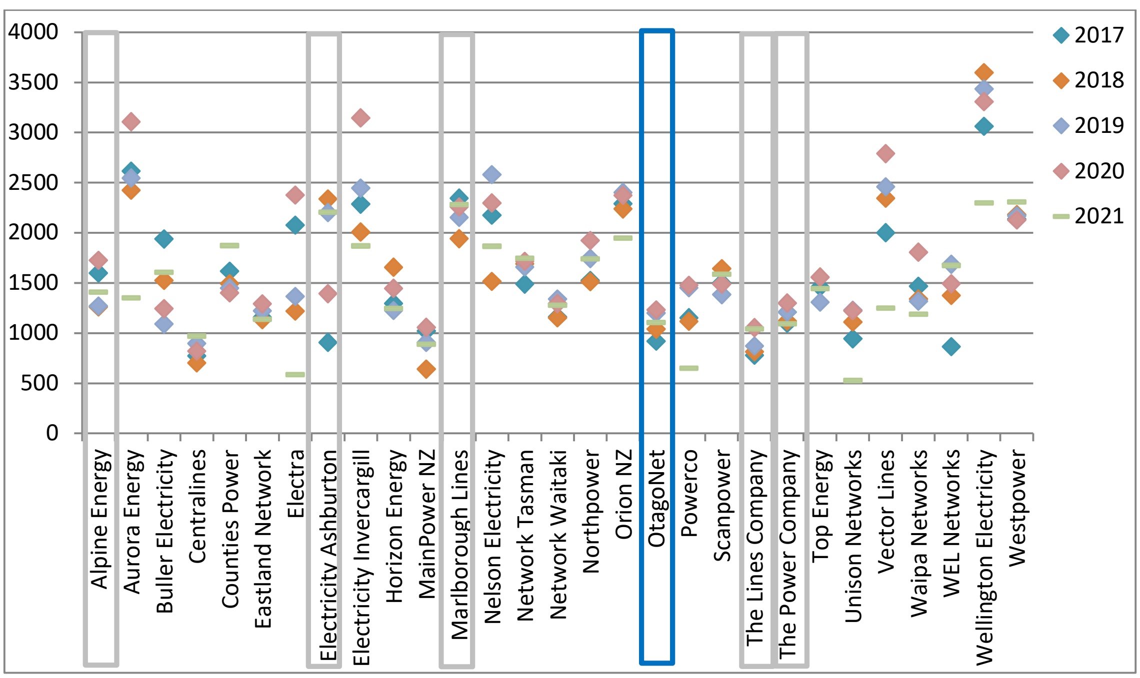


Figure 63: $OPEX/MVA Benchmarking

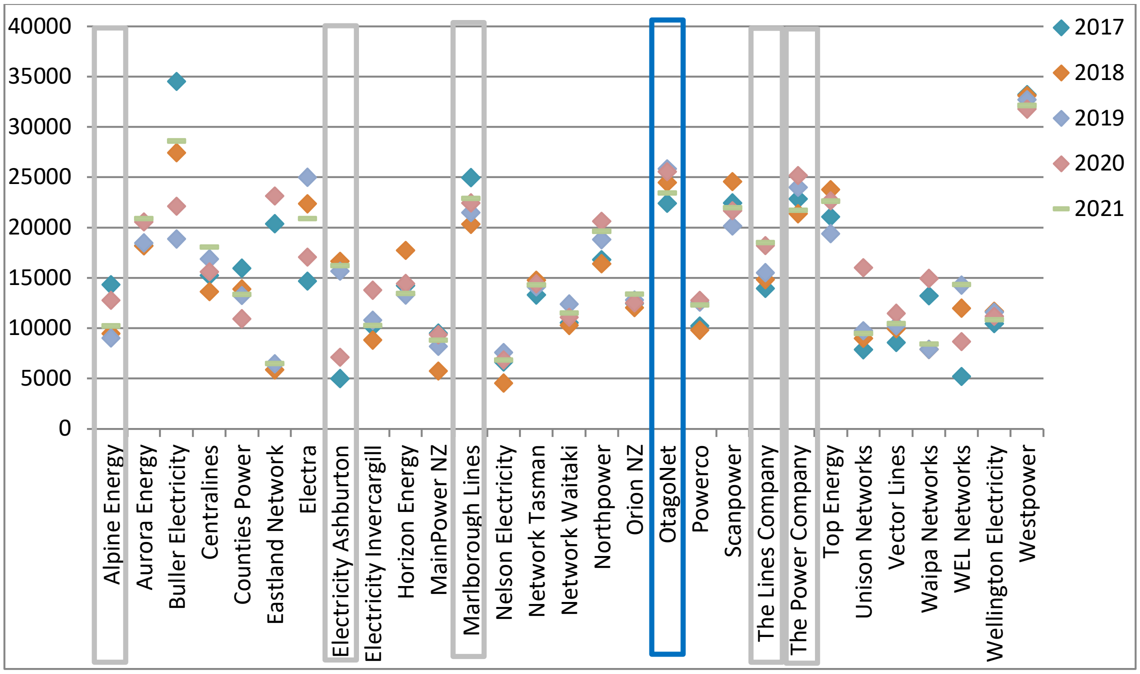


Figure 64: Non-Network $OPEX/ICP Benchmarking

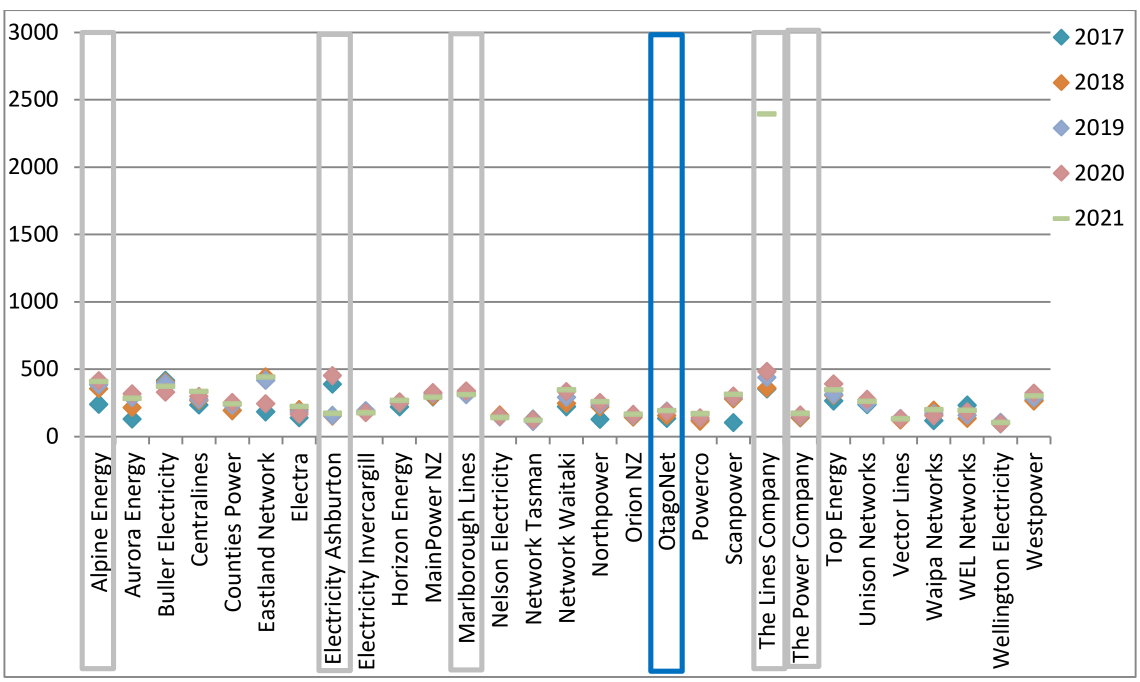


Figure 65: Non-Network $OPEX/km Benchmarking

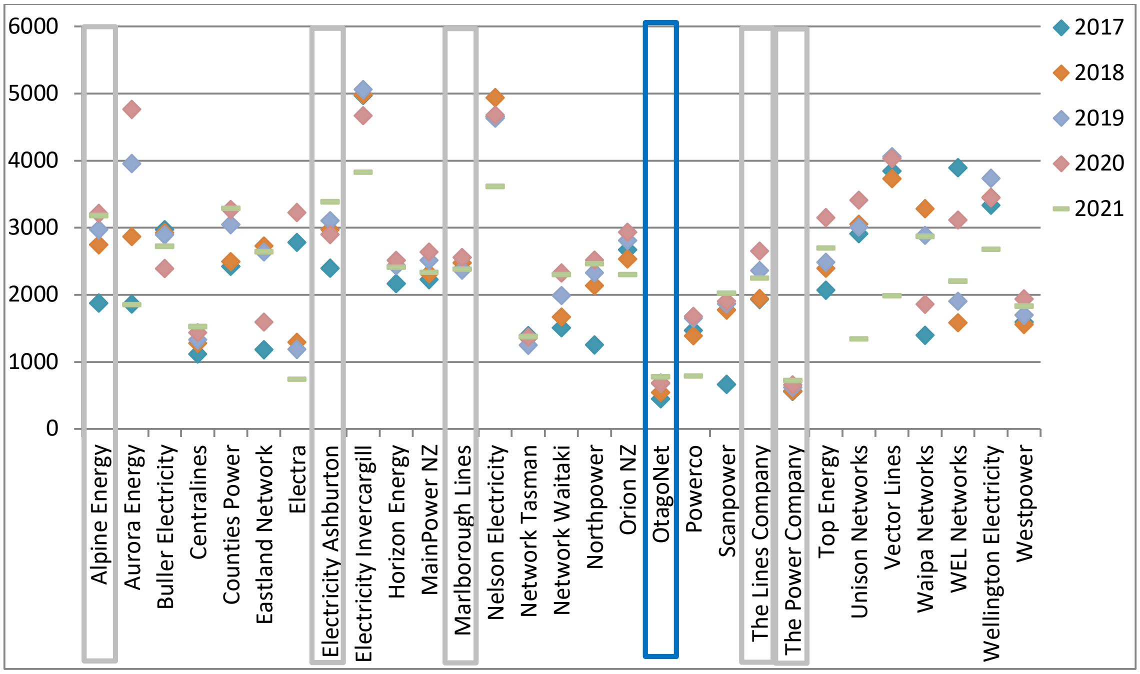
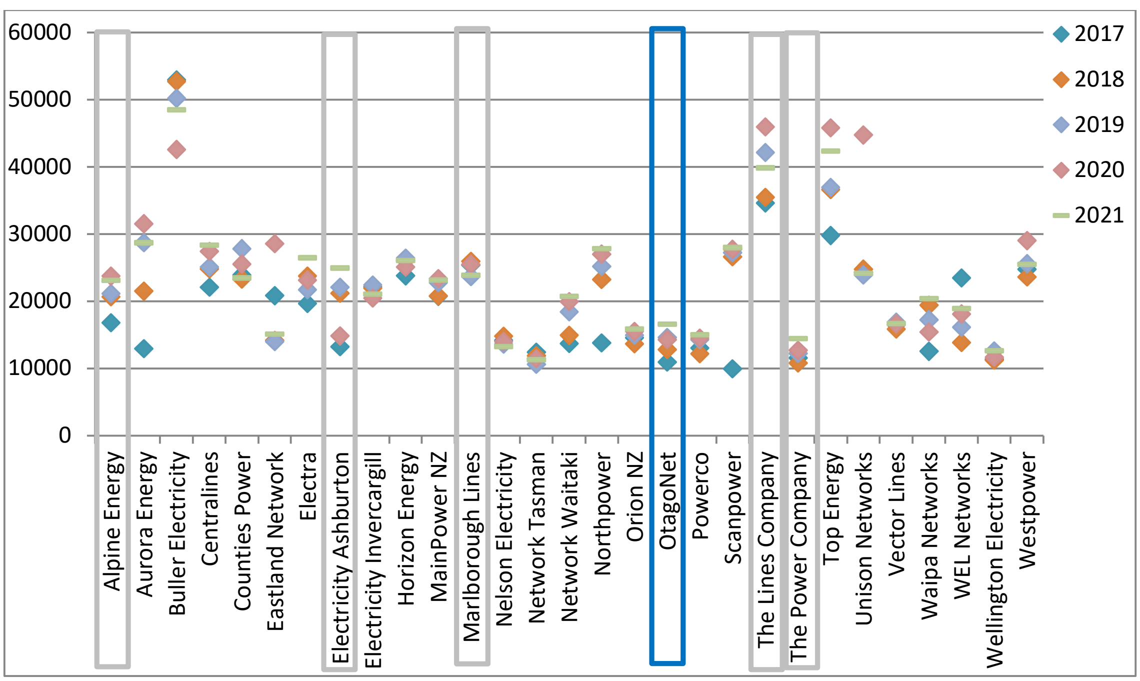


Figure 66: Non-Network $OPEX/MVA Benchmarking



Annexure 3 – Disclosure Schedules

Schedule 11a. – Capital Expenditure Forecast

Company Name: **OtagoNet Joint Venture**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	8,569	5,413	7,002	7,471	7,066	6,986	7,145	7,295	7,414	7,562	7,713
11		System growth	203	2,397	2,535	526	1,482	2,955	16,612	2,758	1,498	1,528	1,559
12		Asset replacement and renewal	11,105	8,585	11,440	22,958	22,209	22,805	12,039	18,836	17,520	18,241	18,605
13		Asset relocations	338	1,471	39	40	41	42	43	44	45	45	46
14		Reliability, safety and environment:											
15		Quality of supply	761	13	1,839	529	47	389	397	6,430	6,196	5,950	6,032
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,040	802	1,372	1,150	2,393	2,395	828	551	562	573	585
18		**Total reliability, safety and environment**	1,801	815	3,211	1,679	2,440	2,784	1,225	6,981	6,758	6,523	6,617
19		**Expenditure on network assets**	22,016	18,680	24,227	32,674	33,238	35,572	37,064	35,914	33,235	33,899	34,540
20		Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
21		**Expenditure on assets**	22,016	18,680	24,227	32,674	33,238	35,572	37,064	35,914	33,235	33,899	34,540
22													
23	plus	Cost of financing											
24	less	Value of capital contributions	1,570	2,465	1,146	898	916	935	953	972	992	1,012	1,032
25	plus	Value of vested assets											
26													
27		**Capital expenditure forecast**	20,446	16,215	23,082	31,776	32,322	34,637	36,111	34,942	32,243	32,888	33,509
28													
29		Assets commissioned	20,895	15,224	25,735	31,363	31,900	33,064	38,248	35,581	32,285	32,945	33,906

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31												
32		**$000 (in constant prices)**										
33	Consumer connection	8,569	5,413	6,831	7,132	6,613	6,410	6,428	6,434	6,410	6,410	6,410
34	System growth	203	2,397	2,473	502	1,387	2,712	14,944	2,432	1,295	1,295	1,295
35	Asset replacement and renewal	11,105	8,585	11,161	21,916	20,785	20,924	10,830	16,612	15,148	15,462	15,462
36	Asset relocations	338	1,471	38	38	38	38	38	38	38	38	38
37	Reliability, safety and environment:											
38	Quality of supply	761	13	1,794	505	44	357	357	5,671	5,357	5,044	5,013
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,040	802	1,338	1,097	2,239	2,197	745	486	486	486	486
41	**Total reliability, safety and environment**	1,801	815	3,133	1,602	2,283	2,554	1,102	6,157	5,843	5,530	5,499
42	**Expenditure on network assets**	22,016	18,680	23,636	31,191	31,107	32,639	33,341	31,673	28,735	28,735	28,705
43	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	22,016	18,680	23,636	31,191	31,107	32,639	33,341	31,673	28,735	28,735	28,705
45												
46	**Subcomponents of expenditure on assets (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
47	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
48	Overhead to underground conversion	200	1,433	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	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
50	Cybersecurity (Commission only)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
51												

Schedule 11a. – Capital Expenditure Forecast (continued)

Difference between nominal and constant price forecasts

$000	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	-	-	171	339	453	576	718	861	1,004	1,152	1,303
System growth	-	-	62	24	95	244	1,669	326	203	233	263
Asset replacement and renewal	-	-	279	1,042	1,424	1,880	1,209	2,224	2,372	2,779	3,143
Asset relocations	-	-	1	2	3	3	4	5	6	7	8
Reliability, safety and environment:											
Quality of supply	-	-	45	24	3	32	40	759	839	906	1,019
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	33	52	153	197	83	65	76	87	99
Total reliability, safety and environment	-	-	78	76	156	230	123	824	915	994	1,118
Expenditure on network assets	-	-	591	1,483	2,131	2,933	3,723	4,241	4,499	5,164	5,836
Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	-	-	591	1,483	2,131	2,933	3,723	4,241	4,499	5,164	5,836

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

*Consumer types defined by EDB** / $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Major New Connections Projects	5,959	3,788	5,341	5,642	5,123	4,920
Other New Connections	2,610	1,625	1,490	1,490	1,490	1,490
**include additional rows if needed*						
Consumer connection expenditure	8,569	5,413	6,831	7,132	6,613	6,410
less Capital contributions funding consumer connection	1,570	857	1,118	857	857	857
Consumer connection less capital contributions	7,000	4,555	5,714	6,275	5,756	5,552

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	9	-	-	-	115	-
Zone substations	9	1,505	1,019	-	115	1,555
Distribution and LV lines	50	6	339	6	6	6
Distribution and LV cables	136	885	959	496	1,151	1,151
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	157	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	203	2,397	2,473	502	1,387	2,712
less Capital contributions funding system growth						
System growth less capital contributions	203	2,397	2,473	502	1,387	2,712

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	673	2,189	2,861	2,751	2,276	2,786
Zone substations	2,953	547	2,393	11,931	11,207	11,342
Distribution and LV lines	6,836	5,215	5,234	5,663	5,770	5,231
Distribution and LV cables	28	13	13	13	13	13
Distribution substations and transformers	246	212	393	1,145	1,145	1,145
Distribution switchgear	349	409	245	297	297	297
Other network assets	21	-	22	117	77	110
Asset replacement and renewal expenditure	11,105	8,585	11,161	21,916	20,785	20,924
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	11,105	8,585	11,161	21,916	20,785	20,924

Schedule 11a. – Capital Expenditure Forecast (continued)

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	Network Chargeable Capital	161	38	38	38	38	38
	Milton Main Street Undergrounding	177	1,433	-	-	-	-
	**include additional rows if needed*						
	All other project or programmes - asset relocations						
	Asset relocations expenditure	338	1,471	38	38	38	38
less	Capital contributions funding asset relocations		1,608				
	Asset relocations less capital contributions	338	(136)	38	38	38	38

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	Finegand 33kV smart network automation	323	-	1,434	-	-	-
	Network Improvement Projects	15	-	195	148	-	
	Mobile Substation site made ready	220	-	-	313	-	313
	Northlake to Clearview Link Cable	-	-	152	-	-	-
	**include additional rows if needed*						
	All other projects or programmes - quality of supply	203	13	13	44	44	44
	Quality of supply expenditure	761	13	1,794	505	44	357
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	761	13	1,794	505	44	357

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	**include additional rows if needed*						
	All other projects or programmes - legislative and regulatory						
	Legislative and regulatory expenditure	-	-	-	-	-	-
less	Capital contributions funding legislative and regulatory						
	Legislative and regulatory less capital contributions	-	-	-	-	-	-

Schedule 11a. – Capital Expenditure Forecast (continued)

11a(viii): Other Reliability, Safety and Environment

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
*Project or programme**	$000 (in constant prices)					
Substation NERs and 33kV Transformer Circuit Breakers	158	100	271	-	-	-
Communications Upgrade	-	-	-	120	1,266	1,266
Replacement of OH Structures with Ground Mounted	44	-	248	248	248	248
Earth refurbishment from earth testing, incl. SWER	647	701	759	729	541	541
Transformer Oil Containment & Seismic Strengthening	-	-	-	-	185	142
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	192	-	60	-	-	-
Other reliability, safety and environment expenditure	1,040	802	1,338	1,097	2,239	2,197
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	1,040	802	1,338	1,097	2,239	2,197

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	-	-	-	-	-	-
Atypical expenditure						
*Project or programme**						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	-	-	-	-	-	-

Schedule 11b. – Operational Expenditure Forecast

Company Name: **OtagoNet Joint Venture**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,188	2,208	2,264	2,313	2,360	2,407	2,455	2,504	2,554	2,605	2,657
11	Vegetation management	1,213	1,265	1,114	1,139	1,162	1,185	1,209	1,233	1,257	1,283	1,308
12	Routine and corrective maintenance and inspection	2,352	3,020	3,159	3,504	3,808	3,511	3,654	3,811	3,439	4,214	4,289
13	Asset replacement and renewal	248	244	183	187	191	194	198	202	206	211	215
14	**Network Opex**	6,001	6,737	6,720	7,143	7,520	7,297	7,516	7,750	7,457	8,312	8,469
15	System operations and network support	2,006	1,220	1,734	2,017	2,057	2,099	2,141	2,183	2,227	2,272	2,317
16	Business support	1,764	2,907	3,060	3,184	3,248	3,313	3,379	3,446	3,515	3,586	3,657
17	**Non-network opex**	3,771	4,127	4,794	5,201	5,305	5,411	5,519	5,630	5,742	5,857	5,974
18	**Operational expenditure**	9,771	10,864	11,514	12,344	12,825	12,708	13,035	13,380	13,199	14,169	14,444
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,188	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208	2,208
23	Vegetation management	1,213	1,265	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087
24	Routine and corrective maintenance and inspection	2,352	3,020	3,082	3,345	3,564	3,221	3,287	3,361	2,973	3,572	3,564
25	Asset replacement and renewal	248	244	178	178	178	178	178	178	178	178	178
26	**Network Opex**	6,001	6,737	6,556	6,819	7,038	6,695	6,761	6,835	6,447	7,046	7,038
27	System operations and network support	2,006	1,220	1,692	1,925	1,925	1,925	1,925	1,925	1,925	1,925	1,925
28	Business support	1,764	2,907	2,986	3,039	3,039	3,039	3,039	3,039	3,039	3,039	3,039
29	**Non-network opex**	3,771	4,127	4,677	4,965	4,965	4,965	4,965	4,965	4,965	4,965	4,965
30	**Operational expenditure**	9,771	10,864	11,233	11,784	12,003	11,660	11,726	11,800	11,412	12,011	12,003
31	**Subcomponents of operational expenditure (where known)** **EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
32	Energy efficiency and demand side management, reduction of											
33	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	308	679	949	949	949	949	949	949	949	949	949
37	Cybersecurity (Commission only)	52	52	52	52	52	52	52	52	52	52	52
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												
40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	-	55	105	151	198	247	296	346	397	449
44	Vegetation management	-	-	27	52	74	98	121	146	170	195	221
45	Routine and corrective maintenance and inspection	-	-	77	159	244	290	367	450	466	642	725
46	Asset replacement and renewal	-	-	4	8	12	16	20	24	28	32	36
47	**Network Opex**	-	-	164	324	482	602	755	915	1,009	1,266	1,431
48	System operations and network support	-	-	42	92	132	173	215	258	301	346	391
49	Business support	-	-	75	145	208	273	339	407	476	546	618
50	**Non-network opex**	-	-	117	236	340	446	554	665	777	892	1,009
51	**Operational expenditure**	-	-	281	560	822	1,048	1,309	1,580	1,787	2,158	2,440
52												
53	**Commentary on options and considerations made in the assessment of forecast expenditure**											
54	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*											
55												

Schedule 12a. – Asset Condition

Company Name: **OtagoNet Joint Venture**
AMP Planning Period: **1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.69%	9.88%	45.13%	41.87%	2.43%	3	0.51%
11	All	Overhead Line	Wood poles	No.	16.16%	11.12%	61.09%	1.99%	3.83%	5.81%	3	9.14%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.13%	28.16%	27.67%	21.83%	13.14%	8.07%	2	8.80%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	2.74%	6.85%	82.19%	8.22%	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	N/A	-
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.	-	11.11%	46.67%	20.00%	22.22%	-	2	11.11%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	88.89%	-	11.11%	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	2.08%	79.17%	2.08%	16.67%	3	6.25%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	4.84%	64.52%	2.69%	27.96%	3	3.76%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	100.00%	2	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	100.00%	-	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	4.65%	-	23.26%	72.09%	-	-	3	6.98%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	7.81%	21.88%	59.38%	1.56%	9.38%	-	3	31.25%
35												

Schedule 12a. – Asset Condition (Continued)

Row	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	34.09%	65.91%	-	-	4	11.36%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.15%	8.28%	19.66%	35.51%	34.35%	2.05%	2	6.77%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	17.47%	22.87%	34.75%	24.47%	0.44%	2	13.42%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	1.74%	2.76%	12.35%	72.38%	10.77%	1	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	5.26%	78.95%	15.79%	1	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	90.32%	-	9.68%	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	4.95%	10.26%	51.65%	6.23%	26.92%	3	6.04%
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.	-	-	5.30%	31.82%	47.73%	15.15%	1	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.05%	0.27%	3.93%	37.42%	2.34%	55.99%	3	4.88%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.56%	3.94%	49.30%	8.73%	37.46%	3	0.56%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	100.00%	-	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	0.17%	44.57%	20.81%	5.17%	15.93%	13.35%	1	7.12%
56	LV	LV Cable	LV UG Cable	km	0.08%	1.26%	3.71%	4.07%	77.66%	13.22%	1	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	0.43%	0.76%	0.65%	39.08%	59.08%	1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	56.63%	3.16%	1.26%	3.43%	35.52%	1	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	32.94%	8.63%	18.43%	38.43%	1.57%	-	4	40.78%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	100.00%	-	-	-	-	1	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	20.00%	-	20.00%	20.00%	40.00%	-	1	-
63	All	Load Control	Relays	No.	-	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Schedule 12b. – Capacity Forecast

Company Name	**OtagoNet Joint Venture**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Charlotte Street (Balclutha)	5.4	5	N-1	1	109%	5	110%	Transformer	Over N-1 but load transfer available.
10	Clarks	0.3	-	N		-	-	-	No constraint within +5 years	
11	Clinton	2.1	-	N		-	-	-	No constraint within +5 years	
12	Clydevale	3.9	-	N		-	-	-	No constraint within +5 years	
13	Deepdell	0.1	-	N		-	-	-	No constraint within +5 years	
14	Elderlee Street (Milton)	4.5	5	N-1		90%	5	91%	No constraint within +5 years	
15	Finegand	1.1	-	N		-	-	-	No constraint within +5 years	
16	Glenore	0.6	-	N		-	-	-	No constraint within +5 years	
17	Golden Point	3.0	-	N		-	-	-	No constraint within +5 years	Load transferred to Macraes end 2013, now standby substation.
18	Greenfield	2.5	-	N		-	-	-	No constraint within +5 years	
19	Hindon	0.2	-	N		-	-	-	No constraint within +5 years	
20	Hyde	0.9	-	N		-	-	-	No constraint within +5 years	
21	Kaitangata	1.5	-	N		-	-	-	No constraint within +5 years	
22	Lawrence	1.3	-	N		-	-	-	No constraint within +5 years	
23	Linnburn	0.8	-	N		-	-	-	Other	Temporary sub to be made obsolete by Patearoa sub expansion in 2025/26.
24	Merton	2.6	2.5	N-1		104%	-	-	No constraint within +5 years	Near N-1 capacity, replacement Quarry Road substation (N security) planned in 2026/27.
25	Middlemarch	0.8	-	N		-	-	-	No constraint within +5 years	
26	Milburn	2.3	-	N		-	-	-	No constraint within +5 years	Monitoring growth.
11	North Balclutha	2.7	-	N	1	-	-	-	No constraint within +5 years	
12	Oturehua	0.2	-	N		-	-	-	No constraint within +5 years	
13	Owaka	1.6	-	N		-	-	-	No constraint within +5 years	
14	Paerau	0.3	-	N		-	-	-	No constraint within +5 years	
15	Paerau Powerhouse	11.9	15	N-1		79%	15	80%	No constraint within +5 years	Fixed generation capacity.
16	Palmerston	2.2	2.5	N-1		88%	2.5	89%	No constraint within +5 years	
17	Patearoa	2.3	-	N		-	-	-	Transformer	Transformer upgrade planned in 2025/26.
18	Port Molyneux	0.7	-	N		-	-	-	No constraint within +5 years	
20	Pukeawa	0.5	-	N		-	-	-	No constraint within +5 years	
21	Ranfurly 33/11kV	2.1	-	N		-	2.5	87%	No constraint within +5 years	
22	Ranfurly 66/33kV	27.0	25	N-1		108%	25	108%	Transformer	Monitoring growth, one large industrial customer. Transformers' peak load is generally offset by embedded generation.
23	Remarkables (Frankton)	11.1	12.5	N-1		89%	12.5	113%	Transformer	Monitoring growth. A new (additional) zone substation in the area will relieve the loading on Remarkables substation from 2030/31.
24	Stirling	4.0	-	N		-	-	-	No constraint within +5 years	Monitoring growth.
25	Waihola	1.2	-	N		-	-	-	No constraint within +5 years	Monitoring growth.
26	Waipiata	1.3	-	N		-	-	-	No constraint within +5 years	
27	Waitati	1.7	-	N		-	-	-	No constraint within +5 years	
28	Wedderburn	0.2	-	N		-	-	-	No constraint within +5 years	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c. – Demand Forecast

Company Name	**OtagoNet Joint Venture**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		Consumer Connections <=20 kVA	709	677	677	677	677	677
13		Consumer Connections 21-99 kVA	30	28	28	28	28	28
14		Consumer Connections >=100 kVA	6	5	5	5	5	5
15								
16								
17		**Connections total**	745	710	710	710	710	710
18		**include additional rows if needed*						
19								
20								
21								
22		**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23		Number of connections made in year	77	81	85	88	92	96
24		Capacity of distributed generation installed in year (MVA)	0.52	0.54	0.57	0.59	0.62	0.64
25		**12c(ii) System Demand**						
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**						
28		GXP demand	59	60	61	62	63	64
29	*plus*	Distributed generation output at HV and above	10	10	10	10	10	10
30		**Maximum coincident system demand**	70	71	72	73	73	74
31	*less*	Net transfers to (from) other EDBs at HV and above	(1)	(1)	(1)	(1)	(1)	(1)
32		**Demand on system for supply to consumers' connection points**	70	71	72	73	74	75
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	383	388	394	400	406	412
35	*less*	Electricity exports to GXPs	-	-	-	-	-	-
36	*plus*	Electricity supplied from distributed generation	159	160	161	162	162	163
37	*less*	Net electricity supplied to (from) other EDBs	(6)	(6)	(6)	(6)	(6)	(6)
38		**Electricity entering system for supply to ICPs**	548	554	561	568	575	582
39	*less*	Total energy delivered to ICPs	526	533	539	546	552	559
40		**Losses**	21	22	22	22	22	23
41								
42		**Load factor**	89%	89%	89%	89%	88%	88%
43		**Loss ratio**	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
44								

Schedule 12d. – Reliability Forecast – OtagoNet Network

Company Name	OtagoNet Joint Venture
AMP Planning Period	1 April 2024 – 31 March 2034
Network / Sub-network Name	OtagoNet Network

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	329.5	267.4	267.4	267.4	267.4	267.4
12	Class C (unplanned interruptions on the network)	233.7	197.7	195.1	192.4	189.9	187.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.11	0.89	0.89	0.89	0.89	0.89
15	Class C (unplanned interruptions on the network)	2.08	2.05	2.02	1.99	1.97	1.94

Schedule 12d. – Reliability Forecast – Otago Sub-Network

Company Name	**OtagoNet Joint Venture**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	394.9	276.5	276.5	276.5	276.5	276.5
12	Class C (unplanned interruptions on the network)	290.1	231.2	230.2	229.3	228.3	227.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.32	1.00	1.00	1.00	1.00	1.00
15	Class C (unplanned interruptions on the network)	2.86	2.41	2.40	2.39	2.38	2.37

Schedule 12d. – Reliability Forecast – Lakeland Frankton Sub-Network

Company Name **OtagoNet Joint Venture**

AMP Planning Period **1 April 2024 – 31 March 2034**

Network / Sub-network Name **Lakeland Frankton Sub-Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	6.7	9.4	9.4	9.4	9.4	9.4
12	Class C (unplanned interruptions on the network)	5.8	15.0	15.0	15.0	15.0	15.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.07	0.07	0.07	0.07	0.07	0.07
15	Class C (unplanned interruptions on the network)	0.07	0.16	0.16	0.16	0.16	0.16

Schedule 13.– Asset Management Maturity Assessment Tool

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .				
Question No.	**Function**	**Question**	**Score March 2023**	**Maturity Level Description**
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	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.
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	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.
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	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.
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	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.
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	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.

29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	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.
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	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.
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	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.
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	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.
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	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.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.

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	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
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	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).
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?	1.5	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.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	1.5	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.
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	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.
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	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.

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	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.
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?	1.5	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.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	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.
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	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.
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?	1.5	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.
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	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.

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	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.
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	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.5	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.
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	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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	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.
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	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.

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	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.
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	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.

Schedule 14a - Mandatory Explanatory Notes on Forecast Information

Company Name OtagoNet Joint Venture

For Year Ended 31 March 2024

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 9 December 2021.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Inflationary assumptions were used to calculate the nominal prices in the forecast. Nominal Prices are based on NZ Treasury's economic forecasts, as published in the Half Year Economic and Fiscal Update released December 2023.

	2024/25	2025/26	2026/27	2027/28	2028/29
Inflator CAPEX	4.100%	2.500%	2.200%	2.000%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 9.0% in 2023 and labour and external services costs have increased by 4.35%. These increases are included in the CAPEX forecasts for 2024 onwards.

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Nominal Prices are based on NZ Treasury's economic forecasts, as published in the Half Year Economic and Fiscal Update released December 2023.

	2024/25	2025/26	2026/27	2027/28	2028/29
Inflator OPEX	4.100%	2.500%	2.200%	2.000%	2.000%

In addition to the general inflation, material costs have increased by a weighted average of 9.0% in 2023 and labour and external services costs have increased by 4.35%. These increases are included in the CAPEX forecasts for 2024 onwards.

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

Annexure 4 - References

Ref #	Description
1	Electricity Distribution Information Disclosure Determination 2012 (consolidated as at 9 December 2021), ISBN 978-1-869459-59-8, Project no. 44933, Publication date: 9 December 2021, Commerce Commission, Wellington, New Zealand.
2	OJV's Strategic Plan.
3	ISO 31000:2009 Standard: Risk Management - Principles and Guidelines.
4	Health and Safety at Work Act 2015.
5	Electricity (Safety) Regulations 2010.
6	Electricity (Hazards from Trees) Regulations 2003.
7	Maintaining safe clearances from live conductors (NZECP34 or AS2067).
8	EEA Guide to Power System Earthing Practice 2019.
9	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/performance-accessibility-tool-for-electricity-distributors
10	https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/trends-in-local-lines-company-performance

Annexure 5 - Directors Approval

We, Peter William Moynihan and Robert Datema Jamieson being directors of companies which are parties to the OtagoNet Joint Venture certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The attached information of OtagoNet Joint Venture prepared for the purposes of clauses 2.6.1 and 2.6.6 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, 12d and 14a are based on objective and reasonable assumptions which both align with OtagoNet Joint Venture corporate vision and strategy and are documented in retained records.

Peter William Moynihan

Robert Datema Jamieson

Date: 28 March 2024