Shotover Country January 2016

Asset Management Plan 2016 - 2026

Publicly disclosed in March 2016

Contents

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0. Summary

0.1. Background and Objectives

OtagoNet Joint Venture (OJV) is the disclosing entity for the electricity lines businesses that convey electricity to much of rural Otago and to Frankton, supplying approximately 15,131 customers.

OJV's Asset Management Plan (AMP) provides an internal asset management framework for OJV's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination 2012 for the ten year planning period from 1 April 2016 to 31 March 2026. 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 year of the AMP along with any recent strategic, commercial, asset or operational issues from the wider business and defines the priorities and actions for the year ahead. It also forms the principal accountability mechanism between OJV's Governing Committee and its shareholders.

OJV's business goals are driven by its stakeholders' interests, of which shareholder's expectations and meeting customer expectations have a primary influence. Aligned corporate and asset management strategies have been developed to guide OJV's commercial operation, investment, risk management, business efficiency and customer satisfaction objectives.

OJV's commercial goal is to deliver a rate of return that fairly rewards shareholders for their significant initial investment and the significant ongoing capital expenditure required since acquisition. This creates a primary driver for OJV and formal accountabilities to the shareholder are in place for financial and network performance. Customers via the 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 aimed at ensuring standards are maintained or improved.

Stakeholder's interests are accommodated as far as possible while managing any conflicting interests by using a priority hierarchy considering safety, viability, pricing, supply quality and compliance in that order.

OJV has a contract with PowerNet Limited which is owned by OJV's shareholders, Electricity Invercargill (EIL) and The Power Company Limited (TPCL). The AMP is produced by PowerNet after extensive consultation throughout the business, with OJV's Governing Committee, and with OJV's customers. The AMP is approved by the OJV Governing Committee prior to 31 March of each year when it is publically disclosed.

0.2. Assets Covered

OJV's service area includes three electrically separate areas: the northern rural Otago area supplied by the Halfway Bush and Naseby GXPs, the southern rural Otago area supplied by the Balclutha GXP, and the Frankton/Lake Hayes area supplied by Frankton GXP. 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 15,131 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 with along with some domestic load concentrated in regional towns. The Frankton/Lake Hayes network is entirely underground and supplies a proportion of the newer residential and commercial developments in the area.

OJV owns and operates 33 zone substations with a 66/33 kV interconnecting station; there are also ten 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 distribution network in the Frankton area is underground and 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 rural network are relatively old, and the 2015 Information Disclosure shows an average 43% of weighted average expected asset life remaining for subtransmission lines and 48% 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.

0.3. Service Levels

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 of outage frequency, which translates to the number of interruptions that the average customer can expect per annum. OJV is forecasting a SAIFI of about 2.86 for the 2016/17 year.
- SAIDI is a measure of outage duration, which translates to the number of minutes that the average customer can expect to be without power per annum. OJV is forecasting SAIDI of about 226.6 for the 2016/17 year.

These projections are an average only, given the volatility in reliability statistics due to extreme weather events. OJV's network reliability has been heavily influenced by extreme weather events in recent years, and its medium-term aim is to gradually reduce this average.

Secondary service levels are also set for customer satisfaction for those customers who have experienced an outage (both planned and unplanned) regarding their satisfaction with the amount of time they were without supply and communication received or available about their outages. Independent surveys are undertaken annually to determine how customers perceive the service levels they receive from OJV and generally responses are very positive.

Other service levels maintained are the 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. For financial efficiency OJV has adopted a set of six metrics from the current Information Disclosure format and aims to maintain or improve them from current levels. 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%.

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

0.4. Development

Development may be driven by the need to create additional network capacity for supplying increasing demand, or by the need to maintain or improve service levels. These drivers are monitored and trigger points set to identify when development projects are needed. When a development trigger is reached, several options are considered with the most cost efficient option selected as a solution. Standardisation is a valuable strategy in providing cost efficiencies in the delivery of capital projects.

Forecasts for demand growth are required to help OJV predict when in future years the development triggers will be reached, thus enabling effective planning of future projects. Historical demand is trended and projected into future years while accounting for foreseeable future drivers that may cause a change to the current trend. Projections and associated planning are based on what is considered the most likely scenario, while OJV's strategy of deferring capital expenditure until necessary minimises the risk of overinvestment.

OJV's work programme includes the following capital expenditure on network development for 2016/17:

- Consumer Connections – several anticipated major development projects together with an allowance for other new connections to the network is budgeted at $4.6 million.
- System Growth – upgrades to the Puketoi area (including the Patearoa substation) and the Chrystalls Beach SWER line combine with the cost of finishing the Clydevale substation upgrade to contribute to a $2.4M budget for System Growth.

- Asset Relocations – a small budget of $119,000 is allowed for the relocation of miscellaneous poles or other assets as required.
- Quality of Supply – a continued program of network automation to allow faster location, isolation and supply restoration after a fault contributes to the $418,000 budget
- Other Reliability, Safety and Environmental – a programme of Neutral Earth Resistor (NER) installations at OJV substations together with an associated programme of transformer circuit breaker installations form the kernel of this $1.5M budget.

Total capital expenditure budget (including Asset Replacement and Renewal as described under "Lifecycle" below) is $14.73M for 2016/17, with budgets for the following two years set at $13.44M and $15.20M respectively.

0.5. Lifecycle

Once an asset has been installed it must be managed throughout its lifecycle to continue to fulfil its purpose for as long as required, and to minimise any adverse effects the asset might create. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service. At some point the asset will reach its end of life and will be retired from service. At that point the asset will be replaced (assuming the need remains) while the retired asset must be disposed of appropriately.

OJV's work program includes the following capital expenditure on asset lifecycle management:

- Asset Replacement and Renewal – replacement of assets that are at the end of their economic life, or in some cases major refurbishment of assets to extend their expected life. The 2016/17 budget is $5.6M dominated heavily by line renewals. The budgets for the following two years are set at $7.1M and $8.5M respectively, reflecting increased levels of line renewal work and the commencement of construction on the Merton Substation replacement.

The remainder of OJV's works program is made up of the following operational expenditure on asset lifecycle management:

- Asset Replacement and Renewal – minor refurbishment work that doesn't impact on an asset's valuation is budgeted at $497,000 per annum ongoing.
- Vegetation Management – a budget of $1.08M is allowed yearly for the trimming of trees to prevent contact with overhead lines.
- Routine and Corrective Maintenance and Inspection – inspection, testing and investigation of network condition and resulting maintenance or repair as well as general routine asset maintenance and repairs budgeted at $1.4M each year ongoing.
- Service Interruptions and Emergencies – reactive work following network faults and customer outages to locate, isolate and repair faulty network assets budgeted at $984,000 each year ongoing.

Total network operational expenditure is budgeted at about $4.0M each year ongoing. Additionally non-network operational expenditure will contribute approximately $2.2M per annum.

0.6. Risk Management

OJV is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. Risks associated with OJV's network are actively identified through regular reviews. Identified risks are then quantified in terms of the probability that an adverse occurrence will eventuate, and the scale of consequences of the occurrence for OJV. A risk matrix is then used to systematically combine the probability and consequence into a resulting level of risk. Risk management looks at the most appropriate options for reducing risk to acceptable levels using the following general methods:

- Terminate – not proceeding with risky activity or eliminating a risk by choosing an alternative approach.
- Treat – reduce probability and/or consequence of an adverse occurrence
- Transfer – engage a more suitable party to effectively manage a certain risk
- Tolerate – accept a low level risk as tolerable (including residual risk after treatment of higher level risks)

OJV's risk management framework recognises that resources for managing risk are finite. It may be appropriate to increase certain resources to manage risk appropriately however ultimately risk treatment measures identified need to prioritise using a philosophy of greatest risk reduction for the resources available. Many risks have been identified and are being managed under the following broad categories:

- Weather and Physical (including natural disasters and equipment failure)
- Safety and Environmental
- Human
- External Factors
- Corporate

For potential serious business interruptions OJV has developed a Business Continuity Plan and has a Pandemic Action Plan for use in the outbreak of any highly infectious illness. OJV also holds critical network spares and has contingency operating plans to support efficient restoration of supply following unexpected equipment failure as well as holding a range of business insurances.

0.7. Performance

For the financial year ending 31st March 2015 OJV's performance in summarised as follows:

Capital expenditure was 15.3% over target due mainly to an unusually high level of consumer connection expenditure, driven largely by increased irrigation demands.

Operational expenditure was 19.7% under target due largely to line and pole replacement work being categorised as CAPEX rather than OPEX work.

Reliability performance on the overall network was acceptable given the high number of storms during the year; however an irregularity in the 2012 Default Price-Quality Path Determination forced OJV to report a technical (but not actual) breach of the SAIFI supply quality limit.

Network efficiency performance was fair with the target of less than 5.0% for Loss Ratio achieved. The Capacity Utilisation target was not achieved, however the result was close to target and OJV recognises that standardisation of older 5 kVA transformers to 15 kVA units will impact on this figure.

Financial efficiency performance was well within the target upper limits.

0.8. Capability to Deliver

OJV has many systems, processes and tools to effectively and efficiently manage its network assets. The maintenance of these systems and the information that they contain requires dedicated staff. OJV's information systems hold a great deal of data about its network assets including technical details, location, operational states and condition. This data is collated and displayed in various ways to help support efficient decision making for OJV's asset management planning and activities.

OJV's business is funded from the revenue received from customers via several electricity retailers and in return OJV maintains a network for the conveyance of electricity to these customers within certain service levels. Revenue is closely tied to the value of assets as set out in a "price path" determined by the regulating authority; the Commerce Commission. Significant expenditure is required each year to maintain network assets and to develop the network to meet increasing customer demand.

Staffing and contracting resources is an ongoing issue that OJV is managing; OJV's Annual Works Program recognises existing constraints, and incorporates future management of resourcing levels. With the internalising of PowerNet's field services in the area from 1st April 2016 OJV will rely on internal field services to carry out much of the operational, maintenance and development work on its network, but it will also utilise local contractors where additional resources are required.

1. Background and Objectives

OtagoNet Joint Venture (OJV) is the disclosing entity for the electricity lines businesses that convey electricity to much of rural Otago and to Frankton, supplying approximately 15,131 customer connections on behalf of twelve energy retailers. OJV discloses on behalf of the following entities:

- OtagoNet, which distributes power to rural Otago.
- Electricity Southland Limited (ESL), which owns the Lakeland Network located at Frankton.

The Lakeland network is not contiguous to the OtagoNet network and falls under the threshold that triggers additional subnetwork disclosures. The ownership of OtagoNet and ESL is identical:

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

The interrelationship of these entities, their various holding companies and shareholders, and PowerNet (the company that provides network management services to OJV), is described in OJV's annual report along with along accounting treatment of results.

1.1. Purpose Statement

The purpose of OJV's Asset Management Plan (AMP) is to provide an internal governance and management framework for asset management practice on OJV's network. Disclosure in this format is also intended to assist in meeting the requirements of Section 2.6, Attachment A and Schedules 11, 12 and 13 of the Electricity Distribution Information Disclosure Determination 2012.

1.2. Asset Management Objectives

OJV's asset management objectives which this AMP endeavours to deliver are to:

- Set service levels of the electricity distribution services supplied by OJV that will meet customer, community and regulatory requirements.
- Understand the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Have an ever-increasing knowledge of OJV's asset locations, ages and conditions as well as the assets' likely future behaviour as they age and may be required to perform at different levels.
- Have robust and transparent processes in place for managing all phases of the network life cycle from design, procurement and installation to disposal.
- Have adequate provision for funding all phases of the network lifecycle.
- Have adequately considered the classes of risk OJV's network business faces and that there are systematic processes in place to manage identified risks.
- Make business decisions within systematic and structured frameworks.

This AMP is not intended to be a detailed description of OJV's assets (these lie in other parts of the business), but rather a description of the thinking, the policies, the strategies, the plans and the resources that OJV uses and will use to manage the assets.

1.3. AMP Planning Period and Director Approval

OJV's Asset Management Plan (AMP) is prepared annually by PowerNet however an "AMP update" is produced in place of a full AMP two years within each five year default price path period as allowed for by the Electricity Distribution Information Disclosure Determination 2012 (latest amendments incorporated). The AMP update which focusses on updates to the development and lifecycle works and expenditure is a cut down version of the full AMP represented by this document.

This latest edition was prepared during August 2015 to March 2016 and covers the ten year period from 1 April 2016 to 31 March 2026. It was approved by OJV's Governing Committee on 31 March 2016 (see Appendix 1) and publicly disclosed at the end of March 2016.

There is a degree of uncertainty in any predictions of the future with the immediate future reasonably predictable and the longer term becoming more and more uncertain.

The first year of the AMP is considered reasonably certain. Planned capital works are generally well planned and only subject to minor variations. New customer connections are driven by turbulent commodity markets, public policy trends and possible generation opportunities so while trends are reasonably predictable, year to year variation around those trends can still be significant, especially with larger capacity connections that tend to have lower and more sporadic connection rates but have larger individual impact.

Maintenance works are relatively certain as most tasks tend to be ongoing, repeated year after year unless step changes are warranted due to age profiles or if new initiatives are introduced, but these changes are planned in advance. Reactive maintenance requirements are less predictable, as network faults on the overhead lines that form the large majority of the network are heavily influenced by weather.

The two to four year timeframe has lower certainty. However customer connection rates, maintenance and response to service interruptions are expected to continue the current trend to a reasonable degree. Major projects are typically identified and scheduled however as detailed scope, design and costings are developed alternative options may be progressed influencing expenditure and timing. External influences tend to cause more minor projects to be considered within this timeframe each year especially the changing perceptions around health and safety.

The final five year period of the AMP's ten year planning horizon has little certainty if any. Projects for age based replacements can be proposed and growth trends can be used to predict when capacity triggers will be reached. However standards may change and new maintenance philosophies may be developed (and continual improvement in asset management practice means this is likely) potentially having a large impact on scope and timeframes for these projects. Experience shows these changes and other external influences are likely to introduce and reshape major and minor projects within this time frame but are very difficult to predict.

1.4. Drivers and Constraints

OJV's business goals are driven by its stakeholders' interests, of which shareholder's expectations and meeting customer expectations have a primary influence. Also shaping business operation is the wider context in which the business operates which includes a number of drivers. These drivers range from governmental and regulatory strategies that may create incentives or impose constraints, to absolute issues such as the unpredictability of weather or the laws of physics.

This section describes the identification of OJV's stakeholders, their interests in OJV, how these interests are met and how conflicts between stakeholder's expectations are managed before identifying other influences that drive and shape OJV's business.

1.4.1. Stakeholder Interests

The stakeholders OJV has identified are listed in the following tables with the stakeholder's interests and how these interests are identified shown in Table 1 and Table 2 respectively. Table 3 then shows how stakeholder's interests are accommodated in OJV's asset management practices. 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 it is in an 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).

Table 1: Key stakeholder interests

Interests:	Viability	Price	Quality	Safety	Compliance
Shareholders	✓	✓	✓	✓	✓
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	✓	✓		✓	✓

Table 2: Identifying stakeholder's interests

Stakeholder	How Interests are Identified
Shareholders	• By their approval or required amendment of the SOI • 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)	• Governing Committee Chairman/ Chief Executive weekly meeting • Governing Committee/Chief Executive/PNL Staff mthly meeting
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 in regard to 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
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 3: 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 maintain Service Levels within targets and the revenue set to provide the required returns.
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 constrained by the price path threshold regime. Prices will be restrained to within the limits prescribed by the price path threshold, unless it comprises 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 expected to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.
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, all enclosures are kept locked and all exposed metal 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 carriageway within the constraints faced in regard to private land and road reserve.
Compliance	Compliance is necessary with statutory requirements ranging from safety to disclosing information.	All safety issues will be adequately documented and available for inspection by authorised agencies. Performance information will be disclosed in a timely and compliant fashion.

OJV's commercial goal is to deliver a rate of return that fairly rewards shareholders for their significant initial investment and the significant ongoing capital expenditure required since acquisition. This creates a primary driver for OJV and formal accountabilities to the shareholder are in place for financial and network performance – refer section 1.6.

Customers via the 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 aimed at ensuring standards are maintained or improved. See sections 3 and 7 for details of these surveys, customer feedback and performance targets OJV sets.

OJV is also subject to the requirement to compile and publically disclose performance and planning information (including the requirement to publish an AMP) and OJV is subject to price and quality regulations which guide prices and require no material decline in network reliability measures. These requirements are established under Part 4 of the Commerce Act 1986.

OJV is also subject to regulatory restrictions on generating and retailing energy 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 being increasingly required to give effect to many aspects of government policy.

1.4.2. Managing Conflicting Stakeholder Interests

When a conflict of stakeholder interests has been identified OJV must arrive at an appropriate resolution. To achieve this outcome the following priority hierarchy is used to analyse the conflicting issues and options available:

1. **Safety**. Top priority is given to safety. The safety of staff, contractors and the public will not be compromised even if budgets are exceeded.
2. **Viability**. Second priority is viability (as defined above), because without it OJV will cease to exist which makes supply quality and compliance pointless.
3. **Pricing**. OJV will give third priority to pricing as a follow on from viability (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**. Supply quality is the fourth priority. Good supply quality helps make 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 will be presented to management. A decision may then be made by the management team or escalated to the OJV Governing Committee if appropriate.

1.4.3. Other Influences

There are several other issues that are not directly related to stakeholders but have a significant impact on OJV's asset management practice and strategies may be developed to effectively manage these issues. These issues are as follows:

- Competitive pressures from other lines companies which 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) and at bulk generation level (wind farms).
- Advancing technologies, such as solar generation coupled with battery storage, which could strand conventional wire 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.
- The laws of physics which govern such fundamental issues as power flows, losses, insulation failure and faults.
- Physical risk exposures. Exposure to events such as flooding, wind, snow, earthquakes and vehicle impacts are generally independent of the strategic context. Issues in which OJV's risk exposure might depend on the strategic context could be in regard to natural issues such as climate change (increasing severity and frequency of storms) or regulatory issues (for example if the transport agency required all poles to be moved back from the carriageway).

1.5. Strategy and Delivery

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

1.5.1. Corporate Vision

To operate as a successful business in the distribution of electricity in the Otago region.

1.5.2. Corporate Strategy

Key corporate drivers from OJV's Strategic Plan are:

- Deliver to customers an economic, safe, efficient and quality electricity supply and meet all legislative requirements
- Maintain and enhance the long term value of assets, business units, products and investments
- Deliver a reasonable commercial return on equity
- Achieve a long term reliable electricity supply

1.5.3. Asset Management Strategy

OJV's asset management strategy follows these guiding principles:

- Safety by design using the ALARP (as low as reasonably practicable) risk principle
- Minimise long term service delivery cost through condition assessment and refurbishment
- Replace assets at their (risk considered) economic end of life
- 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

1.5.4. Interaction of Goals/Strategies

OJV's corporate vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 4.

Table 4: Corporate and Asset Management Strategy Linkage

Corporate Strategies
Deliver to customers an economic, safe, efficient and quality electricity supply and meet all legislative requirements
Maintain and enhance the long term value of assets, business units, products and investments
Deliver a reasonable commercial return on equity
Achieve a long term reliable electricity supply

Asset Management Strategies				
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	✓	✓	✓	✓
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				✓

1.6. Key Planning Documents

In addition to the AMP the following documents are produced annually by PowerNet on OJV’s behalf and approved by OJV as part of the company’s planning processes.

1.6.1. 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 further in section 8.

1.6.2. Annual Business Plan

Each year, the first year of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into OJV's Annual Business Plan (ABP). The preparation of an ABP for OJV is required under the joint venture agreement, and forms the principal accountability mechanism between OJV's Governing Committee and its joint venture parties, Electricity Invercargill Limited and The Power Company Limited (via their respective holding companies Pylon Limited and Last Tango Limited). The AWP for the year ahead is an important component of the ABP.

The ABP includes financial performance projections for after-tax returns, equity and return on equity; and quality performance projections for SAIDI and SAIFI which are set in the AMP (section 3). These projections are given over a three year period, they form the heart of the asset management activity and implicitly recognise the inherent trade-off between price and supply quality.

The ABP also 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:

- Mission Statement, Objectives Statement and Critical Success Factors
- Commercial Objectives and Customer Service Objectives
- Annual Works Programme (first three years)
- Business Plan Financials and Business Unit Reports

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

1.7. Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between OJV's vision, asset management objectives, business drivers, strategies and key planning documents is shown in Figure 1 and is summarised as follows.

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 Governing Committee.

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 even 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.

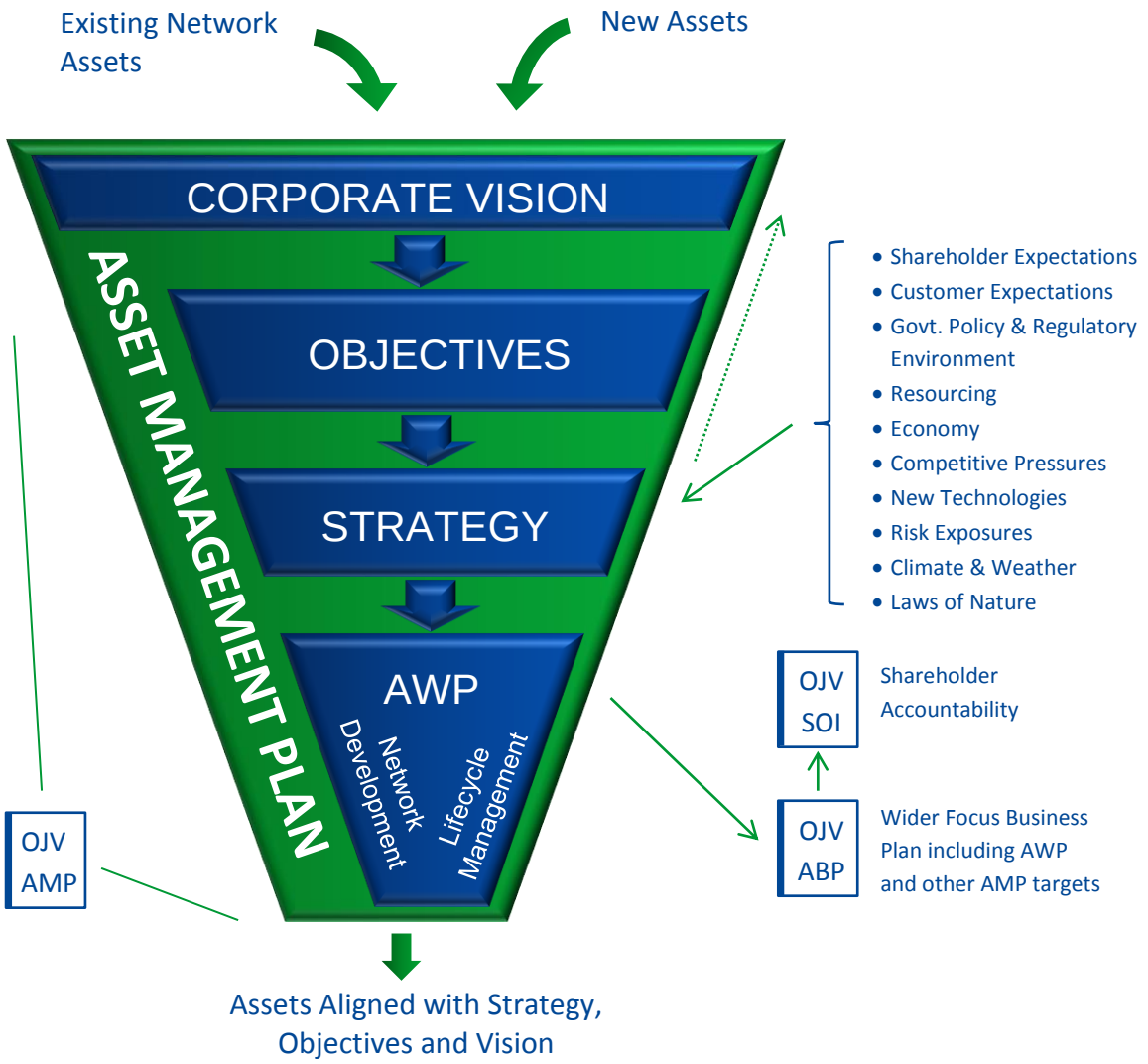

Figure 1: Interaction of Objective, Strategies and Key Plans

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 incorporating (and especially) the AWP, which is prepared in a format assisting communication of key deliverables, sets and drives asset management works and expenditure to reshape network assets. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and ultimately OJV's corporate vision while meeting stakeholder expectations, especially the shareholder and network customers.

Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP together with any wider business issues providing the overall business planning summary used by the wider management team and OJV Governing Committee. The SOI incorporates performance targets from the AWP including key asset management targets forming the accountability mechanism between the OJV Governing Committee and the shareholder.

1.8. Accountabilities and Responsibilities

1.8.1. Accountability at Governance Level

As OJV uses PowerNet as their contracted management company to manage the assets there is effectively a two-tier governance structure. The first tier of governance accountability is between OJV's Governing Committee and the shareholders with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes OJV's Governing Committee intimately accountable to OJV's shareholders for these important asset management outcomes whilst the inclusion of financial targets in the statement makes OJV's Governing Committee additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. Members of the Governing Committee are:

- Alan Harper
- Duncan Fea
- Neil Boniface JP
- Doug Fraser

The second tier of governance accountability is between OJV's Governing Committee and PowerNet with the principal mechanism being the management contract that specifies a range of strategic and operational outcomes to be achieved.

1.8.2. 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 Governing Committee and PowerNet.

1.8.3. Accountability at Management Level

There are six level two managers reporting directly to PowerNet's Chief Executive with the principal accountability mechanisms being their respective employment agreements.

The individual manager who has the most influence over the long-term asset management outcomes will be the Chief Engineer through his responsibility for preparation of the AMP which will guide the nature and direction of the other managers' work.

1.8.4. Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team (under the Chief Engineer), Technical and Network Performance Team and Customer, Metering and Distribution Services Team 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.

From 1st April 2016, Otago Power Services Limited will cease to trade as a separate entity, and will be incorporated into PowerNet. From that point forward distribution projects will typically utilise PowerNet's in-house field services while whilst technical and major projects will use a combination of in-house resources and external contractors and consultants.

Contracts will be utilised where external contractors are required, structured on the following mechanisms:

- Purchase Order – generally only minor work
- Fixed Lump Sum Contract – generally on-going work
- 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.

1.8.5. Accountability at Work-face Level

PowerNet's internal field staff sit and are managed within PowerNet's Technical and Network Performance Team and Customer, Metering and Distribution Services Team to deliver work respectively divided into technical or distribution projects. External contractors are typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets.

The principal accountability mechanism when utilising these external contractors is through contracts that reflect the outcomes PowerNet must create for OJV.

1.8.6. Key Reporting Lines

OJV's ownership, governance and management structure is depicted in Figure 2. The OJV Governing Committee receives monthly reports that cover the following items:

- Network reliability – this lists all outages over the last month, and trends regarding the SOI reliability targets
- Network Quality – detail of outstanding supply quality complaints and annual statistics on them
- 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 – monthly, year-to-date (YTD) and project life expenditure actuals and forecasts on each works programme item, with notes on major variations

Any new project over $100,000 added to the AWP, or variation by more than +10% or -30% from an amount already in the approved AWP, requires approval from the OJV Governing Committee. 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.

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. Generally most projects in the AWP are approved by the OJV Governing Committee as part of ABP process in the previous year.

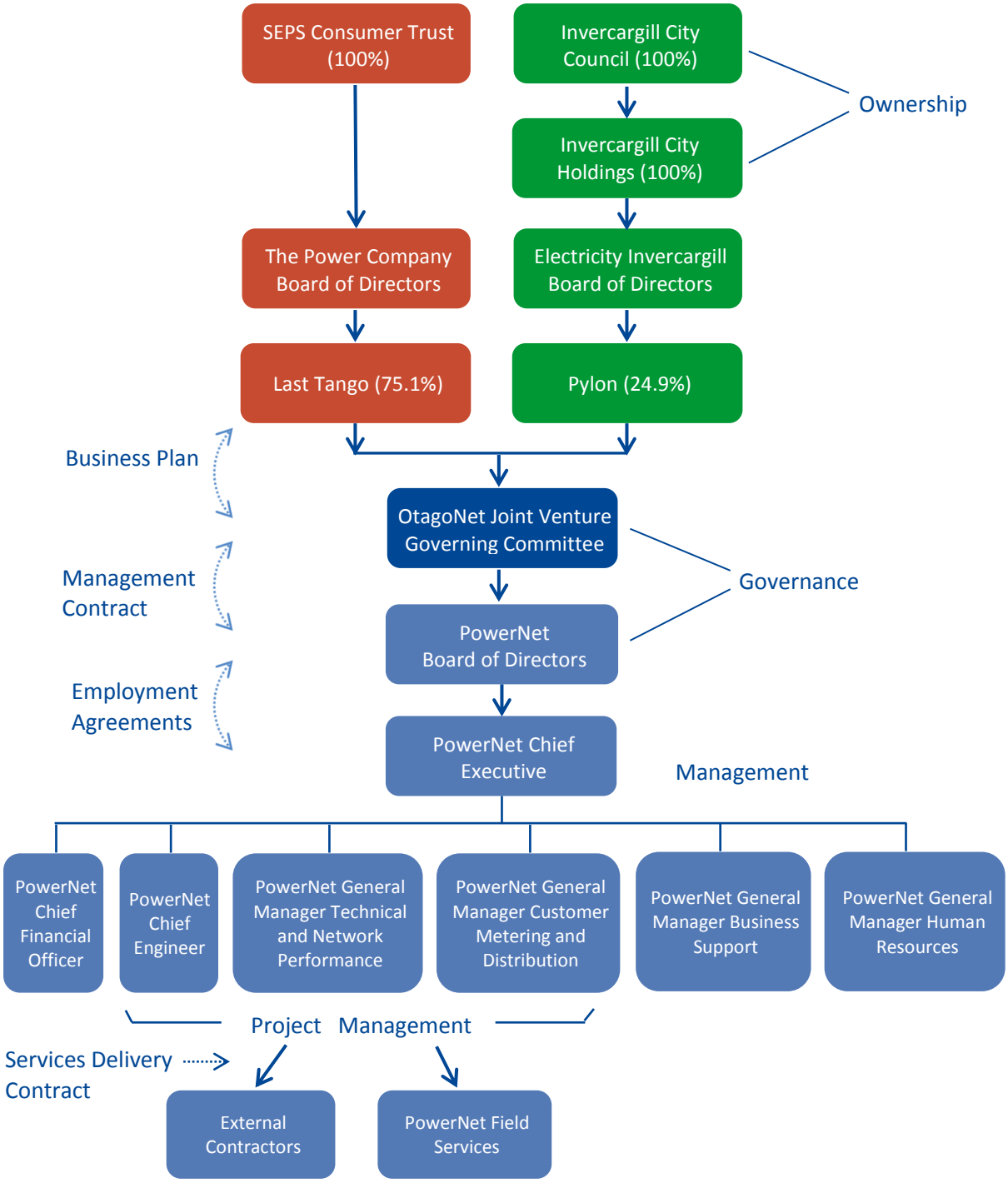

Figure 2: Governance and management accountabilities

1.9. AMP Communication and Participation Processes

A first draft of the AMP is generally created by November each year and is circulated around management for review and comment. The 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 AMP draft.

Customer perceptions and expectations gauged from surveys and customer consultation evenings are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate from this process will be incorporated into the AMP and AWP as necessary.

1.9.1. Management and Operations Participation

The planning team is in regular contact throughout the year with those responsible for implementing the current AWP to monitor progress and any variations as they arise with large capital projects covered in a formal monthly review meeting. Any changes are consolidated into the initial AWP revision and further revisions are developed in consultation with the management, project managers and field staff who will be involved in its implementation.

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. "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. This tends to be an iterative process as variations generally need to be accounted for up until the information disclosure date.

1.9.2. Governance Participation

The initial consolidated AWP is submitted to the OJV Governing Committee supported by a presentation. Any business cases required for large capital projects or other papers covering any novel projects are submitted in advance and will be included in the AWP presentation. After their initial review the Governing Committee may request clarifications or changes which are then incorporated into the AWP. These changes tend to be more commercially motivated but will also recognise the need to address any identified health and safety related issues as a high priority. Any recommended changes to the wider AMP that the Governing Committee 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 Governing Committee for review in February. The Governing Committee may request further changes to be completed before giving final approval for disclosure at the end of March.

1.9.3. Post Disclosure Communication

Once the AMP has been finalised and publically 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.

A preliminary communication meeting is then held with internal field staff and key contractors, to highlight the body of work for the year ahead, with particular focus on 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 remain in contact with the project managers throughout the year to monitor progression of the AWP and ensure agreement on any significant variations as design and implementation progresses.

1.10. Assumptions

Planning is based on the assumption 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.

It is assumed that growth will continue to occur at an accelerated rate in the Maniototo Valley and neighbouring areas as farmers install spray irrigation to meet Otago Regional Council requirements. A moderate load increase will occur in the Milburn area due to forestry-related expansion, with the possibility of further upward step changes in the future. And irrigation combined with more stringent requirements on dairy milk chilling will increase load particularly in the Clydevale area.

Otherwise it is assumed that growth rates will be similar to historic trends. Developers rarely let OJV know of their plans keeping large projects confidential until the last minute. Any major development could require significant new network to be built however planning for possibilities would inevitably lead to overinvestment. No major developments are anticipated in coal, gas, oil, mineral extraction, etc. or processing either in the region or off shore which might significantly increase electrical load in the network area. Similarly no material decline in meat or wool markets is anticipated, and it is assumed that the Oceana Gold mine at Macraes Flat will continue to operate at its current level of capacity.

No step changes in underlying growth are considered likely based on historical trending over a long period. Population growth for sizing of equipment is based on the high projection.

Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.

Distributed generation is assumed to develop slowly with little impact over the ten year planning horizon. The current rate of connection is quite manageable with the first adopters typically reducing load on network assets. A large increase in connections could lead to upgrade requirements to maintain supply quality which could come about through government incentives or unexpected technology breakthroughs.

It is assumed that plug-in electric vehicles will not penetrate the local vehicle fleets sufficiently to require investment in extra capacity within the planning period. At present electric vehicle uptake is

concentrated in the main centres, and vehicle owners are encouraged to charge their vehicles during off-peak periods.

No changes are anticipated in present regulation. Any changes are likely to add additional cost. For example outages less than one minute aren't recorded against reliability KPIs; this allows a lower cost network automation solution which would be less appropriate if the one minute allowance were removed.

The standard life of assets is based on the ODV asset life, with actual replacement done on a condition basis. Equipment housed indoor will often exceed ODV life whereas the harsher coastal environment tends to shorten life for outdoor assets in these regions.

Abnormal price movements are difficult to predict and not allowed for in estimates.

Industry specific inflationary rates where available are used to account for increasing costs; otherwise adjustments are made according to CPI.

1.11. Potential Variation Factors

- Cost and time estimates
- Variation in inflation rates and/or exchange rates
- Staffing resource loss or inability to recruit as required
- Reactive work carrying from the estimated level – e.g. due extreme weather
- Equipment failure (especially large capital plant) which may influence future economic options
- New safety issues identified and initiatives created
- Reprioritisation as new work activities are identified
- Detailed analysis of the available options for projects commencing in the short term, which may indicate an alternative approach is preferable to that assumed for long-range forecasting
- Demand growth variation from anticipated levels, especially new large industry or customers or conversely loss of existing industry or customers

2. Assets Covered

This section summarises OJV's assets and asset configurations, but begins by describing OJV's geographical coverage, what sort of activities the underlying community uses electricity for, and the issues that are driving key asset parameters such as demand changes.

2.1. Service Areas

OJV's service area includes three electrically separate areas:

- The northern rural Otago area bounded by Waitati, Shag Point, Falls Dam and Lake Mahinerangi.
- The southern rural Otago area bounded by Taieri Mouth, Beaumont, Waipahi, and the MacClennan Range
- The Frankton area between Lake Hayes and the Frankton arm of Lake Wakatipu, consisting of several non-contiguous sections as the area is serviced by both ESL and Aurora.

Note that for the purposes of information disclosure the Frankton area, having less than 25km of distribution lines and less than 2000 ICPs connected, is not considered a sub-network and therefore values presented in this AMP for OJV are generally inclusive of those for the Frankton network.

Figure 3: OtagoNet Distribution Area

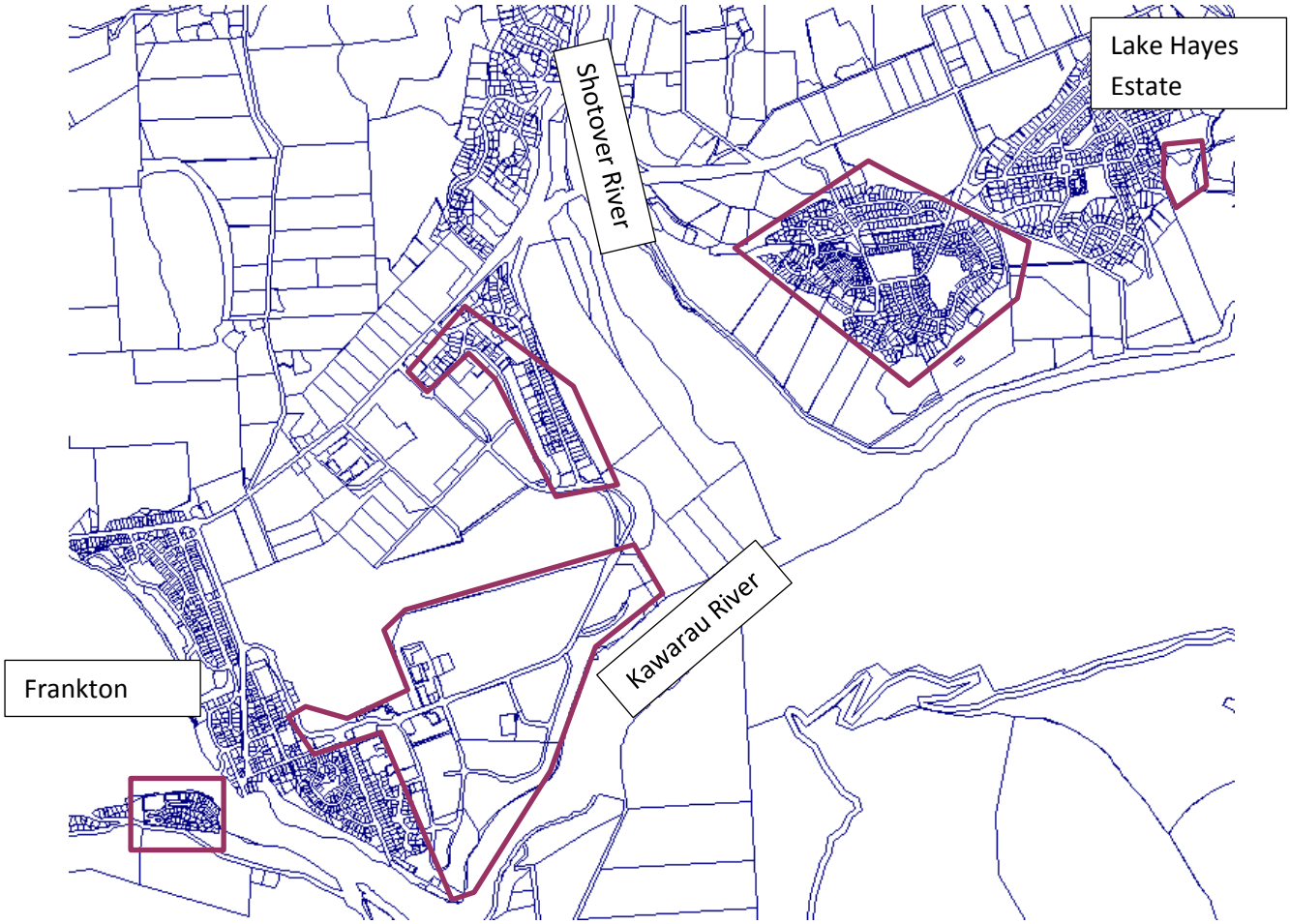

Figure 4: ESL Distribution Area

Topography is as follows:

- Dry flat plains, rolling hills and mountainous areas in the inland Central Otago area that includes townships of Naseby and Ranfurly, the Macraes Flat gold mine and stretches as far south as Middlemarch, Clarks Junction and Hindon.
- Rolling countryside along the East Otago coast that includes townships of Waitati, Waikouaiti and Palmerston.
- Flat fertile plains and rolling hills in the South Otago area that includes the townships of Milton, Balclutha, Owaka and Clinton.
- Small plateau bordered by lakes and mountains in the Frankton area with rapidly increasing urbanisation.

2.1.1. Key Industries

Large consumers within the network area include sheep, beef and dairy farming, extensive meat and dairy processing, forestry and timber processing. Most of the large and small towns in the service area are rural service towns.

The area's economic fortunes will therefore be strongly influenced by:

- Markets for basic and specialised meats such as beef, mutton and lamb.
- Markets for dairy products.
- Markets for processed timber.
- Markets for black and brown coal.
- Government policies on mining of coal.
- Government policies on forestry and nitrogen-based pastoral farming.
- Access to water for crop and stock irrigation, especially in north and central Otago.

The impact of these issues is broadly as described in Table 5.

The recent increase in new connections for irrigation indicate the farming sector is willing to invest and create new load points and OtagoNet responds to this through its network development and reliability planning.

Major consumers have significant impact on network operations and asset management priorities. Significant single loads are:

- Oceana Gold's 23 MVA of load on the Ranfurly substation requires a 66kV line, large dual rated 33/66kV step-up transformers and two heavy 33kV lines from the Naseby GXP.
- Trustpower's 12.25MW generation station also requires the 66kV supply at Ranfurly for energy transmission and embedded connection to the major Oceana Gold customer.
- Pioneer Generation's Falls Dam power station requires enhanced 33kV line regulation and arrangements at the Oturehua substation.
- Silver Fern Farms Finegand plant's 7MVA of load has 33 kV switching between three supplies to provide security to it and to customers on three downstream zone substations.
- Fonterra's Stirling cheese plant has 33kV switching between two supplies to provide fast 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 11kV supplies and automatic change over switchgear to deliver its required security.
- Southern Generation's Mount Stuart wind farm that connects into the Glenore to Lawrence 33kV line.
- Danone's Dairy Processing plant at Clydevale.

Table 5: Impact of Regional Economic Issues

Issue	Visible Impact	Impact on OJV's Value Drivers
Shifts in market tastes for beef, mutton, lamb	May lead to a contraction of demand by these industries.	Reduces asset utilisation. Possible capacity stranding
Shifting markets for dairy products	May lead to a contraction of demand by these industries.	Reduces asset utilisation. Possible capacity stranding
Shifting markets for timber	May lead to a contraction in demand by these industries	Reduces asset utilisation. Possible capacity stranding
Shifting markets for coal	May lead to a contraction in demand by these industries	Reduces asset utilisation. Possible capacity stranding
Government CO_2 Policy	May lead to a contraction in demand by industries May create new process requirement for industries	Reduces asset utilisation. Possible capacity stranding New capacity required
Government policy on nitrogen-based farming	May lead to contraction of dairy shed demand. May lead to contraction of dairy processing demand.	Reduces asset utilisation. Possible capacity stranding
Access to water	May lead to increased irrigation demand.	Increases asset utilisation but without corresponding increase in load factor

2.1.2. Load Characteristics

Domestic

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 5 and Figure 6 respectively.

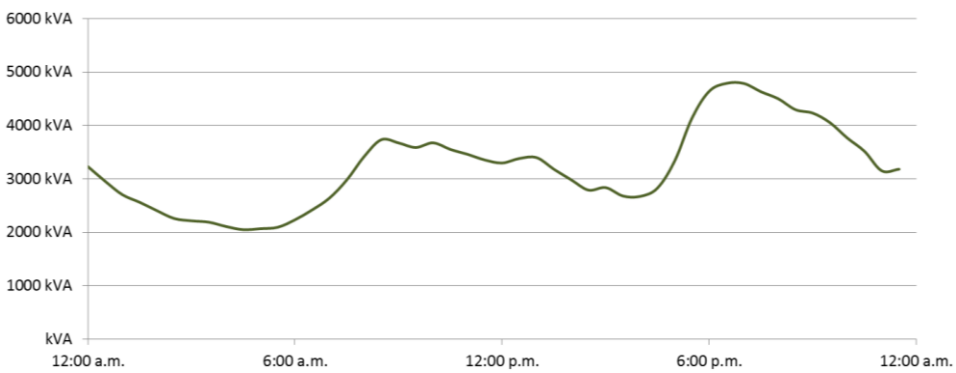

Figure 5: Typical Domestic Daily Load Profile

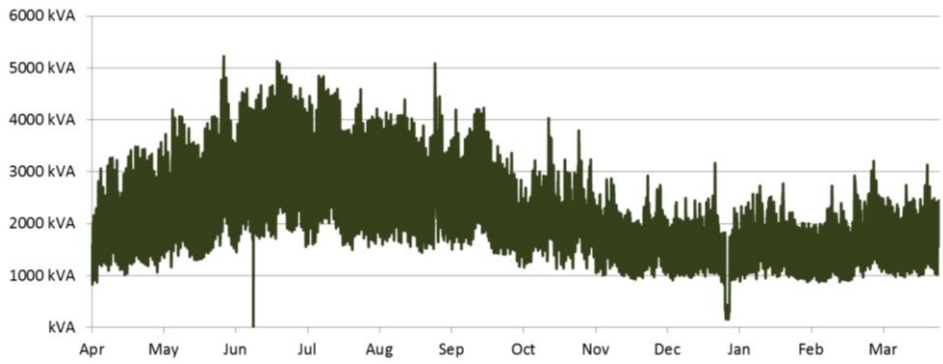

Figure 6: Typical Domestic Feeder Yearly Load Profile

Farming

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 with some 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 7 and Figure 8.

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.

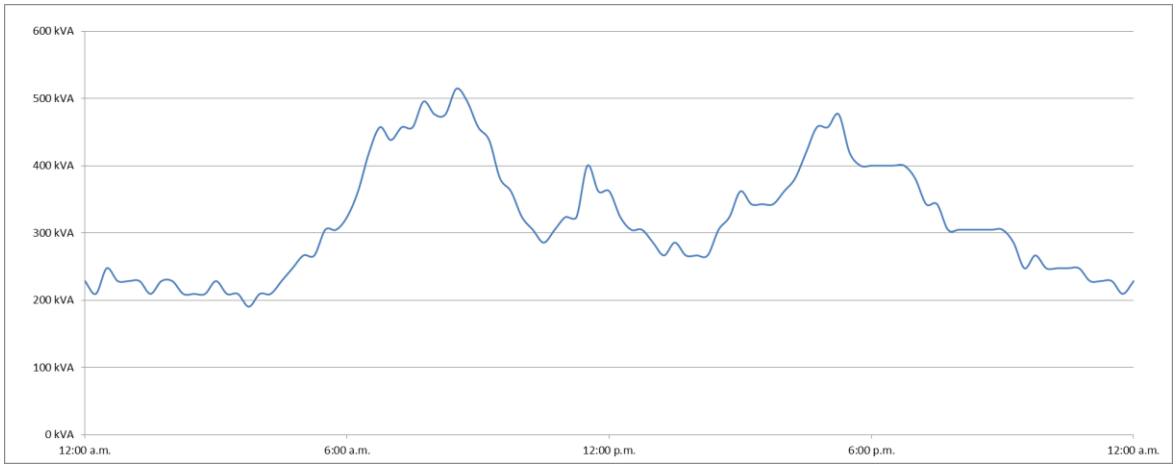

Figure 7: Typical Rural (Farming) Feeder Daily Load Profile

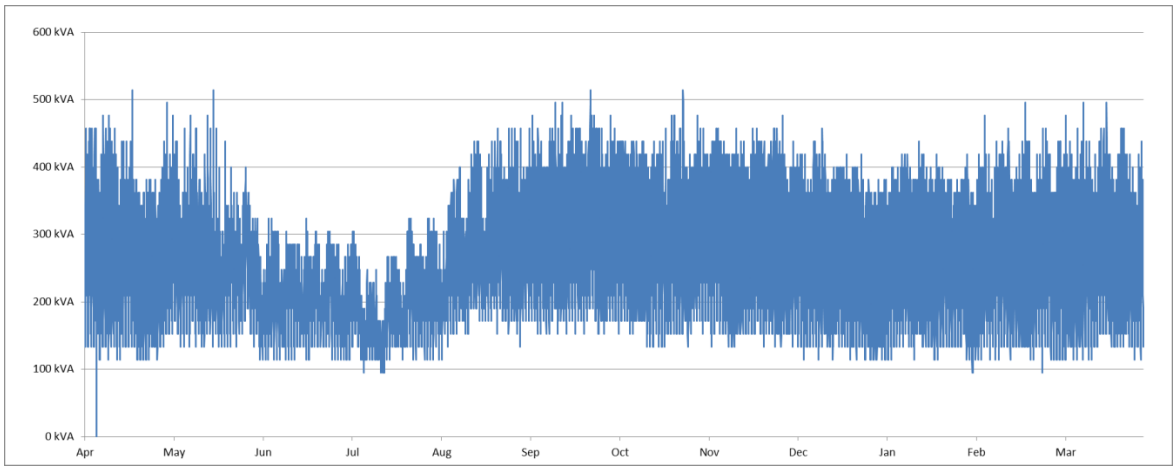

Figure 8: Typical Rural (Farming) Feeder Yearly Load Profile

Sawmills

Usage at sawmills due to processing and kiln drying of the product. There is also some wood-chipping of logs for export and these have some very large motors with poor starting characteristics.

Dairy Processing

Load characteristic is dependent on milk production and the movement of milk between processing plants to maximise plant efficiency.

Freezing Works

The load characteristics are similar to the dairy processing but with the off season 1-2 months later depending on the markets and production.

Mining

The mining load experienced in Otago has a very flat load profile maintained 24 hours per day all year round.

2.1.3. Energy and Demand Characteristics

Key energy and demand figures for the year ending 31 March 2015 are as shown in Table 6.

Table 6: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	425.8 GWh	Steady increase
Maximum Demand[1]	61.79 MW	Steady increase
Load Factor	79%	Constant
Losses	4.2%	Recent step drop arising from change in metering point for Macraes Flat gold mine load

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

It is particularly hard to extract underlying growth rates from historical data as both maximum demands and total energy conveyed, as recorded for any year, are heavily dependent on the weather. This variation tends to swamp the effect of the relatively low growth rates. Mathematical treatment such as "best fit" curve application yields completely different results when applied to different time periods i.e. previous 5 years, 10 years, 20 years etc. Shorter time periods give variable results due to the large influence of each particular calendar year, while longer time periods do not account for recent trends. Growth rates therefore tend to reflect an educated estimate on the part of the planning engineer, and accordingly certainty with the growth rates shown in Table 6 is low. Section 4.2 examines the analysis, trending and forecast of growth for OJV.

2.2. Network Configuration

To supply OJV's 15,131 customers OJV owns and operates a single electrical network across three geographically distinct areas described in Section 2.1. The northern area consists of two halves connected by a 33kV line paralleling the Pig Root[2] that can supply about half of the inland Central Otago's maximum demand.

2.2.1. Bulk Supply Points and Embedded Generation

Balclutha GXP is supplied by a double circuit tower 110kV diversion (not a tee) from the Gore – Berwick single circuit 110kV pole line. Supply is taken through eight 33kV feeders from the Balclutha GXP.

Frankton GXP is supplied off a dual circuit 110 kV spur from Cromwell and supplies the Remarkables zone substation via two 33 kV circuits whilst also supplying Queenstown, Arrowtown, and the remaining Frankton areas.

Naseby GXP is supplied off a single circuit 220kV tower line from Roxburgh to Livingstone and supplies the Ranfurly zone substation via two 33kV circuits.

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 circuits heading up the coast from Dunedin to Palmerston (one at 110 kV and one at 33 kV) and also supplies power at 33 kV to Aurora's western Dunedin network.

The 12.25MW 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 Macraes Flat Oceana Gold mine load.

The Pioneer Generation Limited (PGL) 1.25MW Falls Dam hydro scheme is connected to the 33kV network at Oturehua. PGL owns the equipment to enable connection onto the OtagoNet 33kV line.

[2] Yes it is spelt this way… named by John Turnbull Thomson.

The Southern Generation Limited Partnership (SGLP) 7.65MW Mt 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 7: OJV Bulk Supply Characteristics

Grid Exit Point	Voltage	Rating	Firm Rating	Maximum Demand 2014/15	Coincident LSI* Demand 2014/15
Balclutha	110/33 kV	60 MVA	37 MVA	27.6 MW (08:30 03/04/14)	24.9 MW (10:30 26/05/2014)
Frankton	110/33 kV	146 MVA	80 MVA	2.6 MW (09:30 15/07/14)	0.8 MW (10:30 26/05/2014)
Naseby	220/33 kV	70 MVA	35 MVA	28.6 MW (21:00 26/03/15)	0.7 MW (10:30 26/05/2014)
Halfway Bush	220/110/33 kV	200 MVA (33 kV[3])	0[4] MVA (33 kV[3])	5.7 MW (18:30 14/08/14)	5.4 MW (10:30 26/05/2014)
Paerau	66 kV	24 MVA	15 MVA[5]	12.4 MW (09:30 19/08/14)	6.6 MW (10:30 26/05/2014)
Falls Dam	33 kV	1.25 MVA	1.25 MVA	1.3 MW (02:30 14/07/14)	1.3 MW (10:30 26/05/2014)
Mt Stuart	33 kV	8 MVA	7 MVA[5]	7.5 MW (19:00 30/05/14)	1.5 MW (10:30 26/05/2014)

* LSI: Lower South Island

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

2.2.2. Subtransmission

OJV's subtransmission network comprises two electrically separate networks as depicted in Figure 9, along with a small amount of cable connecting the Remarkables substation to the Frankton GXP. The subtransmission network comprises 47 km of 110 kV line, 74 km of 66 kV line, and 587 km of 33 kV line, and has the following characteristics:

- It is almost totally overhead except for short cable runs at GXP's 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.

[3] The Halfway Bush 110 kV load is not supplied by any supply transformers. The load is served from the 110 kV bus, which is connected to an interconnector transformer and lines connecting to Roxburgh and Berwick.

[4] At present Halfway Bush operates with a split 33 kV bus. The bus section that OJV connects to is supplied by one 100 MVA transformer, therefore it has no continuous n-1 security. With the completion of the Halfway Bush 33 kV switchboard upgrade in 2018, OJV will connect to both halves of the bus and receive n-1 security.

[5] 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.

OtagoNet's 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 and this focuses asset management towards the condition and integrity of these lines. As poor condition lines are rebuilt they are generally rebuilt with concrete poles, galvanised steel crossarms and clamp-top insulators to maximise reliability and life.

2.2.3. Zone Substations

OJV owns and operates 33 zone substations with a 66/33 kV interconnecting station (at Ranfurly). A description of each zone and its security level is given in Table 8. Additionally there are eight 33/0.415 kV distribution transformers supplied direct off the 33 kV subtransmission network at Balmoral Water Scheme, Big Sky Dairy, Cormack, Hore's Pump, O'Malley's House, O'Malley's Pump, Rough Ridge and Tisdall; a site at Mount Stuart where 33 kV switching exists but the customer connection takes place at 33 kV; and a 2.2 MVA site at Greenfield where a 33 kV regulator, circuit, and three 33/0.415 kV transformers are maintained.

2.2.4. Distribution Network

In the Frankton area the distribution consists of rings connecting the Kawerau Falls, Remarkables Park, Shotover Country and Shotover Park Developments to the Remarkables substation; with a single cable over the Shotover River connecting a second set of rings in the Shotover Country area. The network is primarily 22 kV XLPE cable with a small amount of 11 kV XLPE cable near Shotover Park.

In rural areas the configuration is almost totally radial with little interconnection. In particular, the mountainous topography and the distances in the inland Central Otago area preclude 11kV interconnection which prevents the provision of an 11kV alternative for load transfer to the 33kV supply from the zone substations. In the remaining urban areas there is a higher degree of meshing or interconnection between 11kV feeders where possible, although transformer loadings rather than distance tends to limit the ability to back-feed on the 11kV. OtagoNet has a small amount of underground distribution cable in these areas, mainly around newer housing and in special circumstances to avoid clearance issues.

The network construction is largely similar in the remaining urban areas, with the main differences being closer pole spacing in towns, under-built LV and larger transformers that are often ground-mounted in the towns. OtagoNet also has remote and rugged areas that are serviced, sometimes at considerable extra cost, even for similar line types, due to increased travel times and specialised vehicles required to install poles in rugged terrain. Some of the worst areas require extensive use of helicopter and tracked vehicles. Line rebuild standards use concrete poles and hardwood crossarms to ensure long lives.

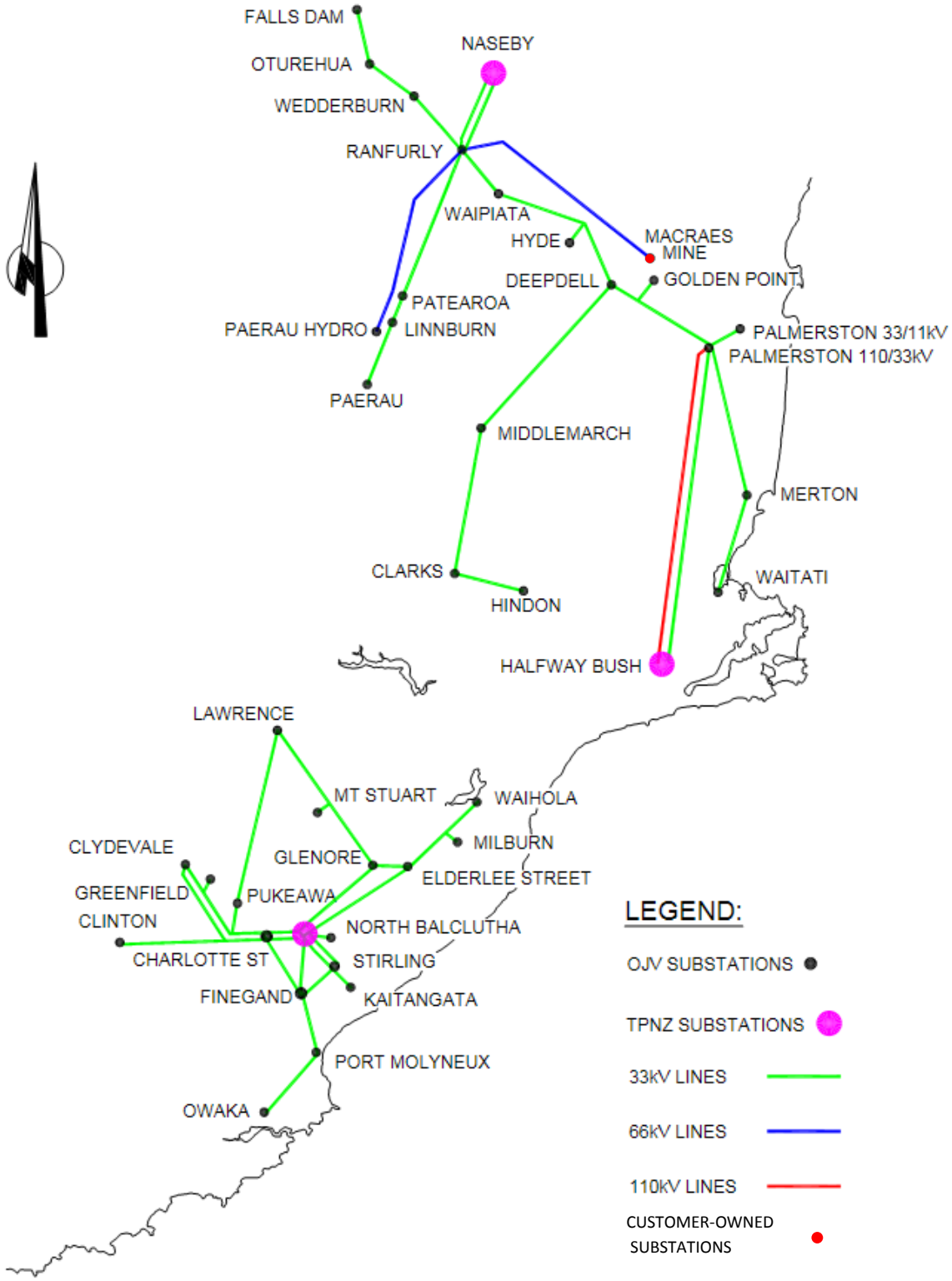

Figure 9: Subtransmission Network

Table 8: OJV's Zone Substations

Substation	Nature of load	Description of substation	Supply security
Charlotte Street (Balclutha)	Urban domestic and commercial with some rural loads including farms and timber mills	Dual 33kV supply to a 33kV indoor switchboard, with three 33kV feeders. Dual 5MVA transformers, 11kV indoor switchboard	No loss of supply after first contingent event (N-1)
Clarks	Remote isolated rural farms	Tee off the 33kV radial line beyond Middlemarch. 0.5MVA 22kV SWER substation.	Load restored in time taken for repair of first contingent event (N)
Clinton	Small urban township and rural farms	Radial 33kV from Clifton switches. 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Clydevale	Small urban township and rural farms	Alternate 33kV lines supplying 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Deepdell	Remote isolated rural farms	Alternate 33kV lines supplying 0.75MVA transformer and basic 11kV outdoor substation.	Load restored in time taken for repair of first contingent event (N)
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 11kV indoor switchboard.	No loss of supply after first contingent event (N-1)
Finegand	Rural farming Meat processing plant	Three supply routes at 33kV. 2.5MVA transformer and outdoor 11kV substation. A 33kV feed to Processing plant.	Load restored in time taken for repair of first contingent event (N)
Glenore	Rural farming	Supplied off a 33kV ring. 1.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Golden Point	Mining	Teed off the Deepdell to Palmerston 33kV line. 5MVA transformer with indoor 11kV switchgear.	Load restored in time taken for repair of first contingent event (N)
Hindon	Remote isolated rural farms	Radial 33kV line to 0.5MVA 22kV SWER and 0.1MVA 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Hyde	Rural farming with irrigation load	Alternate 33kV line to a 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Kaitangata	Small urban township and rural farms	Radial 33kV to a 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken to isolate and back-feed after first contingent event (N)
Lawrence	Small urban township and rural farms	Alternate 33kV lines to a 2.5MVA transformer and indoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Linnburn	Rural farming with irrigation	Temporary substation teed off radial 33kV line to Paerau. 1 MVA transformer and single feeder.	Load restored in time taken for repair of first contingent event (N)
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.	Load restored in time taken for repair of first contingent event (N)
Middlemarch	Small urban township and rural farms	Radial 33kV from Deepdell to 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Milburn	Sawmills and some rural load transferred off Milton and Waihola	Teed off the Elderlee to Waihola 33kV line. One 3/5MVA transformer and one 2.5MVA transformer with indoor 11kV switchgear.	Load restored within 25 minutes after first contingent event (N)
North Balclutha	Urban domestic and commercial with some rural	33kV line from Balclutha GXP. 5MVA transformer and outdoor 11kV substation.	Load restored in time taken to isolate and back-feed after first contingent event (N)

Substation	Nature of load	Description of substation	Supply security
Oturehua	Rural farming	Teed off the radial 33kV from Ranfurly to Falls Dam. 0.75MVA transformer, outdoor 11kV substation and 33kV regulator for generator connection.	Load restored in time taken for repair of first contingent event (N)
Owaka	Small urban township and rural farms	Radial 33kV line from Finegand. 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Paerau	Remote isolated rural farms and irrigation	Radial 33kV from Ranfurly. 1MVA transformer and basic 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Paerau Hydro	12.25MW hydro generation station	Radial 66kV line from Ranfurly. Dual 7.5M/15VA 66/11kV transformers with 66kV switchyard and indoor 11kV board.	Load restored in time taken for repair of first contingent event (N)
Palmerston	Urban domestic and commercial with some rural farms and timber mills	Radial 33kV to dual 2.5MVA transformers and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
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.	Load restored in time taken for repair of first contingent event (N)
Port Molyneux	Small seaside township and rural farms	Teed off radial 33kV line to Owaka. 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Pukeawa	Rural farming	Alternate 33kV lines to a 0.75MVA transformer and basic 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Ranfurly	Urban domestic and commercial with some rural farms and irrigation 33/66kV step-up and switching station	Dual heavy 33kV lines from Naseby GXP to dual 2.5MVA transformers and outdoor 11kV substation. Dual 12.5/25MVA 33/66kV transformers, 33 and 66kV outdoor substations.	No loss of supply after first contingent event (N-1) for 66/33 loads. Other load restored within 25 minutes after first contingent event (N)
Remarkables	Urban domestic and commercial	Dual 33 kV cables from Frankton GXP to dual 12.5/23 MVA transformers and indoor 22 kV switchroom.	No loss of supply after first contingent event (N-1)
Stirling	Fonterra Stirling Cheese Factory	33kV line and cable switch-able between two 33kV lines from Balclutha GXP. 5MVA transformer and 11kV indoor switchboard.	Load restored in time taken for repair of first contingent event (N)
Waihola	Small urban township and rural farms	Radial 33kV line off the 33kV Ring that supplies Elderlee St and Glenore. 1.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Waipiata	Rural farming with irrigation	33kV tee off the 33kV line from Ranfurly to Deepdell. 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Waitati	Small urban townships and rural farms	Radial 33kV line from Palmerston to a 2.5MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)
Wedderburn	Rural farming	Teed off the 33kV line from Ranfurly to Falls Dam. 1MVA transformer and outdoor 11kV substation.	Load restored in time taken for repair of first contingent event (N)

The network includes 924 km of Single Wire Earth Return (SWER) lines. This is a cheaper form of line construction suitable for feeding small loads at the fringes of the network. Regulatory requirements limit the impact on affected telecommunications circuits which generally requires the high voltage current on this line construction to 8 amps or less. As load requirements increase, SWER lines are progressively replaced with the more normal 2-phase and 3-phase line construction.

OJV's split of distribution network on a per substation basis is presented in Table 12. Safety and reliability are OJV's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

2.2.5. Distribution Substations

Just as zone substation transformers form the interface between OJV's subtransmission and distribution networks, distribution transformers form the interface between OJV's distribution (22/11 kV) and LV (400/230 V) networks. OJV's distribution substations range from single-phase 1 kVA pole-mounted transformers with only minimal fuse protection to three-phase 1,500 kVA ground-mounted transformers that are dedicated to single customers. Table 13 shows distribution transformer numbers by rating.

2.2.6. Low Voltage Network

The Frankton/Lake Hayes 230/400V Low Voltage (LV) network consists of clusters of underground cable at each of the main developments supplied by OJV. The LV network in the Shotover Country development has a moderate degree of interconnection that enables many customer connections to be supplied from "either end" in the event of a transformer failure. Transformer loading and volt drop tend to be the limiting factors in utilising these backups.

The remaining OtagoNet LV networks are predominantly clustered around each distribution transformer. The coverage of each individual LV network tends to be limited by volt-drop to a radius of about 200 m from each transformer. These networks are almost solely radial with minimal meshing, even in urban areas, because of excessive volt-drop which would otherwise occur in the long conductors.

Construction of OJV's LV network varies considerably and can include the following configurations:

- Overhead LV only.
- LV under-built on 11 kV.
- XLPE or PVC cable (relatively rare outside Frankton and the Balclutha CBD).

2.2.7. Customer Connection Assets

OJV has 15,131 customer connections - for which revenue is earned for providing a connection to the network via the twelve retailers which convey electricity over the network. All of the "other assets" convey energy to these customer connections and essentially are a cost to OJV that has to be matched by the revenue derived from the customer connections. These 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. The number of connections and changes over the year are shown in Table 9.

Table 9: Classes of Customer Connections

	Small (<=20 kVA)				Medium (21-99 kVA)			Large (>=100 kVA)				
	<=15 kVA 1ph	Low User	15 kVA 3 ph	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	1/2 hr metered individual	Total
Apr-14	7980	3450	2737	76	190	316	71	47	15	9	77	14968
May-14	7988	3451	2744	76	187	319	71	46	16	9	78	14985
Jun-14	7986	3453	2743	80	186	318	71	46	16	9	78	14986
Jul-14	7936	3503	2743	80	176	283	103	56	19	9	78	14986
Aug-14	7920	3530	2739	80	184	319	71	45	15	9	79	14991
Sep-14	7872	3600	2733	81	186	319	70	45	15	9	80	15010
Oct-14	7824	3673	2730	80	188	323	72	45	15	9	81	15040
Nov-14	7836	3676	2732	79	189	325	74	44	14	9	82	15060
Dec-14	7830	3709	2732	79	191	326	75	45	14	9	83	15093
Jan-15	7384	4166	2732	79	191	327	76	45	14	9	84	15107
Feb-15	7355	4197	2724	78	189	329	74	44	14	9	86	15099
Mar-15	7392	4194	2718	78	190	328	77	45	14	9	86	15131

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.

OJV has a range of other assets to provide control or other auxiliary functions as described in Table 10.

Table 10: OJV's Other Assets

Load Control Assets	
Ripple Injection Plant and Receivers	OJV currently owns and operates ripple injection plants at Balclutha, Palmerston and Ranfurly. Ripple relays at the customer's premises respond to the injected ripple signal and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network. The ripple function in the Frankton area is provided by Delta Utility Services Limited under a service arrangement.
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 more recent equipment also includes voltage, frequency, directional and circuit breaker fail functionality in addition to the basic functions. For overhead networks a reclose function can be used to restore power immediately after self-clearing faults. 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 a simple over-current device 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. Switches may be able to break 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 so provide 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 (VRR's) provide automatic control of the 'Tap Change On Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.
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. OJV's 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.
Communication Media	OJV currently owns and operates a UHF radio network between 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 several distribution line reclosers to the SCADA master. A VHF Radio telephone repeater network is also used for communications between mobile field staff, depots, and System Control.
Remote Terminal Units	OtagoNet's SCADA system was installed in 2000 with computer and software updates on a regular basis to keep the system fully up to date with the manufacturer's latest version. When the new OtagoNet SCADA system was installed, most communications links were also updated.
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 450kW, 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.
Metering	Time-of-use (TOU) meters have not been installed at any of the 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.

2.3. Network Asset Details

2.3.1. Assets Installed at Non-OtagoNet Bulk Electricity Supply Points

OtagoNet owns assets at four Transpower-owned GXPs, and on easements near the Mt Stuart and Paerau Hydro sites. There are no OtagoNet assets installed at Falls Dam. The assets involved are:

- **Balclutha, Naseby, Halfway Bush GXPs:** Each site has an OtagoNet-owned SCADA terminal connected to the Transpower-owned RTU; Balclutha and Naseby also have an OtagoNet check meter.
- **Frankton GXP:** Communications equipment enabling operational control of the dedicated 33 kV circuit breakers.
- **Paerau Hydro:** All substation assets at this site are owned by OtagoNet.
- **Mount Stuart:** OtagoNet owns an outdoor bus with metering unit, relays, and a 33kV CB protecting customer-owned cable. This equipment is physically located on private land approx. 1km from the wind farm.

2.3.2. Subtransmission Network

Subtransmission Lines

Pole overhead lines form the majority of subtransmission circuits within rural Otago. These consist of unregulated 33kV or 66kV circuits of a capacity specifically chosen for the anticipated load. The dominant design parameters are voltage drop and losses. Almost exclusively the current loading is well below the thermal capacity of the conductor. Voltage drop is a problem due to the small conductor size and long circuit lengths. 33 kV regulators are needed on the OtagoNet system partly because 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 recent legislation. Poles are a mixture 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.

Figure 10 and Figure 11 summarise the length and commissioning date of the subtransmission network poles and conductor respectively. Since most transmission circuits are of overhead line construction these graphs gives a good indication of overall circuit ages. Note however that many circuits have poles and other hardware replaced as and when needed; so the age of a circuit is not necessarily the age of individual components within that circuit.

There are a large number of poles past their standard life although environmental conditions in the OtagoNet area are generally very good, with excellent wood pole life in the Maniototo. Five-yearly walking condition inspections are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

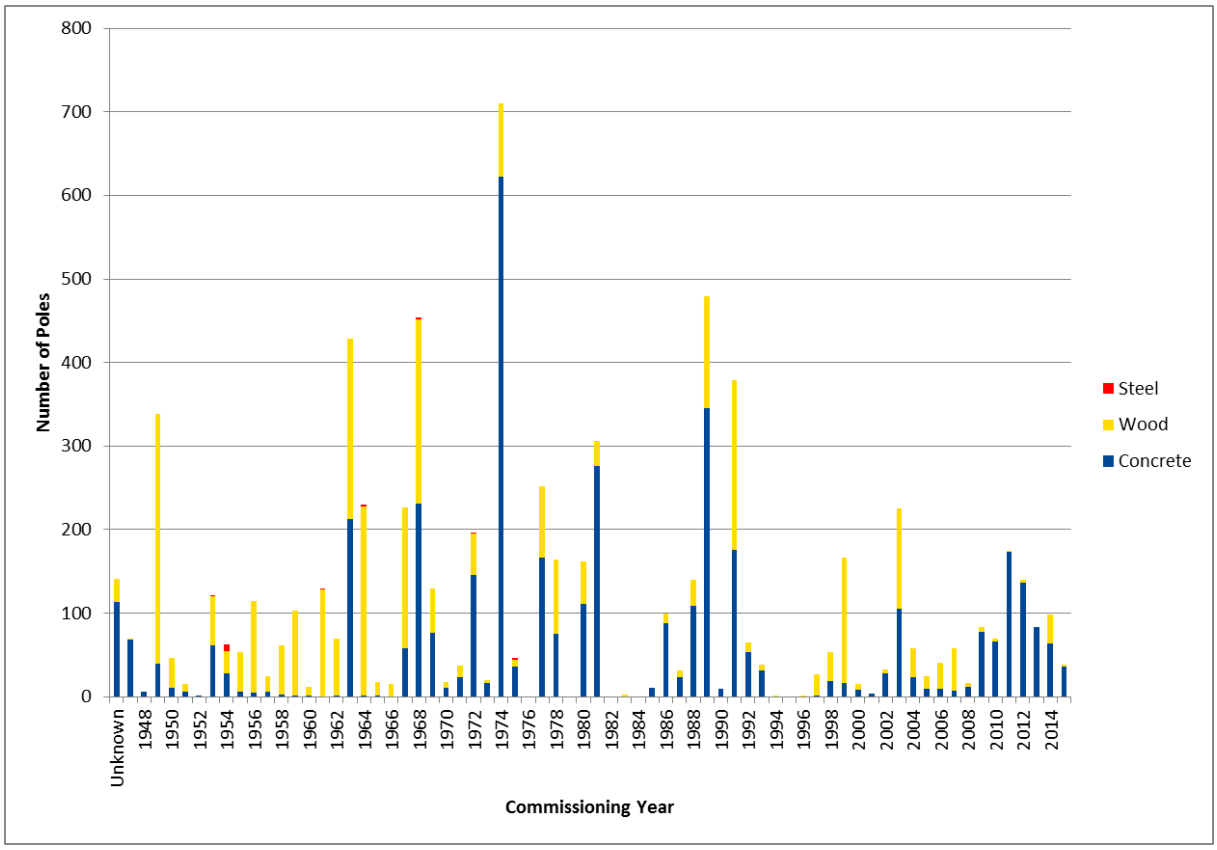

Figure 10: Subtransmission Poles

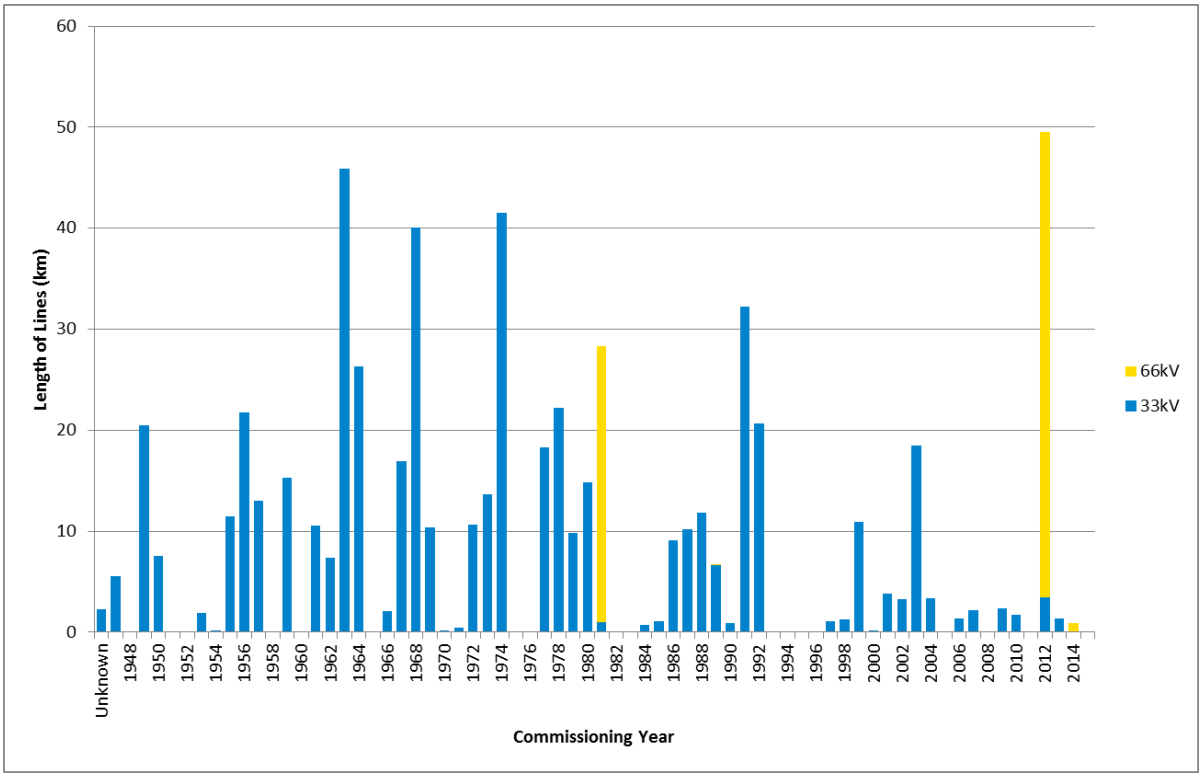

Figure 11: Subtransmission Conductor

Subtransmission Cables

The Otago network subtransmission cable network consists of:

- 240mm² AL XLPE installed in 1977 near the Balclutha sub, due overhead line congestion
- 95mm² AL XLPE installed in 1997 and 2007 at Charlotte Street, due overhead line congestion
- 95mm^2 AL XLPE installed 2003/4 on the Patearoa 33kV line to bypass an irrigation system
- 300 mm^2 AL XLPE installed in 2009 to supply the Remarkables substation at Frankton.

The cables are sized well for the connected substations and are in good condition. Earlier XLPE cables are understood to have a slightly shorter life expectancy however the oldest of these cables is still expected to have a remaining life beyond the 10 year planning horizon.

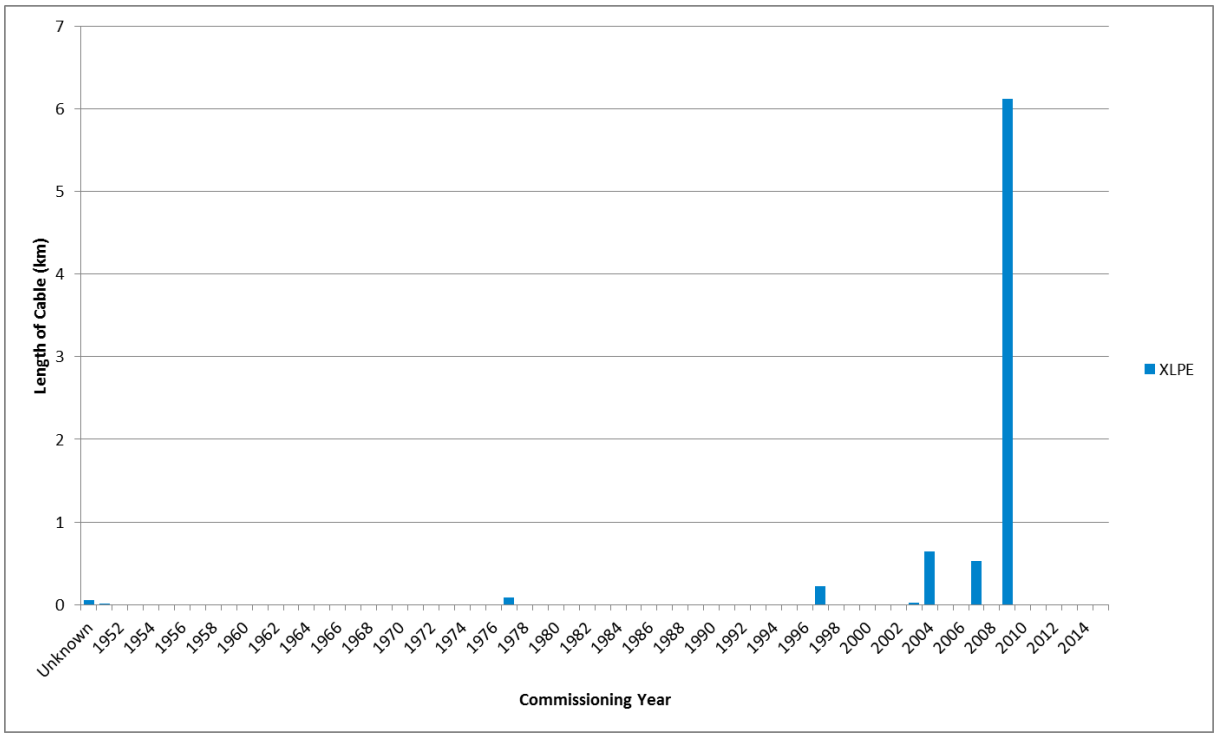

Figure 12: Subtransmission Cables

2.3.3. Zone Substations

Switchgear

Charlotte St 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.

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.

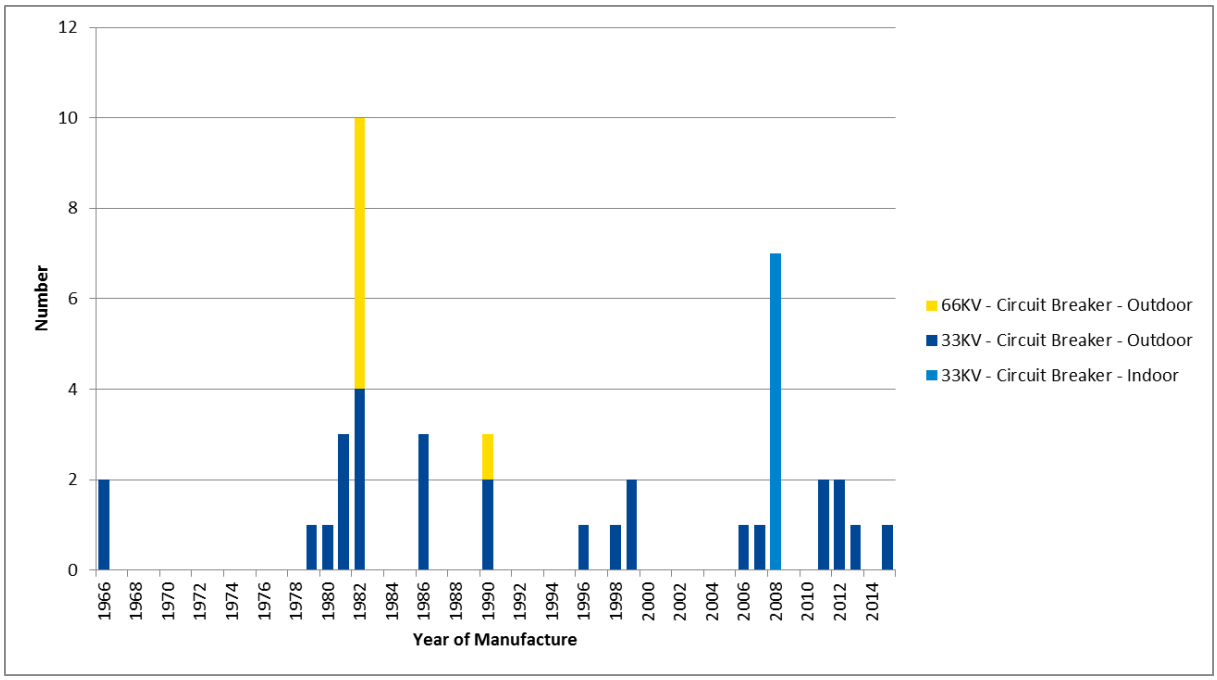

Figure 13: Subtransmission Voltage Circuit Breakers

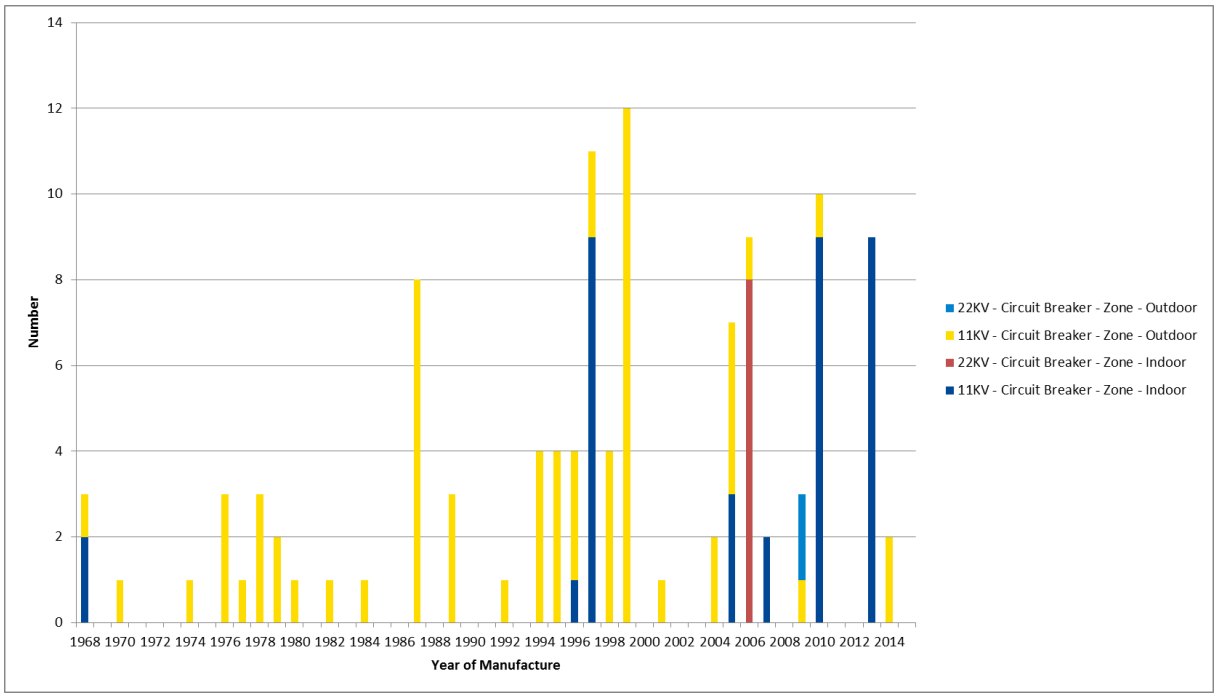

Figure 14: Substation Distribution-Voltage Circuit Breakers

Circuit breakers are considered to deteriorate in a time based fashion with regard to general corrosion and mechanical faults. Experienced has indicated that circuit breakers with oil based arc quenching require significant maintenance following relatively few fault clearing operations.

Literature and manufacturer recommendations suggest that vacuum and SF_6 devices are not affected so severely by fault breaking current.

Consequently routine maintenance is carried out at two yearly intervals for oil-based circuit breakers and five yearly intervals for vacuum and SF_6. Some circuit breakers are maintained following a specific number of operations. Routine substation inspections are used to check for corrosion, external damage and the like.

Power Transformers

OJV power transformers vary significantly in both size and detail. They range from the 12.5/25MVA 33/66kV three phase units complete with On Load Tap Changers (OLTC) at Ranfurly to simple 750kVA fixed tap transformers at rural substations. A bank of 110/33 kV transformers in the Palmerston area was recently purchased from Transpower.

Peak load in predominantly urban substations generally occurs at the coldest times when heating requirements are greatest; on solely rural substations with large amounts of irrigation/dairy load, the peak load occurs in the summer.

Each unit is under its ONAN rating, and Dissolved Gas Analysis monitoring shows that each is in acceptable condition, with the exception of the Palmerston 110/33 kV transformers which will be made redundant by the Halfway Bush-Palmerston 110/33 kV line conversion scheduled for 2018. There are however a number of power and regulator transformers that are past nominal life and will be replaced within the planning period.

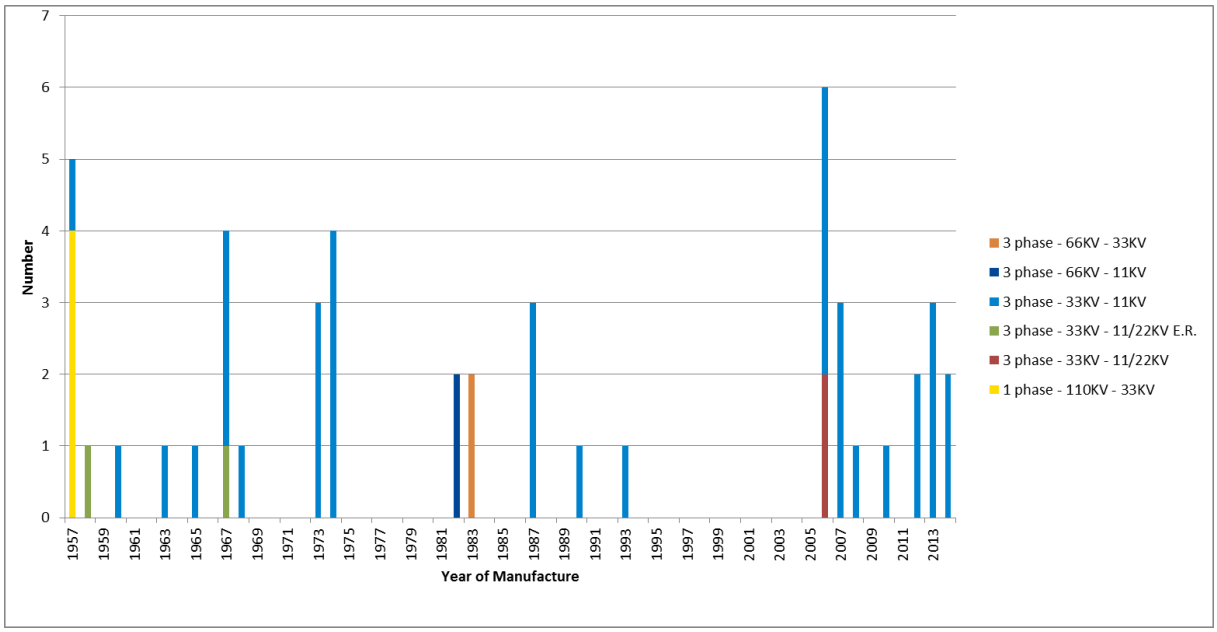

Figure 15: Power Transformers

There are also a number of regulator transformers that are used to help maintain voltage over the long lines typical of the low-density OtagoNet network. 33 kV regulators are generally located at substation sites, and a few 11 kV regulators are installed at some of the smaller substations in place of an on-load tap changer. The oldest of these regulators at Oturehua is undergoing replacement. The remaining 11 kV regulators are installed in the field to maintain voltage on the distribution network and are generally in acceptable condition; details are as shown in Table 11.

Table 11: Distribution Voltage Regulators

Location	Purpose
Balmoral	33/0.4kV regulation of a low voltage for the local water scheme
Clifton	Regulation of a single wire 11kV circuit 10km from Clinton zone substation feeding a rural community.
Craigallachie	11kV regulation at a point 14km from Lawrence zone substation for a further 15km of line to Beaumont.
Craiglynn	Regulation of a single wire 11kV circuit from a small 33/11kV isolating transformer feeding a small remote community.
Dunrobin Rd	11kV regulation at a point 19km from Palmerston zone substation for a further 20km of line to Morrisons.
Glenpark	11kV regulation at a point 7km from Palmerston zone substation for a further 12km of line to Dunrobin Road regulator.
Kokonga	11kV regulation at a point 8km from Waipiata zone substation for a further 10km of line to Kyeburn.
Lower Gimmerburn	11kV regulation at a point 7km from Ranfurly zone substation for a further 13km of line to Lower Gimmerburn.
Mahinerangi	Regulation of a single wire 11kV circuit from a small isolating transformer feeding a small remote community.
Naseby	11kV regulation for a large holiday destination 11km from Ranfurly zone substation.
Popotunoa	11kV regulation at a point 7km from Clydevale zone substation for a further 16km of line to Popotunoa and Rankleburn.
Redbank	Regulation of a single wire 11kV circuit from a small 33/11kV isolating transformer feeding a small remote community.
Stoneburn	Regulation of a single wire 11kV circuit from a small 33/11kV isolating transformer feeding a small remote community.
Tahakopa	11kV regulation at a point 18km from Owaka zone substation for a popular holiday destination and a further 25km of line into the Chaslands.

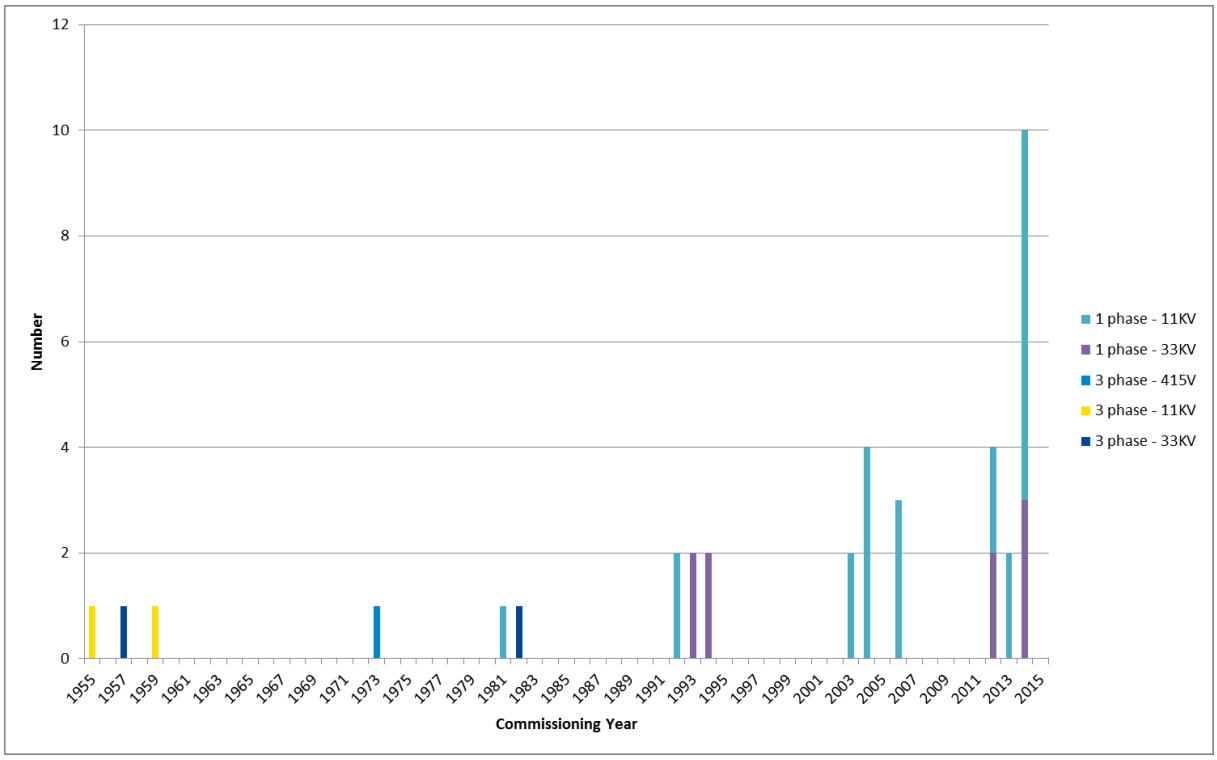

Figure 16: Regulator Transformers

2.3.4. Distribution Network

Table 12 shows the split of the distribution network on a per zone substation basis.

Overhead Network

Overhead lines form the backbone of the rural networks and account for the largest proportion of rural network costs and interference to customer supply.

Construction of electrical distribution within Otago commenced around 1923. Most construction was undertaken in the 1930's and then in the 1950's and 1960's, with extensions in the 1970's and 1980's extensions were generally to transmit larger levels of energy into the existing reticulated areas.

The makeup of OJV's network varies in accordance with these timeframes. Most construction in the 1930's utilised hardwood poles because of their availability and strength. Concrete poles became prevalent in the 1950's. From 1991 to 2008 softwood poles were introduced based on cost and strength. New concrete poles became the standard from 2008.

The nominal life of poles varies with pole type: 45 years for wood poles and 60 years for concrete. Experience has shown however that hardwood poles last substantially longer under the conditions found on much of the OJV network. Replacement and renewal is carried out on a condition basis based on five yearly inspections.

Table 12: Distribution network per substation

Substation	Line Length (km)	Underground Cable (km)	Customers	Customer Density (per km)
Charlotte Street	72.05	1.08	1505	20.58
Clarks	134.41	-	155	1.15
Clinton	290.22	1.6	687	2.35
Clydevale	289.35	1.21	574	1.98
Deepdell	54.19	0.3	78	1.43
Elderlee Street	150.78	1.51	1407	9.24
Finegand	103.43	0.72	276	2.65
Glenore	94.46	0.03	185	1.96
Golden Point	-	-	-	-
Hindon	117.57	-	123	1.05
Hyde	38.15	0.01	56	1.47
Kaitangata	99.75	0.02	556	5.57
Lawrence	176.56	0.13	656	3.71
Linnburn	29.08	1.01	42	1.40
Merton	125.73	2.26	1318	10.30
Middlemarch	120.13	0.7	313	2.59
Milburn	40.46	0.69	100	2.43
North Balclutha	121.44	0.34	1176	9.66
Oturehua	28.62	-	81	2.83
Owaka	285.1	1.72	838	2.92
Paerau	27.06	-	36	1.33
Paerau Hydro	9.78	-	1	0.10
Palmerston	171	1.12	953	5.54
Patearoa	49.28	2.37	141	2.73
Port Molyneux	37.01	0.16	365	9.82
Pukeawa	43.5	0.51	68	1.55
Ranfurly	203.3	4.12	1086	5.24
Remarkables	-	20.91	538	25.73
Stirling	-	1.08	1	0.93
Waihola	93.33	0.97	564	5.98
Waipiata	82.24	0.81	168	2.02
Waitati	67.83	5.47	951	12.97
Wedderburn	35.55	-	44	1.24
Unallocated	72.6	1.32	85	-

Figure 17 shows the age and length of distribution conductor on the network, while Figure 18 shows the number and age of poles supporting the distribution lines on the network. The wooden poles used for the 15 years to end 2008 are predominantly CCA treated softwoods, while a small number of recent wooden poles will be traditional hardwood where the additional strength is required. The majority of poles since late 2008 are the 11m standard Busck concrete pole.

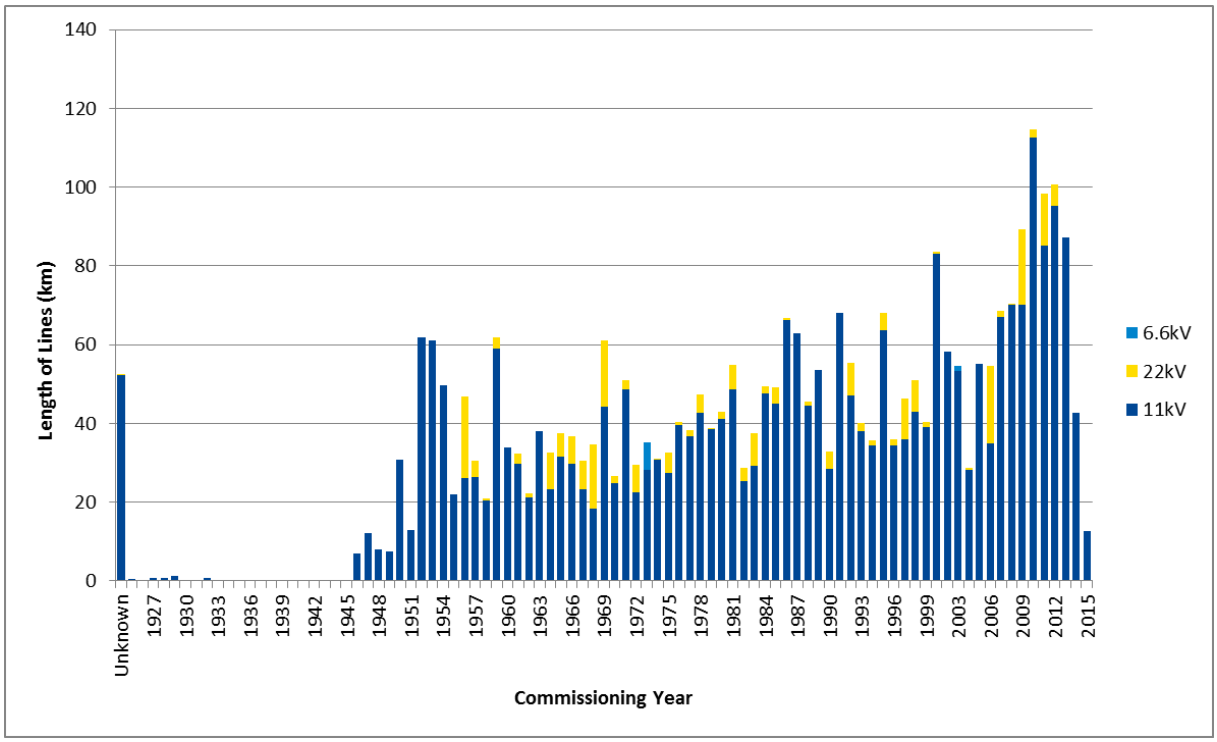

Figure 17: Distribution Conductor

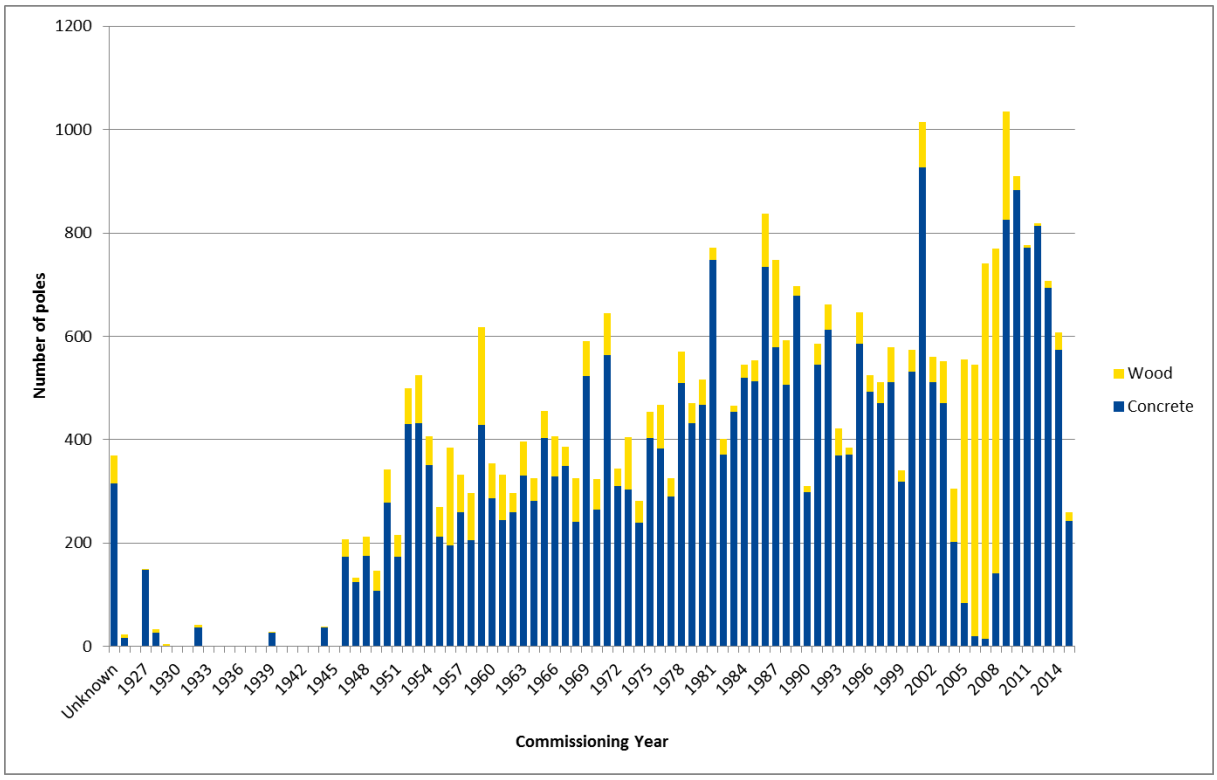

Figure 18: Distribution Poles

Overhead Switchgear

OJV has a number of 11 kV outdoor circuit breakers installed on the distribution network to help improve reliability. These numbers will increase over the next few years as a Quality of Supply project focuses on areas where circuit breaker installation will offer the most benefit.

In addition there are approximately 300 Air Break Switches on the network, together with around 10,000 individual 11 kV fuses. These items are visually inspected as part of routine line inspections. "Hot-spot" thermographic testing may be carried out where there is reason to believe a switch might not be contacting properly.

The distribution field circuit breaker age profile is shown in Figure 19, with the oldest unit installed in 1976. Maintenance practices are similar to those for substation circuit breakers.

Underground Network

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

Failure of cable is very rare. The most common failure modes are joints, terminations, lightning and external mechanical damage. Consequently little proactive maintenance is deemed necessary on the cables themselves. The distribution cable age profile is shown in Figure 20.

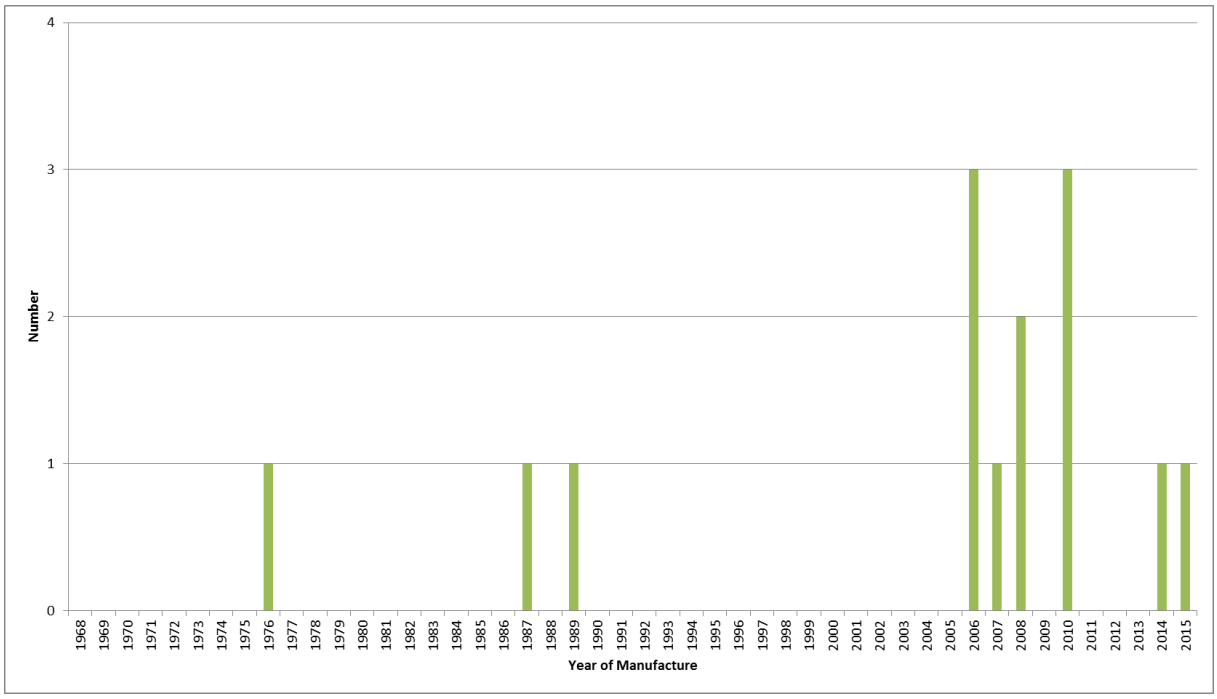

Figure 19: Distribution Circuit Breakers

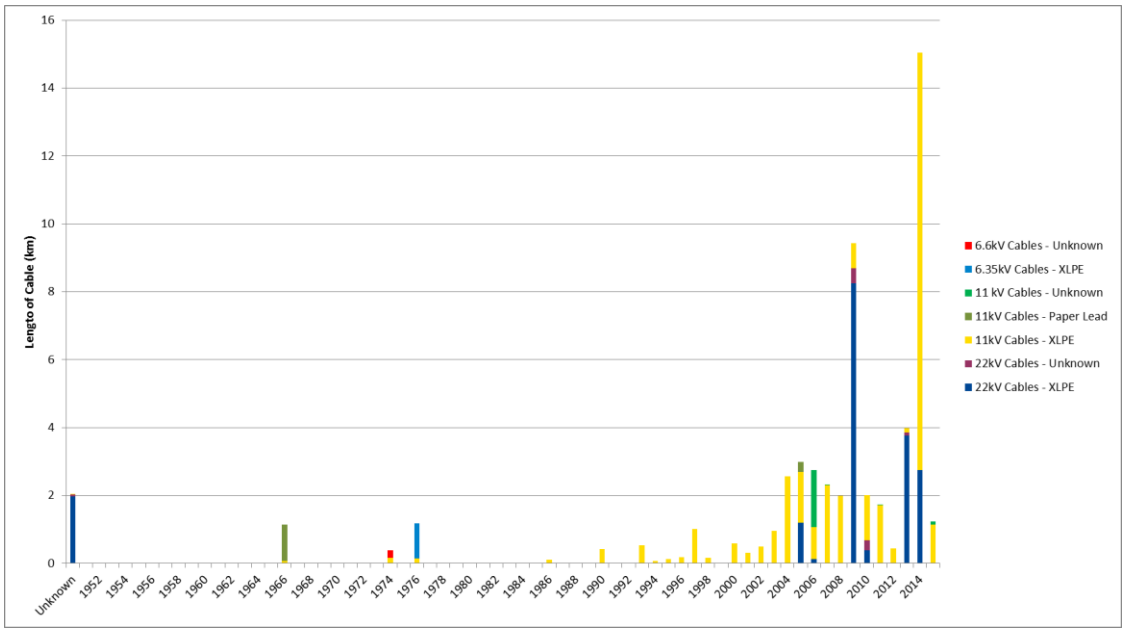

Figure 20: Distribution Cables

Ground-mount Switchgear

Most of the ground-mount switchgear owned by OJV is the Ring Main Units (RMUs) tying together the distribution cables of the Frankton network. In addition there are RMUs in the OtagoNet area in 10 locations where they are associated with specific transformers.

RMUs require little maintenance, and these assets are relatively new compared to their nominal life of 45 years. The age profile for OJV RMUs is shown in Figure 21.

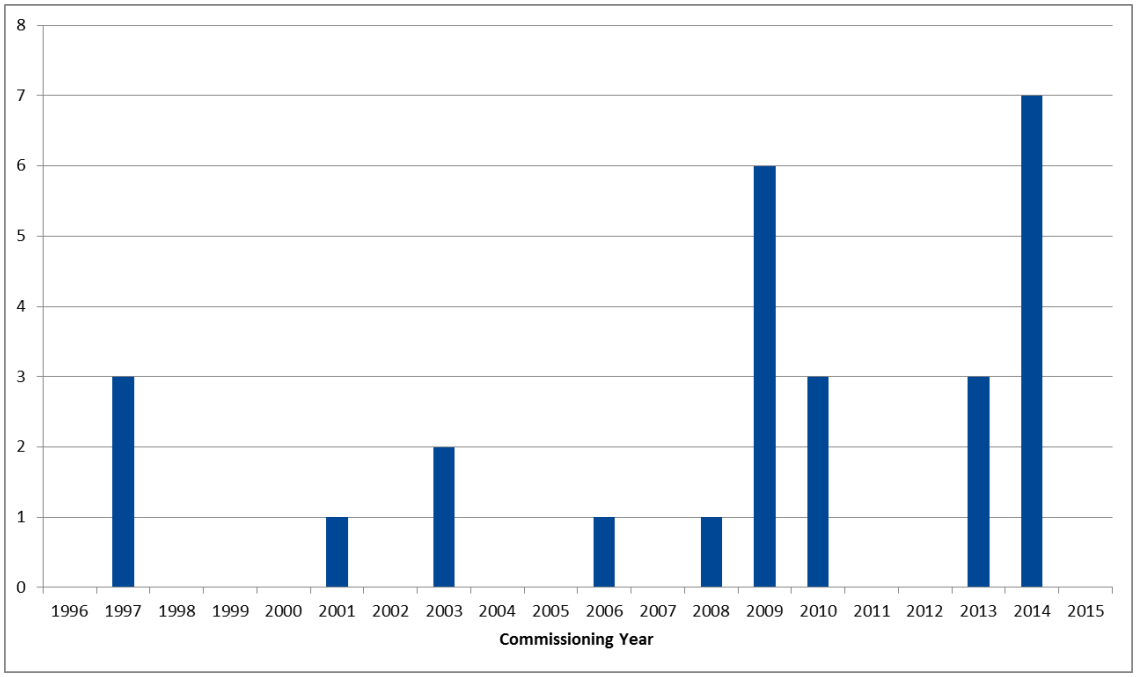

Figure 21: Ring Main Units

2.3.5. Distribution Substations

Transformers

The majority of OJV's rural transformers supply one or two customers in close proximity. Since many of these rural properties are spaced kilometres apart, the number of individual transformers requires to supply the customer base is higher than for more densely populated networks. The most common rural transformer sizes are 10kVA to 30kVA, pole mounted on the overhead network.

The most economic electrical supply arrangement typically tends to have around 50 domestic customers connected via LV circuits to a single common transformer. Consequently the most common urban transformer ratings are 200kVA to 300kVA.

Table 13 shows the numbers of the various sized distribution transformers on OJV's network, and their age profile is displayed in Figure 22.

Table 13: Number of distribution substations

Phases	Rating	Pole Mount	Ground Mount
1 phase:	15 kVA and smaller	2627	4
	30 kVA	424	3
	50 kVA	107	5
	75 kVA	1	0
	100 kVA	9	0
	200 kVA	3	0
3 phase:	15 kVA and smaller	195	2
	30 kVA	184	3
	50 kVA	268	4
	75 kVA	47	1
	100 kVA	90	7
	150 kVA	24	2
	200 kVA	57	28
	250 kVA	28	10
	300 kVA	7	34
	500 kVA	6	45
	750 kVA	4	7
	1000 kVA	0	8
	1500 kVA	0	1

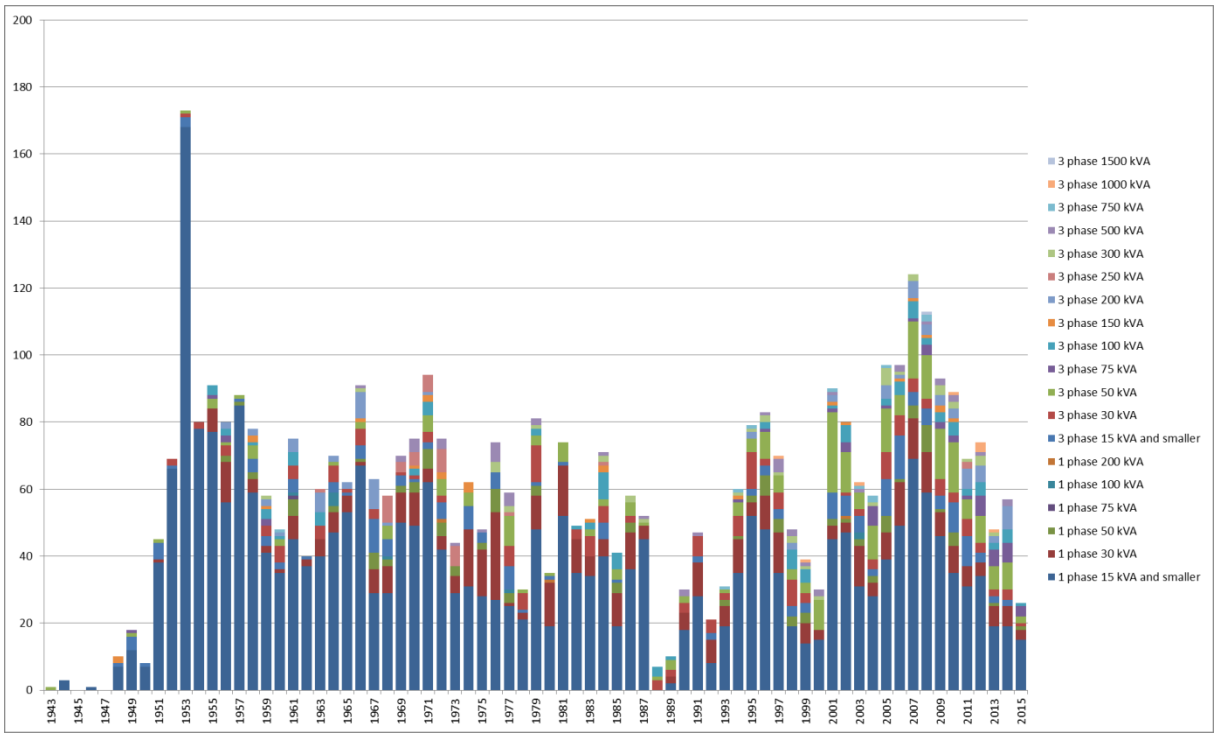

Figure 22: Distribution Transformers

Transformers found to be in poor condition during the five-yearly line inspections may be replaced with units removed from service and refurbished for reuse, if economic. As ground mounted units are typically enclosed, the weather impact is reduced and the condition of these transformers is generally good.

2.3.6. Low Voltage (LV) Network

The split of the LV network is shown on a per zone substation basis in Table 14.

Overhead

The majority of original reticulation circuits were of overhead construction, similar to 11kV distribution circuits. Most were of a flat top construction with 2 to 5 wires. The conductor size was relatively small due to the typical loading of the time.

Most overhead reticulation is relatively old, because underground construction is often preferred for more recent builds in urban areas. LV systems are more tolerant of ambient conditions than distribution voltage systems due to the much lower voltage stress imposed. LV overhead lines are managed on a similar basis to distribution lines albeit with a lesser priority.

Information on the age profile of the LV lines is incomplete; however the data that does exist within the information system is shown in Figure 23 and Figure 24. Data gathering in conjunction with the inspection program is expected to improve this data over the coming years.

Table 14: LV network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer Density/km
Charlotte Street	27.71	3.4	1505	48.38
Clarks	0.85	0.3	155	134.78
Clinton	8.77	0.19	687	76.67
Clydevale	6.18	0.03	574	92.43
Deepdell	2.76	-	78	28.26
Elderlee Street	32.6	0.88	1407	42.03
Finegand	3.8	0.04	276	71.88
Glenore	1.33	0.49	185	101.65
Golden Point	-	-	1	-
Hindon	0.62	-	123	198.39
Hyde	1.34	-	56	41.79
Kaitangata	16.39	0.1	556	33.72
Lawrence	21.3	1.65	656	28.58
Linnburn	0.5	-	42	84.00
Merton	33.9	4.2	1318	34.59
Middlemarch	8	0.06	313	38.83
Milburn	2.04	0.16	100	45.45
North Balclutha	21.5	4.35	1176	45.49
Oturehua	0.98	0.08	81	76.42
Owaka	17.61	1.77	838	43.24
Paerau	-	-	36	-
Paerau Hydro	-	-	1	-
Palmerston	29.15	1.19	953	31.41
Patearoa	2.71	0.55	141	43.25
Port Molyneux	6.32	0.34	365	54.80
Pukeawa	-	-	68	
Ranfurly	24.76	2.15	1086	40.36
Remarkables	-	10.26	538	52.44
Stirling	-	-	1	-
Waihola	11.38	3.22	564	38.63
Waipiata	3.35	0.3	168	46.03
Waitati	27.03	4.97	951	29.72
Wedderburn	1.09	-	44	40.37
Unallocated	200.43	0.78	85	-

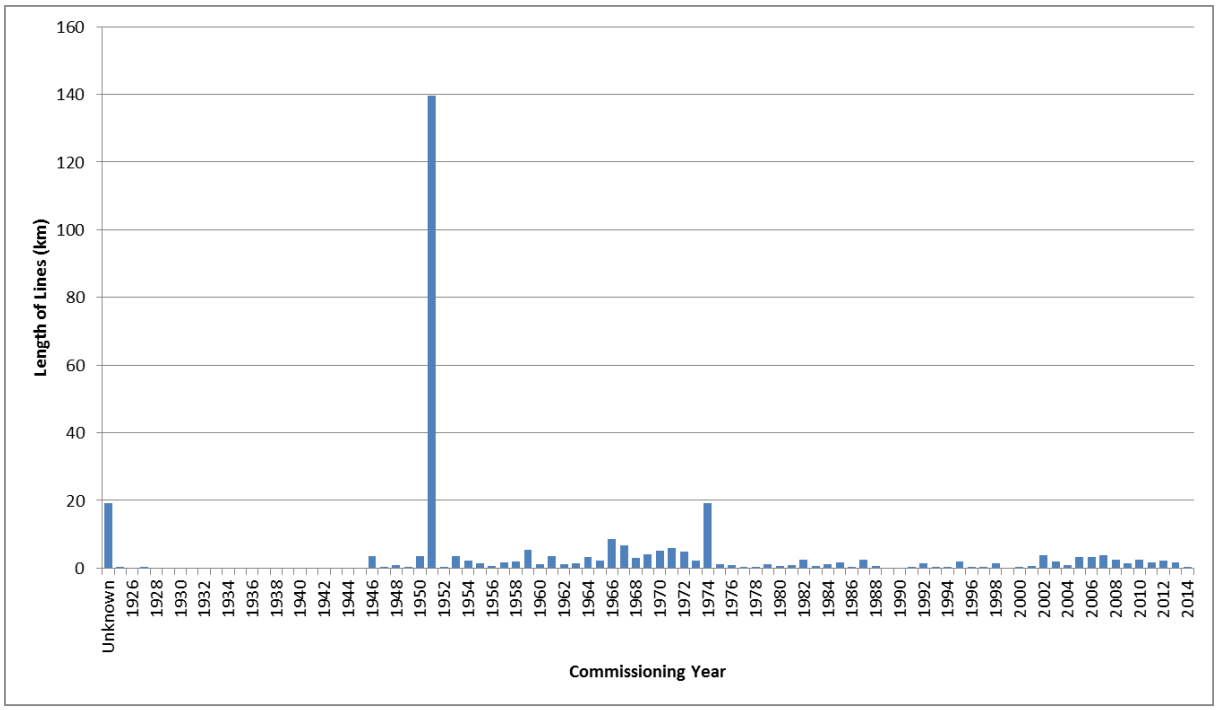

Figure 23: LV Lines

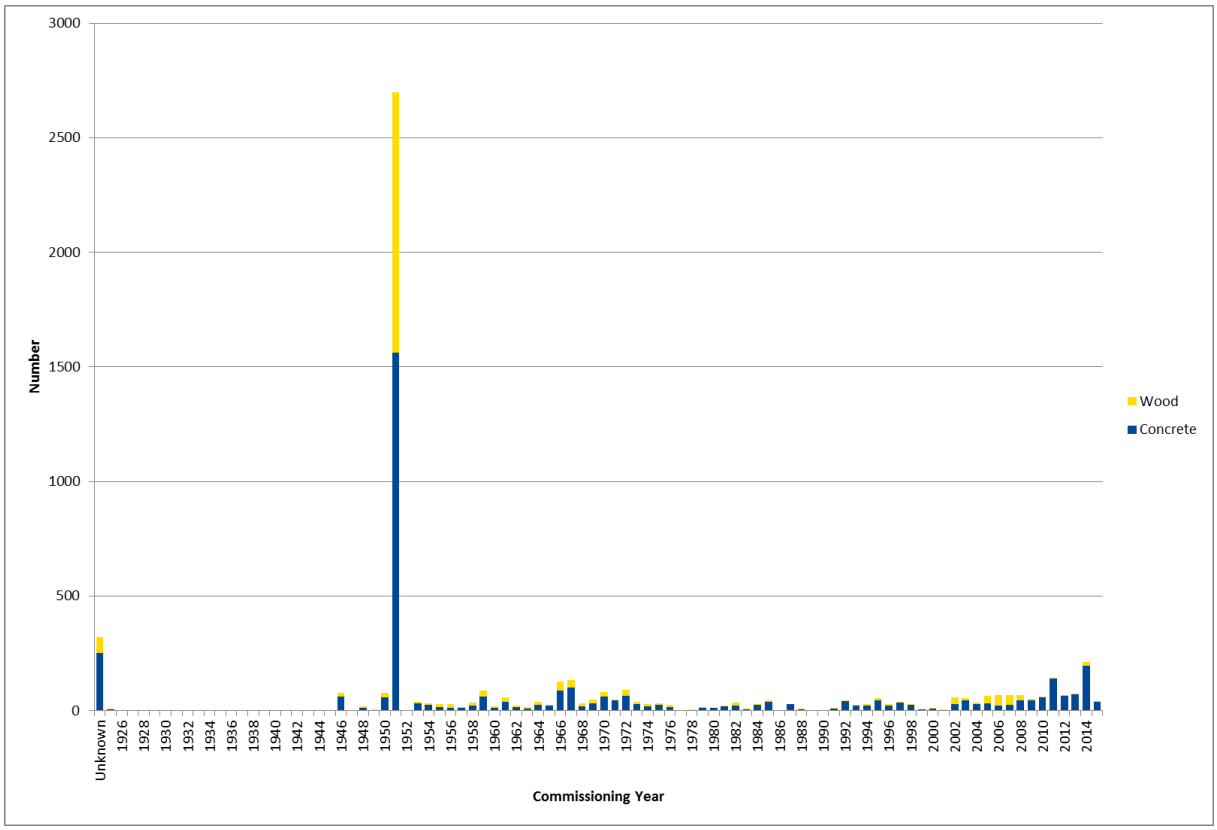

Figure 24: LV Poles

Underground

New reticulation in urban areas is now undertaken using cable circuits. Cable is generally aluminium conductor with a copper neutral screen. The dominant selection criterion is to limit voltage drop; typically cables are loaded to 30% of their current capacity, so thermal stresses on the cable are low.

Few problems are experienced with underground cable, with most faults occurring at joints or due to third-party mechanical damage. The age profile of the LV cable network is shown in Figure 25.

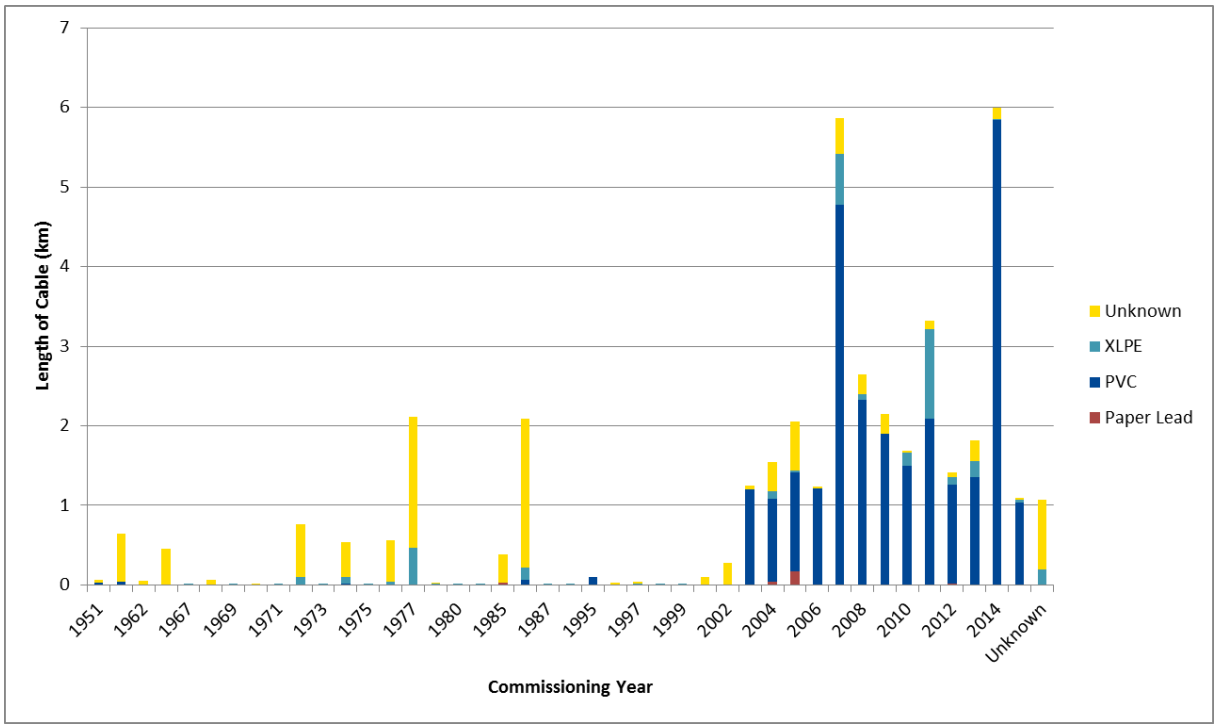

Figure 25: LV Cables

2.3.7. Other Assets

The injection plant at Balclutha is relatively new, and the electronic components of the other plants provide good service; however the coupling cells at Palmerston are at end of life. The converters at both Palmerston and Ranfurly are no longer supported, although spares are still available from the other PowerNet-managed networks.

If smart meters are adopted in the OtagoNet area they will make ripple injection plants redundant. If the adoption of smart meters does not take place in the near future, the Palmerston plant will be replaced with a new injection plant at Waikouaiti.

3. Service Levels

This section describes how OJV set its various service levels according to the safety, viability, quality, compliance and price objectives that are most important to stakeholders (see section 1.4). 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) vs desire for low price with good reliability, safety as first priority vs acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

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 describes those service levels in detail and how OJV justifies the service levels delivered to its stakeholders.

3.1. Customer Oriented Service Levels

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 and asking a predetermined set of questions; the full questionnaire used is detailed in Appendix 2. This is carried out independently by engaging Gary Nicol Associates who collate the results into a customer satisfaction report for presentation. Face to face interviews are also held directly with major customers to help understand individual service level requirements and satisfaction with current service levels.

Statistics around voltage 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. Customer engagement telephone surveys indicate that customers value continuity and restoration of supply more highly than other attributes such as answering the phone quickly, quick processing of new connection applications etc.

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.

3.1.1. 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.

This aligns 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 2026 are shown in Table 15 and take into account the recently updated default price-quality path calculation methodology, which includes new (lower) extreme event normalising boundaries, a 50% weighting for planned outages, and three benchmarks – Cap, Target, and Collar. The table also includes the effects of planned network developments that significantly influence reliability, and normalisation of major events.

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

Table 15: OJV Reliability Projections

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	…	2025/26
SAIDI	B (Planned)	74.0	74.0	74.0	74.0	74.0	…	74.0
	C (Unplanned)	169.9	164.7	160.8	156.8	154.8	…	134.7
	Total	**243.9**	**238.7**	**234.8**	**230.8**	**228.8**	**…**	**208.7**
SAIFI	B (Planned)	0.32	0.32	0.32	0.32	0.32	…	0.32
	C (Unplanned)	2.36	2.33	2.30	2.27	2.25	…	2.10
	Total	**2.68**	**2.65**	**2.62**	**2.59**	**2.57**	**…**	**2.42**

The underlying reliability for significant network areas and voltage levels can be broadly summarised as shown in Table 16. Customers in all market segments surveyed indicated a preference for paying about the same line charges to receive about the same level of supply reliability. This feedback supports OJV's strategy of prudence in capital investment, given that the low density of the network already imposes a high capital burden per ICP on OtagoNet's customers.

Table 16: 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

Table 17 shows 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 after normalising out extreme events and must not be breached more than once in any three year period. These values differ slightly from those shown in the 2015 Price-Quality Path Determination because the Frankton assets were not included in the calculations for that Determination; PowerNet has calculated revised values according to the process laid out in the Determination, but external audit of these values has not yet been completed.

Because of OJV's generally good reliability over the past five years, the SAIDI limit has been reduced by more than can be attributed to the new 50% weighting on planned work. This increases OJV's vulnerability to storm days by making it more likely that they will cause OJV to exceed its SAIDI limit.

Table 17: OJV Reliability Thresholds

	Target	Collar	Cap/Limit	Boundary
SAIDI	223.30	193.16	253.44	13.176
SAIFI	2.5071	2.1072	2.9069	0.1748

The Cap, Target and Collar benchmarks are used as part of a revenue incentive scheme for improving reliability on the network where cost effective. A total of $247,800 (equivalent to 1% of the starting price maximum allowable revenue for the regulatory period) is the "revenue at risk" for each of SAIDI and SAIFI.

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 of $123,900 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 of $123,900 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.

3.1.2. 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.
- 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 voltage complaints and the amount of notice before planned shutdowns. Table 18 sets out targets for these service levels for the next ten years (either as a percentage or on a scale of 1 to 5, where 1 is poor and 5 is excellent).

The use of Customer Satisfaction Surveys (questionnaires sent to customers with invoices for new connections) has been discontinued due to an extremely poor response rate. OJV is investigating alternative methods of gathering this information, including the possibility of adding similar questions to the existing Customer Engagement Survey (phone survey carried out by an independent consultant).

Table 18: Secondary service levels

Attribute	Measure	2016/17	2017/18	…	2025/26
Planned Outages	Provide sufficient information. {CES: Q5(a)}	>75%	>75%	…	>75%
	Satisfaction regarding amount of notice. {CES: Q5(c)}	>75%	>75%	…	>75%
	Acceptance of maximum of one planned outage every year. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES: Q4}	>50%	>50%	…	>50%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q6(b)}	>62%	>63%	…	>70%
	Information supplied was satisfactory. {CES: Q10(b)}	>62%	>63%	…	>70%
	OtagoNet first choice to contact for faults. {CES: Q10}	>35%	>37%	…	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<20	<20	…	<20
	Number of customers who have justified supply quality complaints {IK}	<15	<15	…	<15

{ } indicates information source: CES = Customer Engagement Survey, IK = Internal KPIs

3.1.3. Other Service Levels

In addition to the primary and secondary service levels that are of direct benefit to customers, there are a number of service levels that benefit other stakeholders; for example safety, amenity value, absence of electrical interference and performance data. 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 is expected to absorb the associated costs into its overall cost base.

Table 19: Other Service Levels

Service Level	Description
Safety	Various legal requirements require OJV's assets (and customer's plant) to adhere to certain 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	There are a number of Acts and other requirements that limit where OJV can adopt 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	Various statues and regulations require OJV to compile and disclose prescribed information to specified standards. These include: • Electricity Distribution Information Disclosure Determination 2012 • Commerce Act (Electricity Distribution Thresholds) Notice 2004
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 (NZECP36:1993). • Single wire earth return limitations (EEA High Voltage SWER Systems Guide). • NZCCPTS: coordination of power and telecommunications (several guides).

3.2. 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.

OJV is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution Information Disclosure Determination 2012. However previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008 which were in effect for disclosures up to and including 31 March 2012.

Listing and analysis is available on the Commerce Commission website and can be accessed at http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

3.2.1. Financial Efficiency Measures

OJV has redefined its financial efficiency measures to take advantage of the benchmarking opportunities available under the current Information Disclosure format. The new measures fall into two groups:

- Network OPEX metrics
- Non-Network OPEX metrics

to capture the level of efficiency in both sides of the business. However for effective benchmarking this OPEX must be measured against the relative size of the EDBs in question. As there is no single fair measure of the "size" of an EDB, OJV has adopted the most consistent (and therefore predictable) 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 therefore has six financial efficiency targets as shown in Table 20. Comparative benchmarking as discussed in section 3.4.2 shows these service levels to be in line with or ahead of peers once allowance is made for network size measures, therefore these levels are considered justified. It should be noted that allowance has been made for atypical network OPEX spend on the decommissioning of substations in the years ending 2020 and 2023.

Table 20: Financial Efficiency Targets

Measure	Network OPEX			Non-Network OPEX		
	/ICP	/km	/MVA	/ICP	/km	/MVA
2015/16	$250	$1000	$22500	$250	$1000	$22000
2016/17	$250	$1000	$22500	$250	$1000	$22000
2017/18	$250	$1000	$22500	$250	$1000	$22000
2018/19	$250	$1000	$22500	$250	$1000	$22000
2019/20	$500	$2000	$45000	$250	$1000	$22000
2020/21	$250	$1000	$22500	$250	$1000	$22000
2021/22	$250	$1000	$22500	$250	$1000	$22000
2022/23	$300	$1200	$27000	$250	$1000	$22000
2023/24	$250	$1000	$22500	$250	$1000	$22000
2024/25	$250	$1000	$22500	$250	$1000	$22000

3.2.2. Energy Delivery Efficiency Measures

Projected energy efficiency forecasts and targets are shown in Table 21. These measures are:

- 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].

Changes in peak management requirements have impacted the load factor. It may take a number of years for the Lower South Island (LSI) peak to settle down to a predictable level.

The loss ratio target was reduced recently due to a metering point shift for OJV's largest customer (responsible for approximately one third of OJV's electricity volume) that removed most of the losses involved in providing their power. Historically the loss ratio has varied due to reliance on annual sales quantities from retailers. As retailers are not reading the customers meter at midnight of the 31 December, some estimation methodology is required.

Table 21: Energy Efficiency Targets

Measure	2015/16	2016/17	…	2024/25
Load Factor	79%	79%	…	79%
Loss Ratio	5.0%	5.0%	…	5.0%
Capacity Utilisation	30%	30%	…	30%

3.3. Service Level Justification

OJV's service levels are justified when:

- Improvements provide positive cost benefit within revenue capability.
- Customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- Skilled labour and technical shortages constrain what can be achieved.
- 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.

Customer surveys over the last four years have indicated that customers' preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for increased supply reliability. However OJV does note the following issues:

- The default price path methodology requires no material decline in network reliability and now includes a revenue incentive for improving reliability.
- The "Safety" service level 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.

3.4. Basis for Service Level Targets

3.4.1. Historical Trends

When setting OJV's service level targets the recent history of these service level measures are taken into account and it is recognised that these measures will be difficult and typically slow to change. Historical results are trended and projected to forecast future service levels and then adjusted to account for any particular initiatives or other issues that are anticipated to affect service levels.

Targets for network reliability and for financial and energy efficiency targets are generally set at the forecast levels to help drive the completion of performance enhancement initiatives. Targets for customer satisfaction are set based on the desired outcome of achieving positive customer experiences while accepting that targeting 100% satisfaction would be unrealistic.

Results over the last five years for the key reliability and energy efficiency service levels for which OJV sets service level targets are listed in Table 22 and customer satisfaction as indicated from past surveys are shown in Table 23. Several points should be noted in reviewing these figures:

- 2013/14 and prior years do not include the assets and expenses of the ESL network
- SAIDI and SAIFI for future years (starting with the 2015/16 disclosure year) are to be calculated using the new methodology in the 2015 Default Price-Quality Path Determination. Previously disclosed reliability results are shown below, however a recalculation of OJV's

SAIDI and SAIFI using the new Default Price-Quality Path method has also been completed, and is shown below as these are the relevant figures for OJV's trending and forecasting.

- Historical network spend includes atypical expenditure in 2013/14 associated with a Marlborough Lines Limited (MLL) initiative to carry out accelerated inspection programs on line condition and earth quality
- Historical non-network OPEX spend includes atypical expenditure in the 2013/14 and 2014/15 years associated with MLL's temporarily taking over as provider of engineering management services for OJV, with the excess driven predominantly by salaries for an increased resource base.

Table 22: Reliability and Energy Efficiency History

Measure		2010/11	2011/12	2012/13	2013/14	2014/15
SAIDI	Previous Disclosure Method	247.08	320.77	253.0	348.2	353.2
	New DPP method	186.9	217.7	184.8	249.1	269.7
SAIFI	Previous Disclosure Method	2.26	2.37	2.30	2.95	3.27
	New DPP method	1.99	2.30	2.08	2.68	2.93
Load Factor		78%	79%	79%	79%	79%
Loss Ratio		7.6%	6.9%	5.1%	5.5%	4.2%
Capacity Utilisation		30.4%	29.2%	29.7%	29.9%	28.1%
Network OPEX / ICP		219	239	236	286	229
Network OPEX / km		737	796	796	930	732
Network OPEX / MVA		20,099	21,640	21,535	25,880	19,018
Non-Network OPEX / ICP		118	156	186	234	313
Non-Network OPEX / km		398	517	628	760	999
Non-Network OPEX / MVA		10,845	14,061	16,973	21,157	25,964

Table 23: Customer Satisfaction History

Attribute	Measure	2011/12	2012/13	2013/14	2014/15
Planned Outages	Provided sufficient information. {CES: Q3a}	100%	93%	90%	100%
	Satisfaction regarding amount of notice. {CES: Q3c}	100%	93%	90%	96%
	Acceptance of maximum of one planned outage every year. {CES: Q1}	99%	97%	96%	100%
	Acceptance of planned outages lasting four hours on average. {CES: Q1}	88%	94%	90%	94%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q4b}	100%	88%	93%	89%
	Information supplied was satisfactory. {CES: Q8b}	71%	88%	82%	100%
	OtagoNet first choice to contact for faults. {CES: Q6}	2%	13%	26%	24%
Voltage Complaints	Number of customers who have made supply quality complaints {IK}	12	14	18	3
	Number of customers who have justified supply quality complaints {IK}	11	13	9	2

{ } indicates information source: CES = Customer Engagement Survey, IK = Internal KPIs

3.4.2. Benchmarking

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 26 to Figure 34, helps identify where OJV might look to improve from current service levels. Any year to year changes predicted are expected to be small and need to be backed up by planned projects or initiatives which would impact service levels. To aid in comparison, other predominantly rural lines companies of a similar network size (-50% to +100%) have been highlighted in gray boxes.

SAIFI - available EDB reliability results since 2013 show that the number of interruptions OJV's customers experience is comparable to the other predominantly rural lines companies. Customer surveys indicate that no significant increase in expenditure to change reliability is desired. However OJV will continue to exploit opportunities for improvement that offer the best reliability-increase-to-investment ratio.

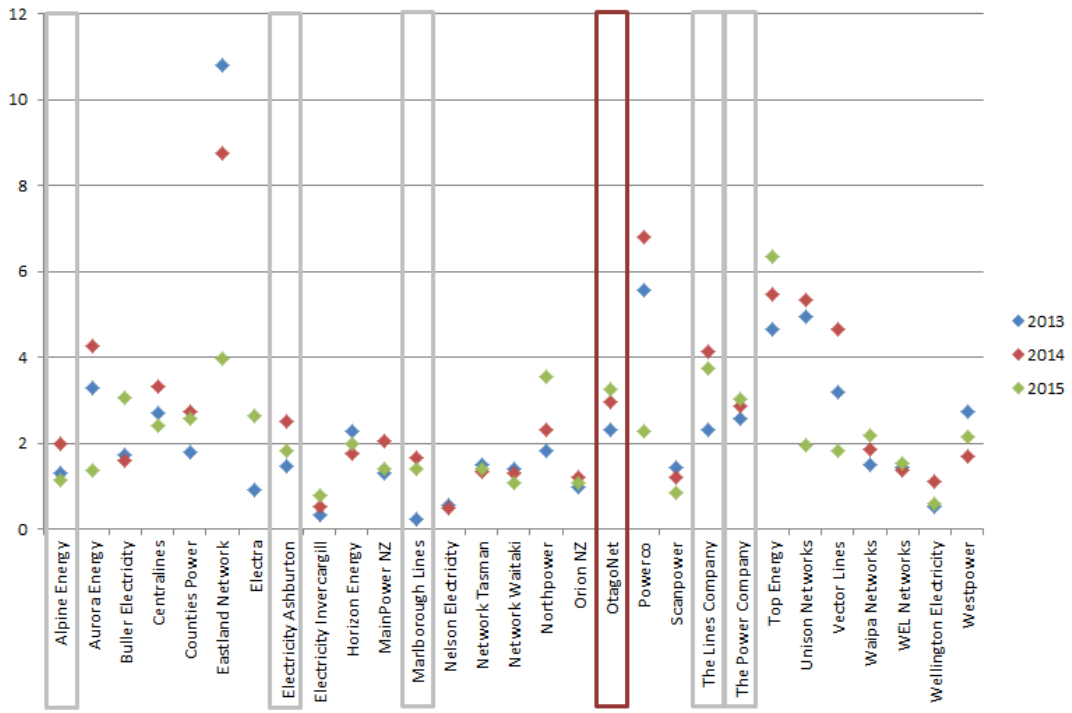

Figure 26: OJV SAIFI Comparison with Local EDBs

SAIDI – available EDB reliability results since 2013 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 in part by the sparsity of the network (increasing response times) and in part by the several severe weather events that occurred in each of 2014 and 2015. OJV will continue to exploit opportunities for improvement that offer the best reliability-increase-to-investment ratio.

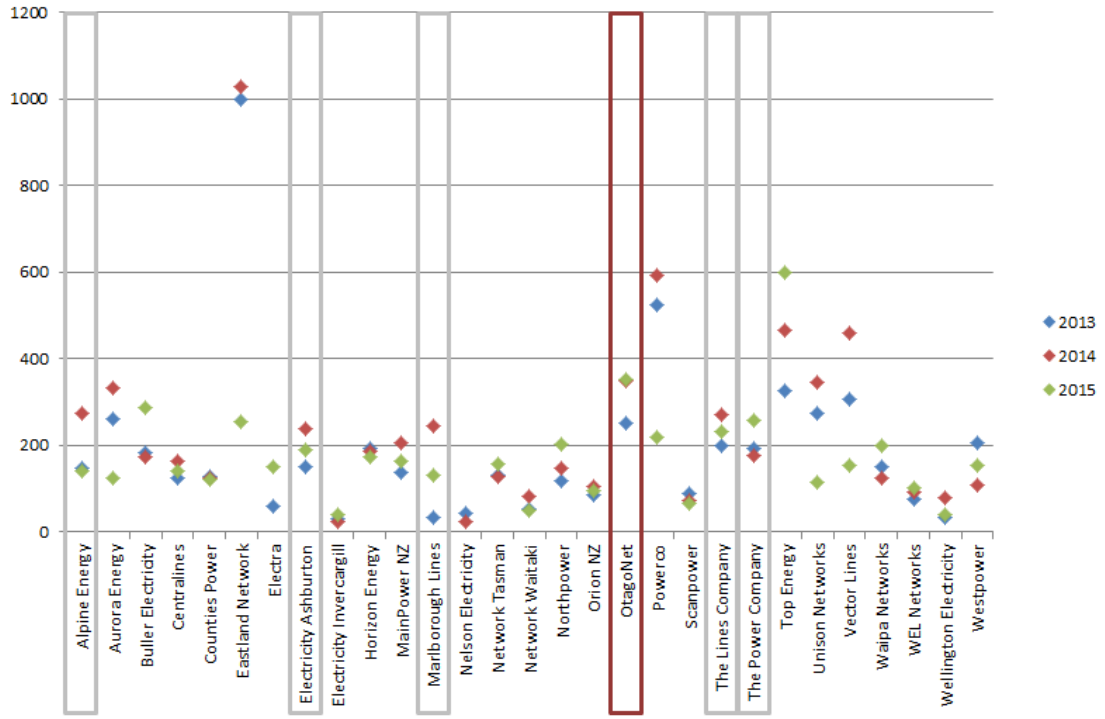

Figure 27: OJV SAIDI Comparison with Local EDBs

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 short term.

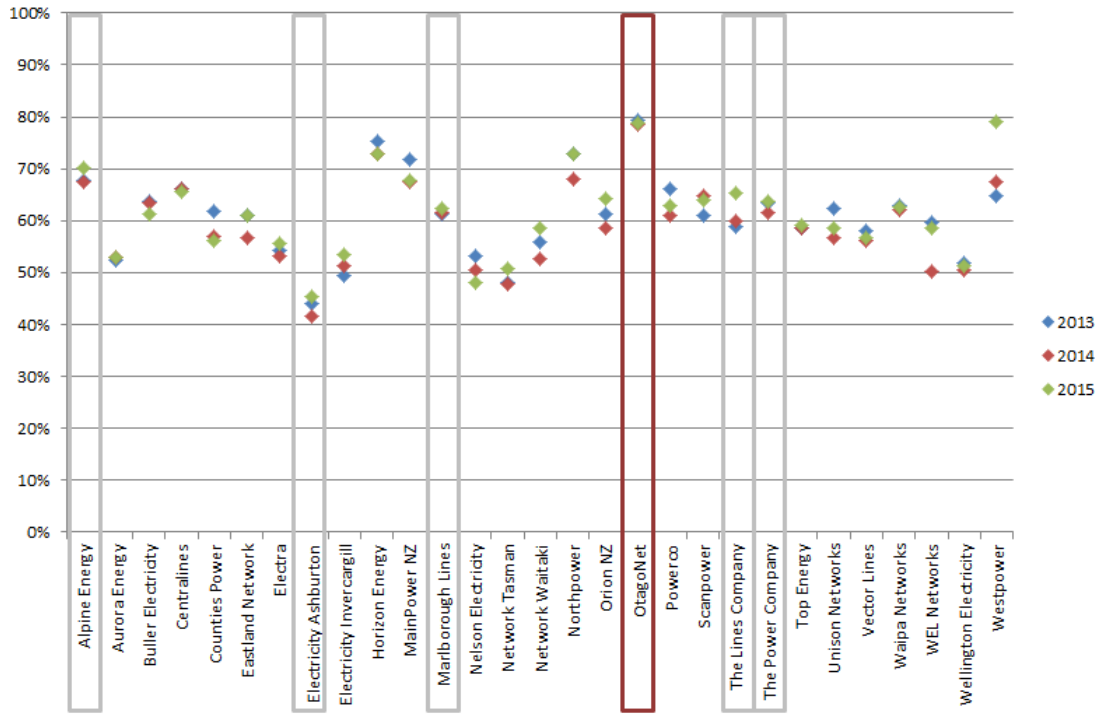

Figure 28: OJV Load Factor Comparison with Local EDBs

Loss Ratio - Despite energy efficiency getting increasing focus it is generally uneconomic to improve the efficiency of primary assets to improve losses. Also as losses are paid for by retailers, there is no financial incentive for the network company to reduce them apart from other technical issues such as poor voltage or current rating of equipment. Upgrading network equipment as growth occurs is expected to maintain losses at approximately present levels.

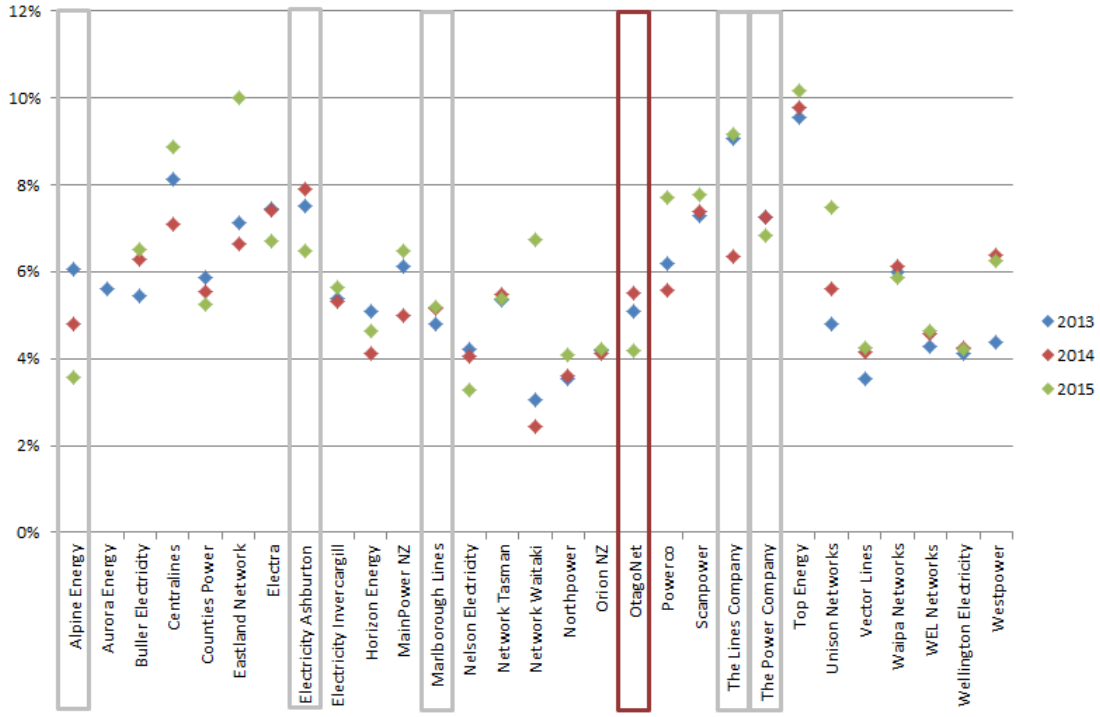

Figure 29: OJV Loss Ratio Comparison with Local EDBs

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 considerably due to retailer estimations and the target has therefore been set at the higher end of the range.

Capacity Utilisation - rationalisation[6] of transformers should improve capacity utilisation on the network but this will be offset somewhat by replacing overloaded transformers with appropriately sized units of standard ratings. Comparing OJV's capacity utilisation with other local EDBs highlights that OJV has an appropriate capacity utilisation factor for a predominantly rural network, therefore no strategies for improvement are warranted.

[6] Rationalisation is where one transformer is used to supply multiple customers, e.g. farm house could be supplied by a 50 kVA dairy shed transformer, but due to distance, usually requires its own 15kVA transformer. Peaks occur at differing periods so a smaller installed capacity usually results.

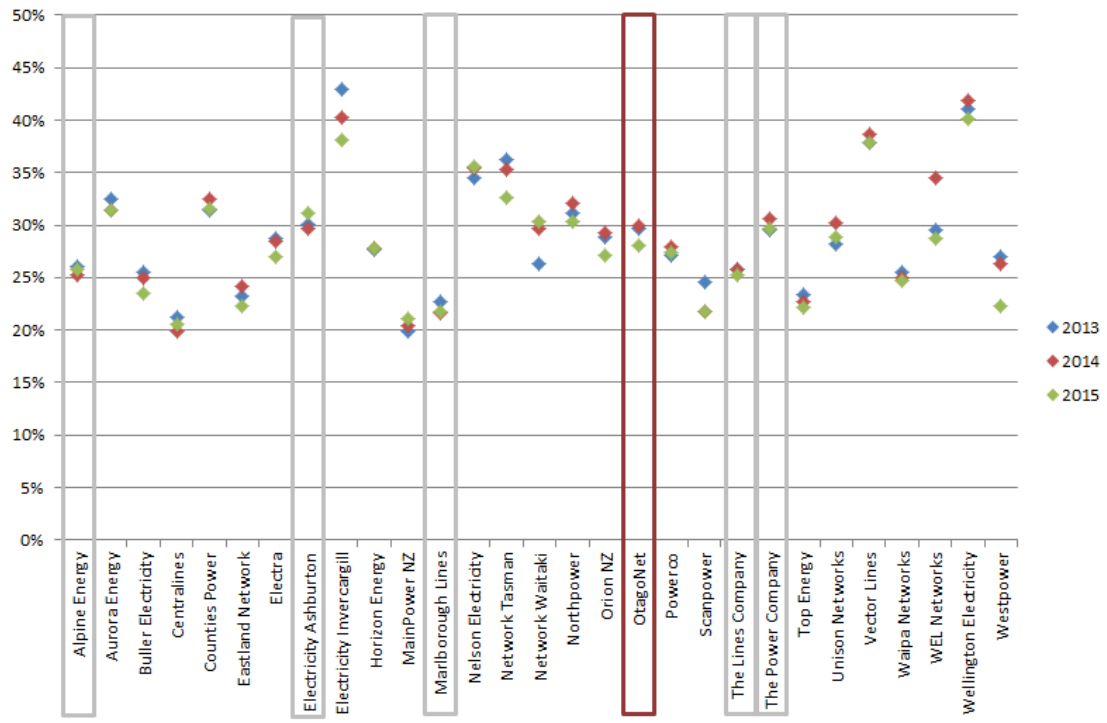

Figure 30: OJV Capacity Utilisation Comparison with Local EDBs

Financial service levels – OJV has redefined its financial service levels as discussed in section 3.2.1. However comparison with similar lines companies must be made cautiously; OJV has the lowest customer count, the lowest connection density, and the lowest level of connected distribution transformer capacity of any EDB in its peer group. This places upward pressure on the /ICP and /MVA metrics.

Examination of Figure 31 through Figure 36 shows that both Network OPEX and Non-Network OPEX are in line with or ahead of peers, once adjustment is made for distortion of the /ICP and /MVA metrics as described above.

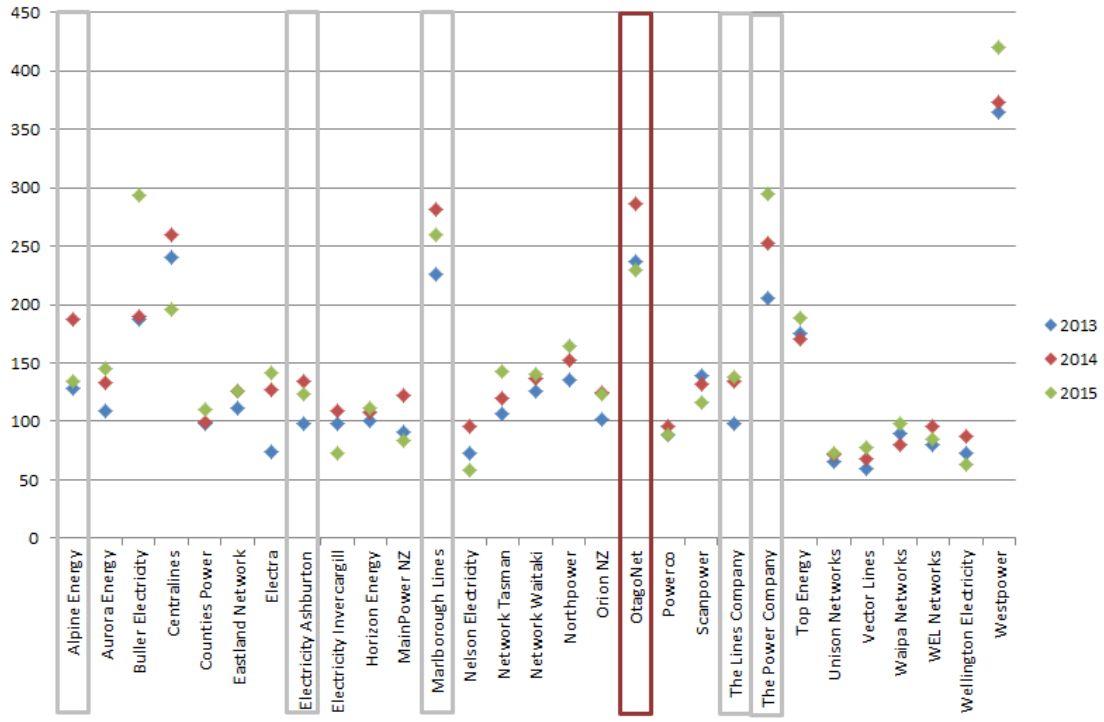

Figure 31: OJV Network OPEX/ICP Comparison with Local EDBs

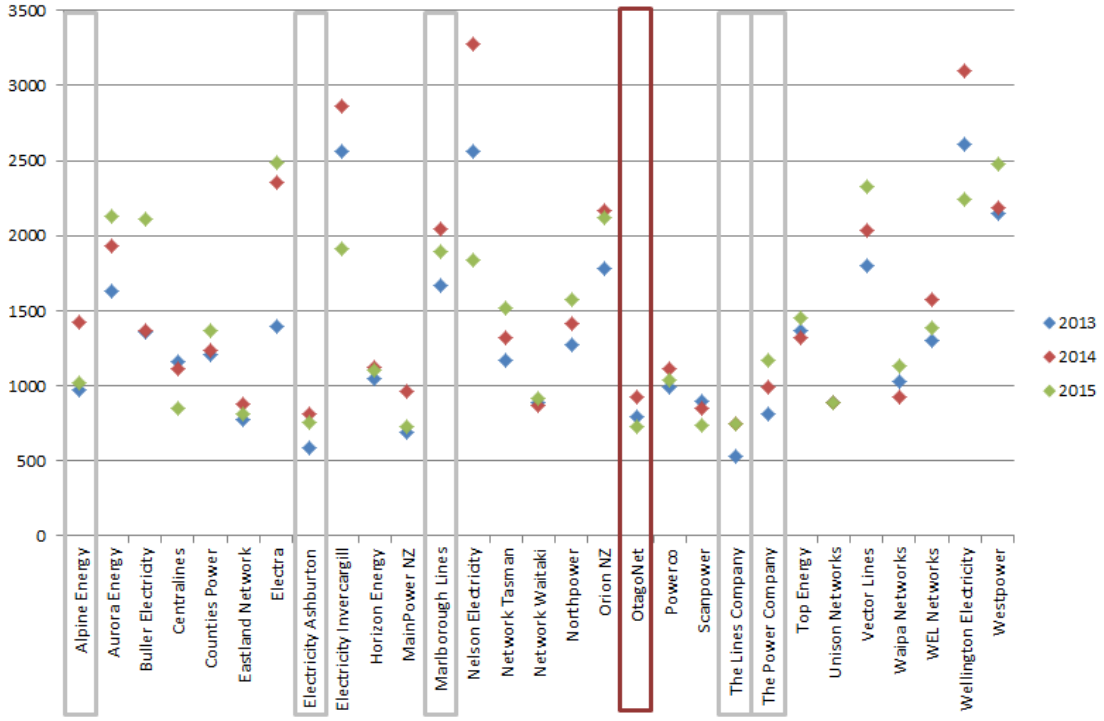

Figure 32: OJV Network OPEX/km Comparison with Local EDBs

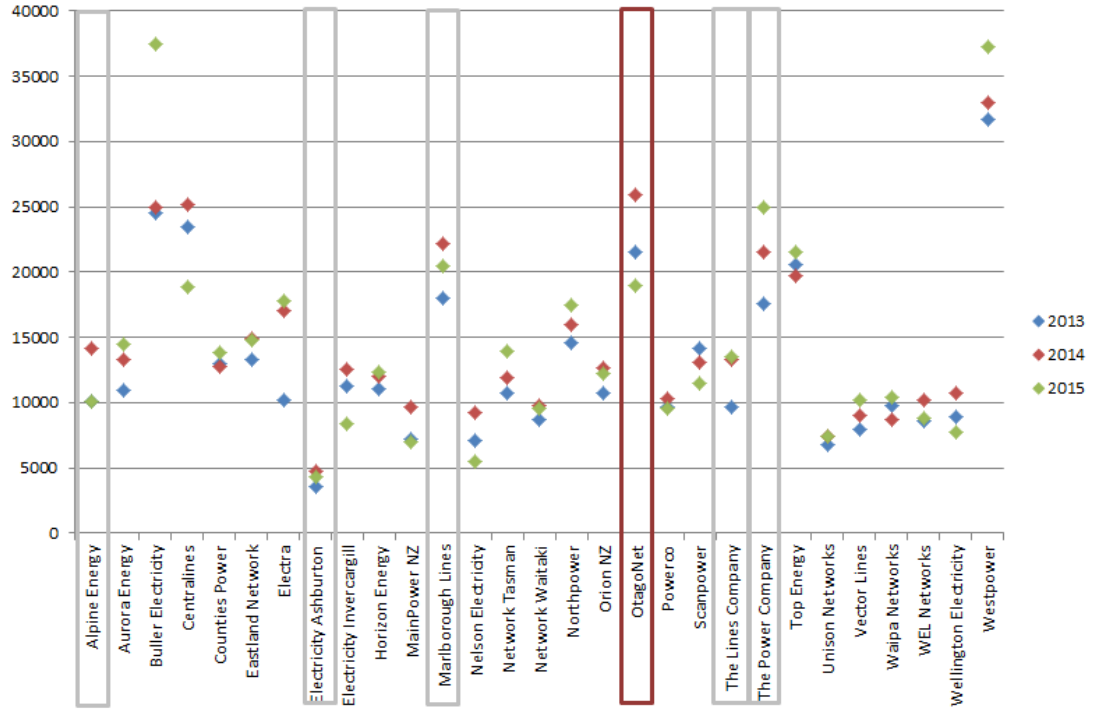

Figure 33: OJV Network OPEX/MVA Comparison with Local EDBs

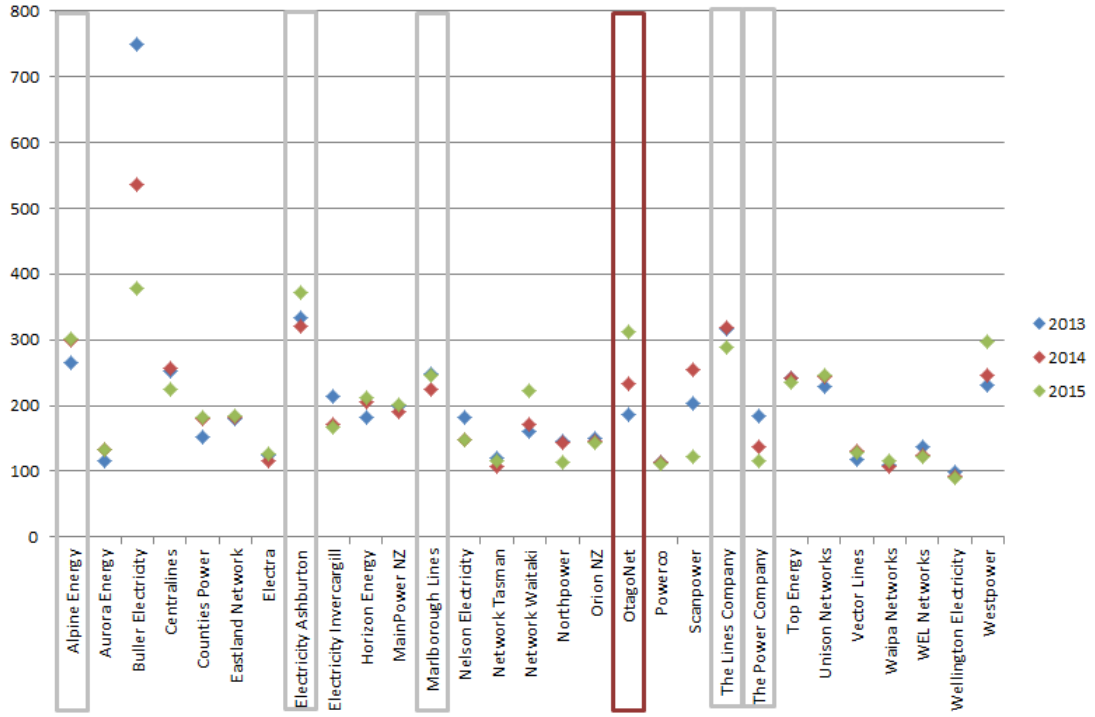

Figure 34: OJV Non-Network OPEX/ICP Comparison with Local EDBs

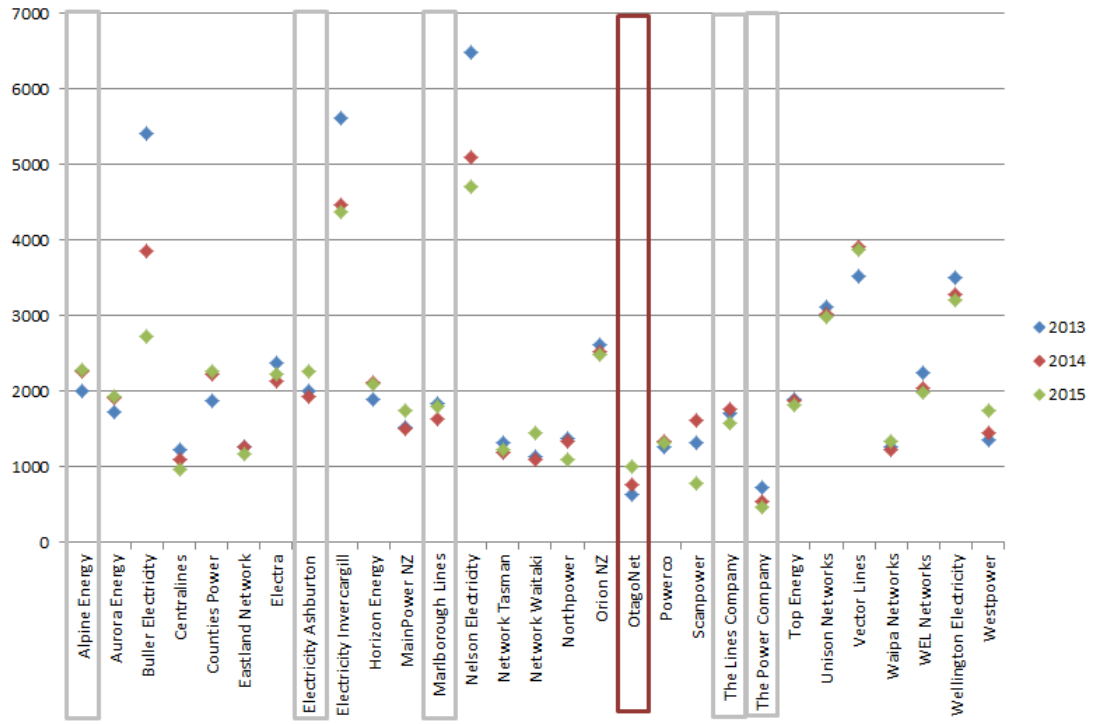

Figure 35: OJV Non-Network OPEX/km Comparison with Local EDBs

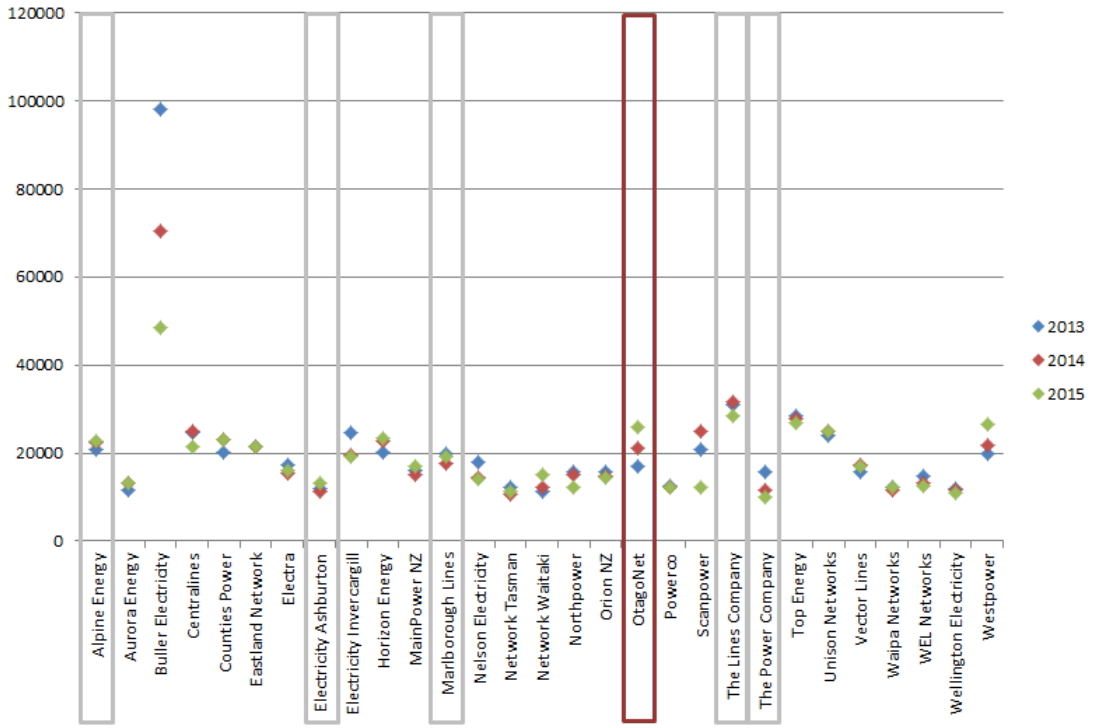

Figure 36: OJV Non-Network OPEX/MVA Comparison with Local EDBs

4. Development Planning

OJV monitors the existing network assets and ensures their operation 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.

4.1. Development Criteria

Network development is primarily associated with creating additional network capacity for supplying increasing demand (customer load). Large generation or an aggregation of many small generators may also become the dominant driver for increased capacity on some areas of the network. Requirements for maintaining or improving service levels, whether driven by statute, customer and other stakeholders' desire or internal strategic initiatives, also create development drivers. 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.

Network developments are triggered by events that necessitate changes to network capacity or service levels. These trigger events may directly dictate a development requirement; for example a connection request from an intending customer requiring an increase in network capacity to match their additional load requirements. The trigger may also be less direct, for example when load growth exceeds a threshold for increased security; the security trigger threshold being predetermined based on a strategic "line in the sand" designed to provide particular service levels when applied consistently across the network. Identified development triggers and the thresholds at which they are set form the key criteria for OJV's network development planning.

4.1.1. Growth Based Development Triggers

At its most fundamental level, demand is created by individual customers drawing (or injecting) 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 up the network, load diversity tends to favour better load factor and capacity utilisation.

Demand growth creates the predominant driver for network development; therefore growth triggers have been identified, and where appropriate, corresponding thresholds have been set to achieve desired service levels. These development triggers provide simple scenario based indicators for development requirements, although reliability incorporates probabilistic considerations. The first step in meeting future demand (whilst maintaining service levels) is to determine if the projected demand will exceed any of OJV's defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 24.

If a trigger point is exceeded OJV will then identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points. These options are described later in this chapter (refer section 4.1.4) which also embodies an overall preference for avoiding new

capital expenditure. Endeavours will be made to meet demand by other, less investment-intensive means, as new capacity has balance sheet, depreciation and ROI implications for OJV. This point links strongly to the discussion of asset life cycle in section 5.

Table 24: Development Triggers and Typical Network Solutions

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 be need 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 protection operation, temperature alarms or voltage complaints.	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.
Security and Reliability	Load reaches the threshold for increased security as defined in OJV's security standard set out under section 4.1.6. 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.

4.1.2. 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 reliability 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 projects may be triggered by a complex interaction of many factors or driven (or required) by external influences. Justification for these projects will be discussed later in this chapter (refer section 4.4). Examples are the shifting perceptions around staff/personnel safety or acceptable levels of risk; these create drivers for network development projects that do not derive from demand growth.

4.1.3. Relationship with Lifecycle Maintenance

It is important to understand the relationship between network development, lifecycle management practices and the network service levels discussed in section 3. Demand growth on fixed network assets erodes supply reliability over time as a greater number of customers or level of demand is affected when a supply interruption occurs. Using increased network maintenance to preserve network reliability against demand growth requires a shift away from the most economic asset age profiles (generally about 50% average life) which then must be sustained, so that approach is uneconomic as well as inherently limited. From an holistic point of view lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration while network development counteracts declining reliability in the face of demand growth.

4.1.4. 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 as well as an appropriate level of standardisation and these strategies will be discussed later in this section. However before capital intensive upgrades are required the following actions, in a broad order of preference, are considered as solutions 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 poor 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, for example 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 require changes to 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 blunted by the retailer's practice of repackaging fixed and variable charges.

- Install distributed generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. Generation might be particularly attractive 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 200kVA distribution transformer with a 300kVA 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.

4.1.5. 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 and simplified selection of equipment and materials. Also standardised designs or design criteria avoids "reinventing the wheel", can incorporate more lessons learnt than could otherwise be practically managed, and simplifies the design process. 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 can be more efficiently achieved when shared across the combined network's asset base, or lessons learnt on one network can be incorporated into standards which then benefit the other networks to which they are applied. Standardised design is used for line construction with a Construction Manual and standard drawings in use by Contractors.

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 achieved 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 25:

Table 25: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300mm^{2}Al @ 11kV 35 & 150mm^2 Al @ 22 kV	Stocking of common sizes, lower cost
	Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Chlorine, Helium, Iodine, Neon	Low corrosion, low resistance, cost, stocking of common sizes
	Aluminium conductor steel reinforced (ACSR) – Magpie, Squirrel, Flounder, Snipe	Higher strength (longer spans, snow load)
	Low Voltage Aerial Bundled Cable (ABC): 35, 50 & 95mm^{2}Al (two or 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 400A, field circuit breaker 400A), 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.
33kV & 11kV 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 (size based on after-diversity maximum demand), 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.

4.1.6. Security Standard

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:

Provision of alternative supplies: 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; but meshing is often impractical in the rural Otago network where the ruggedness of the landscape limits opportunities for feeder interconnection, and voltage drop due to the sparsity of customers weakens those potential interconnection points that do exist. Where a strong interconnection point does exist, the number of switches on the feeder also contributes to security, as it governs the size of the section between switches which must be isolated after a fault for the duration of the repair.

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, therefore this approach is only used when justified by the size of the connected load.

Use of generation: May 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, though 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.

Use of demand management: (Interruptible load) Demand management can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

Where a substation exists for the sole benefit of a single consumer, their preference for security will be documented in their individual line services agreement and will set the minimum security level. The preferred means of providing security to rural substations will be backfeeding at distribution voltage where possible, but the low connection density of the network limits such opportunities. The preferred means of providing security to urban zone substations is via secondary subtransmission assets, with any available back-feed at distribution voltage providing an extra level of security.

Table 26 summarises the security standards adopted by OJV.

Table 26: Target security levels

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

4.1.7. Determining Capacity

Where 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 of minimising the long term cost of service of sufficient quality ahead of demand.

Sizing network equipment carries a cost efficiency 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 where asset lifetimes span periods of high and/or unpredictable growth. Installing assets with too much spare capacity means over-investment; but if assets are undersized, the asset will need to be replaced early at sometimes significant expense. In many cases standardisation will limit the options available to assist in the selection of capacity.

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 future 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 27. Clearly understanding load growth into the future is crucial to making sound investment decisions. The method and considerations for forecasting network demand are discussed later in this section.

Table 27: Capacity Selection Criteria

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

4.1.8. Energy Efficiency

OJV strives to make decisions based on the best outcome for its customers and as customers pay for losses on the network in their energy bills, cost benefits are considered in delivering energy as efficiently as possible. However selection of more efficient assets rarely is justified as a cost benefit to customers. In the few cases where there is an economic justification to reduce losses in this way OJV will use these solutions, for example specifying low loss cores used in the magnetic circuits of transformers. Otherwise power consumed by OJV and its organisational partners is used responsibly with heating of substation buildings and PowerNet's office buildings heated using efficient heat pump technology, insulation and draft control etc. where appropriate.

One of the longer-term projects underway on the OJV network is the reconfiguration of the Palmerston area subtransmission network. Power was formerly routed from Dunedin 50 km up the coast to Palmerston on the Transpower network, and then sent back down the coast on the OJV network to the settlements of Waikouaiti and Waitati.

The purchase of the Transpower Palmerston assets was carried out with the intention of supplying the coastal townships with power directly from Dunedin, thus reducing subtransmission losses in the area by 488,000 kWh per year, or 46%.

4.1.9. Identifying the Best Option

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 28 summarises the decision tools used to evaluate options depending on their cost.

Table 28: Decision Tools Used Based on Cost

Cost and 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
Up 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.	Chief Engineer
Up to $1,000,000, individual projects likely to be strategically significant. Timing may be altered to allow resource focus on higher priority projects.	Extensive spreadsheet model to calculate NPV that might consider several variation scenarios. Risk analysis including environmental and safety considerations and consideration of risk management costs. 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 manged through planning meetings and spreadsheet models. Ongoing stakeholder consultation may be required especially large customers. Business case presented to the Governing Committee highlighting options considered and justification of recommended option.	Governing Committee Approval

4.1.10. Prioritising Development Projects

Development projects are prioritised in line with the principles set out in section 1.4.2 when competition for resources exists. Safety, viability, pricing, supply quality and compliance is the order of priority for manging these conflicts. These factors cannot be applied absolutely, 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 Governing Committee for approval with supporting justification in the updated AMP.

4.2. Forecasting Demand and Constraints

It is necessary to be aware several years in advance of when trigger points might be exceeded; development projects can take many months or even years to complete, and significant prior notice is necessary to ensure capacity can be made available by the time it is needed. This is achieved through demand forecasting based on trends taken from historical data, as well factoring in the many demand drivers which may cause future deviation from status quo trends.

4.2.1. OJV's Current Demand

OJV's maximum demand (MD) of 61.8 MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 10:30 on the 26th of May 2014. The ESL MD of 2.65 MW occurred at 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 41.2 MW, with 0.8 MW of that load contributed by ESL. The individual maximum demands are shown in Table 29.

Table 29: GXP and Generation Demands

Grid Exit Point	Maximum Demand 2014/15	Coincident Demand 2014/15
Balclutha GXP	27.6 MW (08:30 03/04/14)	24.9 MW (10:30 26/05/2014)
Frankton GXP	2.6 MW (09:30 15/07/14)	0.8 MW (10:30 26/05/2014)
Naseby GXP	28.6 MW (21:00 26/03/15)	0.7 MW (10:30 26/05/2014)
Halfway Bush GXP	5.7 MW (18:30 14/08/14)	5.4 MW (10:30 26/05/2014)
Paerau Generation	12.4 MW (09:30 19/08/14)	6.6 MW (10:30 26/05/2014)
Falls Dam Generation	1.3 MW (02:30 14/07/14)	1.3 MW (10:30 26/05/2014)
Mt Stuart Generation	7.5 MW (19:00 30/05/14)	1.5 MW (10:30 26/05/2014)

4.2.2. Demand History and Trend

System Level

Growth trends are difficult to establish as there is significant random variation on top of underlying growth. Generally a ten year rolling average will vary substantially between successive years. Trending over a longer term tends to "average" out the random variations but also obscures recent changes to underlying growth. Some causes may be identified with hindsight but are typically difficult to predict, for example a drought initiating increasing irrigation load. Growth is plotted and trend lines over various time periods are considered along with known events affecting consumption patterns before arriving at a reasonable estimate of growth which can be used for forecasting future demand and consumption.

Figure 37 shows the overall OJV data since 1950 and highlights the substantial increase in load associated with the Macraes Flat gold mine. A slight dip in maximum demand circa 1996 is visible where computerised load control was introduced.

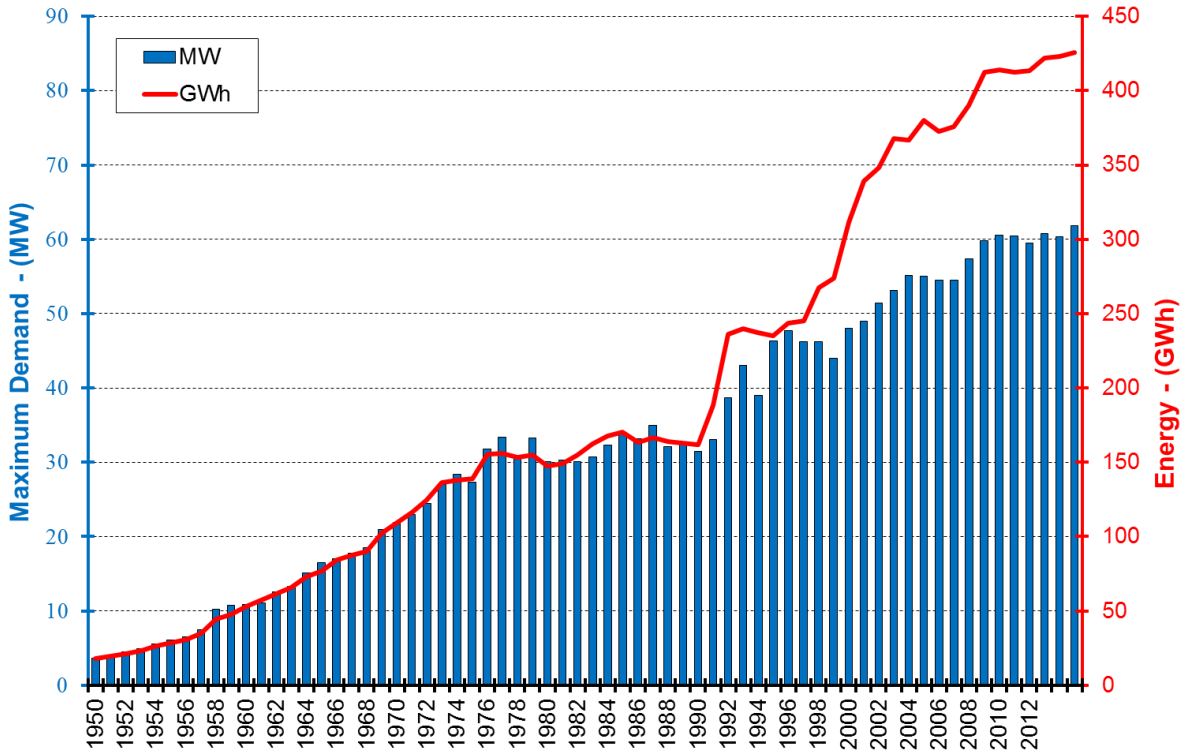

Figure 37: Maximum Demand and Energy Transmitted

Analysis of historic demand and energy usage over the last 10 years or so gives maximum demand growth and energy consumption growth of about 1.2% each. The overall effect of the drivers of future demand mentioned in section 4.2.3 is not expected to significantly alter these growth trends in future years.

While the growth rate at system level has been reasonably consistent since 2009, it must be acknowledged that actual demand growth at localised levels (which will influence costs) can vary anywhere from negative to highly positive. No substantial reductions are foreseen due to the

removal of the requirement to supply in 2013, as the few sections of the network that could be considered uneconomic to replace do not contribute significant load. The most significant drivers of the network demand over the next 10 to 15 years are examined in detail in the following sections.

Substation Level

Each zone substation recorded the maximum demands as listed in Table 30. This maximum demand is exclusive of any short term load transfers so as to be more indicative of actual area maximum demand.

Table 30: Substation Demand

Zone Substation	Max Demand (MVA)							Notes
	2013/14	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08	
Charlotte Street (Balclutha)	6.5	6.1	6.9	6.2	7	7	6.5	
Clarks	0.4	0.4	0.3	0.3	0.3	0.4	0.4	
Clinton	2.1	2	2	2	2	2.1	2	
Clydevale	2.9	2.7	2.3	2.1	2.1	2	1.9	
Deepdell	0.1	0.1	0.1	0.1	0.2	0.2	0.2	
Elderlee Street (Milton)	4.6	6.4	5.7	6.3	6.2	6	5.9	Load transferred to Milburn 2013
Finegand	1.1	1.1	1.1	1.7	1.6	1.8	1.4	
Glenore	0.8	0.7	0.6	0.7	0.8	1	0.9	
Golden Point	3.4	4.2	3.6	3.3	2.9	2.5	1.7	Load transferred to Macraes 2015
Hindon	0.3	0.2	0.3	0.3	0.3	0.3	0.3	
Hyde	1.2	1.2	1.3	1.4	1.3	1.3	1.3	
Kaitangata	1.4	1.4	1.4	1.5	1.4	1.5	1.4	
Lawrence	1.2	1.5	1.4	1.4	1.5	1.6	1.6	
Linnburn	1							
Merton	2.5	2.4	2.5	2.6	2.6	2.6	2.7	
Middlemarch	0.8	0.7	0.7	0.6	0.7	0.8	0.8	
Milburn	2	2.4						
North Balclutha	2.9	2.8	3.1	3	2.9	3.1	3.5	
Oturehua	0.2	0.2	0.2	0.2	0.2	0.1	0.2	
Owaka	1.7	1.5	1.7	1.7	1.6	1.6	1.7	
Paerau	0.3	0.3	0.2	0.2	0.2	0.4	0.3	
Paerau Hydro	12.8	12.8	12.3	12.6	12.1	11.9	12.1	
Palmerston	2.2	2.2	2.4	2.2	2.2	2.2	2.3	
Patearoa	1.7	1.7	1.7	1.6	1.6	1.9	1.7	Load transferred to Linnburn 2014
Port Molyneux	0.6	0.7	0.7	0.6	0.6	0.9	0.7	
Pukeawa	0.4	0.4	0.4	0.2	0.2	0.2	0.2	

Zone Substation	Max Demand (MVA)							Notes
	2013/14	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08	
Ranfurly 33/11	2.1	2.2	2.1	2.2	2.4	2.2	2.1	
Ranfurly 33/66	30.9	25.3	23.5	24.3	23.7	27.8	28.1	
Remarkables	2.4	2.2	2.2	1.5	1.5	1.1	0.9	
Stirling	4	3.9	4.3	4	3.8	4.1	3.1	
Waihola	1.1	1.2	1.1	1	1.1	1	1.2	
Waipiata	1.4	1.3	1	1.1	1.1	1	1	
Waitati	1.7	1.5	1.8	1.6	1.6	1.4	1.7	
Wedderburn	0.2	0.2	0.2	0.2	0.2	0.2	0.3	

A temporary substation has been established at Linnburn, to accommodate the extremely rapid irrigation-based load growth in the Patearoa area until the Puketoi Area Upgrade can be completed (see section 4.4).

4.2.3. Drivers of Future Demand

Future demand is forecast by understanding historical trends, projecting these trends into the future and altering these projections by factors which cause deviation of demand away from the current trends.

Table 31: Drivers of Future Demand

Demographics & Lifecycle	
Irrigation & Dairy	**Effect:** Accelerated growth particularly in the Maniototo and Clydevale regions
Description: Irrigation is common in the drier inland areas of Otago such as the Maniototo valley and Clydevale. The Otago District Council has recently placed more stringent restrictions on the use of water which encourage the use of spray irrigators; which are both more water-efficient and more electrically demanding than the pre-existing irrigation schemes. The Ministry of Primary Industries has also placed more stringent requirements on the chilling of milk on dairy farms, which is expected to increase load in areas with a substantial dairy population such as the Clydevale region.	
Population Growth and Decline	**Effect:** Accelerated growth in the Frankton area. Population in other areas largely static.
Description: Recent census data shows no major changes in population in the rural Otago areas serviced by OJV. However Frankton increased in size by 12.5% between 2001 and 2013 with the rate of recent network developments indicating a continuation of this trend.	
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.	

Convenience of Electrical Heating	**Effect:** New buildings almost invariably use heat pumps for space heating
Description: Heating associated with low temperatures during winter (-5°C frosts are not uncommon in the area). Increased electrical heating due to heat pump conversion is thought to be mostly offset by more efficient electrical heating replacing stand-alone electric heaters.	
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.	

Figure 38 shows population projections for OJV's network area as estimated by Statistics New Zealand from 2013 Census data. Also the total population of the group 65 years and older is shown, highlighting the predicted significant aging of the population.

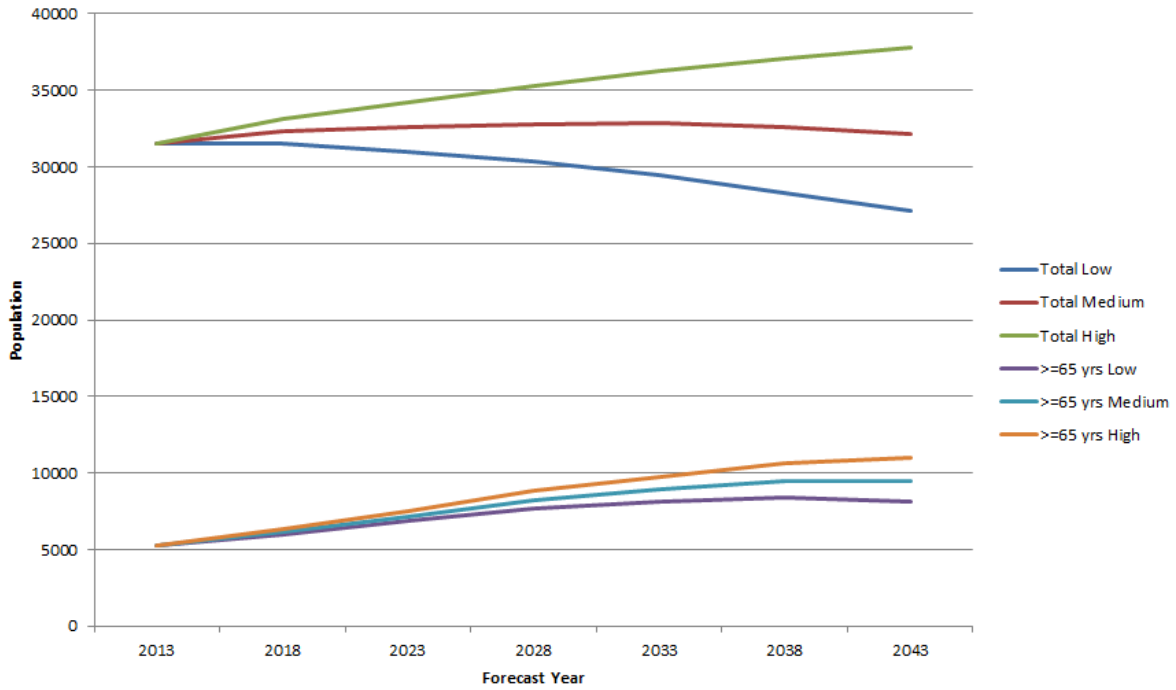

Figure 38: OJV Population Projections

Table 32: Additional Drivers of Future Demand

Environment and Climate	
Removal of Coal as Heating	**Effect:** Continuation of existing trends
Description: Solid Energy had previously advised it would withdraw from supplying coal to the household market by the beginning of 2013 in line with the National Environmental Standards for air quality but has since been revised to 2016. This would likely 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 particularly in urban areas 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 to 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 Ambient Temperature	**Effect:** Small increase in maximum demand on inland rural substations

Description: Increasing ambient temperature predicted by climate scientists may create increased demand for cooling and irrigation systems. This increased consumption would occur in the warmer months and therefore coincide with the peak demand in inland rural substations. In areas where the winter heating load dominates, increased cooling loads in summer months may improve load factor by a small degree.

Economy

Major Industry Continuance or Growth	**Effect:** Marked substantial load change at isolated sites

Description: OJV supplies power to several industrial customers whose load levels have a significant effect on the network at the subtransmission level. The largest of these 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. However there has been no confirmation to OtagoNet of any future large changes by this customer.

A small upgrade at the dairy plant at Clydevale is underway at present. However there have been indications that a much more substantial upgrade (roughly a doubling in size) could occur in the medium term. The existing subtransmission network would be incapable of carrying this extra demand reliably and therefore some upgrade work would be required to supply it at 33 kV.

Similarly a small forestry-related upgrade is underway in the Milburn area with the potential for a much more substantial upgrade in the future. An upgrade of sufficient size would exceed the firm capacity of the local substations and require upgrade work to be carried out.

As there is no confirmation of any of these load changes taking place, they have not been included in forecasted growth; however contingency plans have been made in case they do eventuate.

$NZD variation	**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.

Technology	
Electric Vehicles	**Effect:** Negligible over planning period
Description: Electric vehicles have the potential to have a large impact on network demand with sufficient penetration into the transport sector. Electric vehicles are becoming more attractive in the North Island, particularly for rural customers making regular commutes into town (within the range of an electric vehicle). It is expected that the majority of this load should be able to be managed so that it is consumed at off-peak times (especially overnight) and therefore would have much less impact on peak demand and even improve load factor. Some demand increase is expected in the long term but is likely to be beyond the ten year planning horizon and so has not been included in growth forecasts.	
Distributed Generation	**Effect:** Generation tends not to coincide with network peak demand therefore the effect on network peak demand is expected to be negligible.
Description: The vast majority of the distributed generation (as opposed to embedded generation such as Falls Dam, Paerau, and Mount Stuart) has so far been solar installations and this trend is expected to continue for the foreseeable future. Relatively low numbers of new solar connections have been seen on OJV's network to date although the trend is expected to increase as economics improve for solar installations. However the overall generation connection density is very low and not expected to increase enough over the ten year planning horizon to affect peak demand. Without energy storage solar generation is only able to offset load during available sunshine hours which don't typically coincide with peak demand; especially with shorter days over the colder winter months when the greatest demand occurs on the network. Additionally variation in the weather means solar generation cannot be relied on at any time including peak load periods. Total energy consumption is likely to be reduced to some extend by solar installations within the planning period however energy does not tend effect planning which focusses on providing capacity for peak demand periods.	
Energy Storage	**Effect:** Not expected to be economic for customers within the ten year planning horizon and therefore negligible effect on network demand.
Description: Energy storage is one technology that could have a large impact on network demand especially if used in combination with distributed generation installations. Storage could make it feasible for customers to go "off-grid" with a sufficiently sized solar system or other generation source. However this technology is not expected to be economic for some time and so is not considered likely to impact on peak network demand in the next ten years. It may however be a feasible alternative for customers at the end of long lengths of dedicated line that are no longer economic to maintain.	
Energy Efficiency	**Effect:** Negative growth driver accounted for in a part of the driver Energy Conservation Initiatives discussed above.
Description: Improving energy efficiency has been a government strategy for several years as discussed above under 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.	
Internet of Things	**Effect:** It is not considered likely that this technology will be extensively used in the near future and has 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 plans would be able to react sufficiently quickly.
Description: The internet of things refers to the interconnection of the internet and many electronically enabled devices. In particular "smart appliances" may enable centrally controlled management of a dwelling's 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.	

4.2.4. Demand Forecasts

Table 33 shows the aggregated effect of substation demand growth for a 10 year horizon at the GXPs supplying OJV.

Table 33: GXP Demand Growth

GXP	Rate and nature of growth	Provision for growth to 2025
Balclutha	0.75% limited irrigation/dairy related growth	Recent commissioning of capacitors and indoor switchboard removed previous transformer branch constraint
Frankton	3.5% driven largely by residential expansion both inside and outside OJV network	Forecast load growth will exceed the 110 kV circuits' supply capacity from approximately 2026. Options to be investigated closer to the time.
Naseby	1.5% reflecting increasing irrigation-related load in the Maniototo and Middlemarch	Forecast remains within firm capacity
Halfway Bush	1.0% driven largely by Dunedin (outside OJV network)	Load will be transferred off the 110 kV bus to the 33 kV bus with the cessation of the current interim arrangement. Upgrade work and load shifting arrangements will be carried out at Halfway Bush to accommodate this 33 kV load, this is scheduled for completion in 2018. Transformer replacement programme will continue at Halfway Bush to keep 33 kV firm capacity ahead of regional load.

Table 34 identifies the rate of growth projected to zone substation level over a 10 year horizon, along with the provision expected to be made for future growth.

Table 34: Substations Growth Projection

Substation	2015 Design Capacity (MVA)	YE 2015 MD (MVA)	Annual Growth	Projected 2025 MD (MVA)	Notes
Charlotte Street (Balclutha)	10.0	5.5	0.0%	5.5	Above firm capacity Load transfer available
Clarks	0.5	0.4	1.0%	0.4	
Clinton	2.5	1.6	1.0%	2.0	
Clydevale	2.5	3.5	5.0%	5.1	Transformer temporarily uprated using fans Upgrade to 5 MVA transformer near completion Irrigation
Deepdell	0.8	0.1	0.0%	0.1	
Elderlee Street (Milton)	10.0	4.7	0.0%	4.7	
Finegand	2.5	1.1	0.0%	1.1	
Glenore	1.5	0.6	0.0%	0.6	

Substation	2015 Design Capacity (MVA)	YE 2015 MD (MVA)	Annual Growth	Projected 2025 MD (MVA)	Notes
Golden Point	5.0	0	0.0%	0	Now backup substation only
Hindon	0.5	0.2	0.0%	0.2	
Hyde	2.5	1.2	0.0%	1.2	
Kaitangata	2.5	1.3	0.0%	1.3	
Lawrence	2.5	1.2	0.0%	1.2	
Linnburn	1.0	1.0	5.0%	N/A	Temporary substation
Merton	5.0	2.9	0.0%	2.9	Above firm capacity Transformer replacement planned
Middlemarch	2.5	0.7	1.0%	0.8	Some irrigation
Milburn	3.0	1.5	0.0%	3.0	Step change due to industrial expansion Only minor works required to expand to two-transformer site
North Balclutha	5.0	3.0	0.0%	3.0	
Oturehua	0.8	0.2	0.0%	0.2	
Owaka	2.5	1.7	0.0%	1.7	
Paerau	0.8	0.3	0.0%	0.3	
Paerau Hydro	30.0	12.2	0.0%	12.2	
Palmerston	5.0	2.3	1.0%	2.5	
Patearoa	2.5	1.5	5.0%	5.0	Step change with removal of Linnburn temporary sub 2018 adding load to Patearoa Transformer upgrade commencing
Port Molyneux	2.5	0.7	0.0%	0.7	
Pukeawa	0.8	0.5	4.0%	0.7	Irrigation
Ranfurly 33/11	5.0	2.2	1.0%	2.3	Irrigation
Ranfurly 33/66	50.0	26.3	0.0%	26.3	Above firm capacity, single customer, constraint acknowledged
Remarkables	25.0	3.2	10.0%	6.4	Rapid urban expansion
Stirling	5.0	4.2	0.0%	4.2	
Waihola	1.5	1.1	0.0%	1.1	
Waipiata	2.5	1.4	5.0%	2.1	Irrigation
Waitati	2.5	1.5	0.0%	1.5	
Wedderburn	0.8	0.2	0.0%	0.2	

It should be noted however that experience strongly indicates it would be rare to ever get more than a few months confirmation, sufficient to justify significant investment, of definite changes in an existing or a new major customer's demand. This is because most of these customers operate in fast-moving customer markets and often make capital investment decisions quickly themselves and they generally keep such decisions confidential until the latest possible moment. Perhaps the best

that OJV can do is to identify in advance where OJV's network has sufficient surplus capacity to supply a new large load but, as experience shows, industrial siting decisions rarely, if ever, consider the location of energy supply – they tend to be driven more by land-use restrictions, raw material supply and transport infrastructure.

Table 34 assumes no unforeseen changes in growth rates, as estimated from demand graph trends and local knowledge, or step changes due to connection or loss of large customers. Heavily loaded sites will be monitored more closely if data indicates capacity will be exceeded in the short term. Annual preparation of this data will highlight sites that vary from the above model and the planned works adapted for each situation, with some upgrades delayed or brought forward.

4.3. Issues Arising from Estimated Demand

OJV's network includes the constraints as shown in Table 35:

Table 35: OJV Network Constraints and Intended Remedy

Constraint	Description	Intended remedy
Capacity at GXPs	Limited N-1 supply capacity available from the Halfway Bush 33 kV bus	Interim arrangement with OJV drawing power from Halfway Bush at both 110 kV and 33 kV. Future 33 kV bus upgrade and load shifts will allow a full 33 kV connection.
	Tower failure on the dual circuit supplying the Frankton GXP could interrupt power to the entire GXP	No remedy advised by Transpower. Very low probability event.
Capacity at Zone Substations	Sharply accelerated irrigation related growth in the Patearoa/Puketoi area has caused the load to exceed the capacity of the Patearoa substation. Some load has been transferred to the temporary Linnburn substation.	The Patearoa substation will be upgraded within the lifetime of the Linnburn substation. When similar drivers accelerate the load growth in the Gimmerburn area, the Patearoa substation will be expanded to accommodate the extra load and designed to a level of supply security appropriate to its new capacity.
Subtransmission Reliability	The relatively large Merton and Waitati substations are only supplied by a single subtransmission line	Conversion of one Halfway Bush line to 33 kV has allowed Waitati to be backfed in the event of a subtransmission fault. Continuing upgrades will allow Merton to be backfed, and ultimately N-1 security to both substations.
Subtransmission Capacity	A short section of line on one of the dual circuits connecting Balclutha GXP to Charlotte St is undersized for the current maximum demand in the backup situation.	A workaround currently exists: load can be rerouted through the subtransmission network if backup is required at times of maximum demand. The section of line will be replaced with a higher capacity conductor.
Distribution Voltage Drop	The voltage drop at the end of some distribution lines fall below OJV triggers.	The feeder supplying Chrystalls Beach will be upgraded to improve supply voltage. Tie point shifts will be used to maintain adequate voltage in the Waipiata area.

Constraint	Description	Intended remedy
		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.
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 renewal will be considered on a case-by-case basis
Environmental – Oil	Expectation of no significant oil spills from any substation	Install oil bunding and separation systems at remaining substations
Coastal Marine	Increased corrosion of substation equipment due to salt pollution	Relocate substations further away from coast where economically viable (for example Merton, Palmerston, Waitati) and/or enclose substation equipment inside buildings (Owaka, Port Molyneux).
Coastal Marine	Increased corrosion of overhead lines Salt pollution reducing insulation effectiveness	Use high-spec (corrosion resistant) conductor near coast Over-insulate lines near coast

The most significant issue arising from the estimated demand in section 4.2 is the capacity shortfall and the requirement for the replacement and upgrade of the transformer at the Patearoa substation. Rapid load growth, driven by the adoption of spray irrigators to comply with district council rules, requires the transformer upgrade to be completed in time for the 2016/17 irrigation season.

The same council rules apply to Gimmerburn to the north and west of Patearoa, and Waipiata to the northeast; and therefore future rapid irrigation-related growth is these areas is considered to be highly likely. The longer term regional solution will see Patearoa substation converted to a dual transformer site with sufficient capacity to accommodate this load growth. A 33 kV ring supply arrangement will be installed to provide power at N-1 security to both Patearoa and Waipiata substations. An extra Patearoa feeder will be installed heading north into the Lower Gimmerburn area. This is discussed more fully in section 4.4.

4.4. Development Programme

4.4.1. Current Projects

New Connections and Easements

The Customer Connections line items are an allowance for new connections to the network other than large development projects. Each specific solution will depend on location and consumer requirements. Some subdivision developments are occurring but we receive little or no prior notification of these. Requests to Developers and Regional Authorities provided only minimal information on subdivisions occurring.

The budgeted cost of $1.26M p.a. (Consumer Connection) is based on past experience and known development has been included in the plan.

A modest allowance has been made to connect Distributed Generation to the network. A budgeted cost of $12k p.a. (System Growth) is made for new easements and is based on past experience.

Major New Connections Projects

Rapid growth areas as described in section 4.2.2 require a corresponding expansion of the local distribution network. The rate of expansion is somewhat unpredictable as the timing and speed of developments are largely driven by commercial factors outside of OJV's ability to monitor.

$2-3M p.a. has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approx. $1.25M p.a. in the medium to long term where the location and/or scale of projects is relatively unknown.

Clydevale Transformer Upgrade and New Switchgear

Increasing loads from new irrigation are now pushing the load capacity of the existing single transformer and there is limited load transfer ability away from the substation. In addition there are concerns with the condition and reliability of the old KFE outdoor circuit breakers. The project is to install a new 5 MVA transformer and place new indoor 11 kV switchgear.

Available options include

- Replace the transformer but keep the existing switchgear.
- Place dual transformers to meet the security criteria.
- No non-asset solutions available.

A replacement transformer is required for load growth. Replacing the old 11 kV CBs at the same time as the transformer replacement is the lowest cost option in the long term.

$1.5M in total has been budgeted under System Growth. The project was targeted for completion in the 2015/16 financial year; however the failure of the original site transformer has delayed some aspects of the project, causing approx. $870k of carry-over into 2016/17.

Puketoi Area Upgrade

Accelerated load growth is occurring in the region due to spray irrigation and, to a lesser extent, dairy conversion. The Patearoa zone substation transformer is at the end of its nominal life. The nearby Waipiata feeder has voltage issues arising from load growth that could be solved by a tie point shift, if sufficient capacity were available at Patearoa.

An initial review indicated a requirement for a new zone substation; however a more detailed analysis has shown that the extra load can be supported more economically off an upgraded Patearoa zone substation using 11 kV voltage regulators.

Available options include

- Develop a new zone substation at or near Puketoi off the 66 or 33 kV lines.
- Upgrade Patearoa substation capacity and maintain feeder voltage via:
  - Field regulators, or
  - Reconductoring, or
  - 22 kV conversion.
- No non-asset solutions available.

The most economic option is to upgrade Patearoa substation capacity and install field regulators as load grows. $1.6M over two years is budgeted under System Growth. The upgrade is planned to be completed in time for the 2016/17 irrigation season.

Chrystalls Beach SWER line upgrade

Load growth on the Elderlee 1 feeder is starting to cause voltage issues at the coastal settlements of Chrystalls Beach and Bull Creek. These coastal settlements are at the end of a stretch of light SWER line that is now exposed to 7.5 A peak load current. The bulk of the voltage drop occurs over this SWER line. The SWER line is old and in poor condition.

Available options are to refurbish the SWER line and:

- Supply settlements along the coast from Toko Mouth via 3-phase upgrade, or
- Upgrade SWER conductor to Flounder, or
- Install battery bank near the coast for peak shaving, or
- Install generator near the coast for peak shaving, or
- Install SWER regulator
- No non-asset solutions.

Replacing SWER conductor to Flounder offers an efficient means of improving the voltage without undue incremental cost.

$336k has been allocated over 2016/17/18 under System Growth to improve voltage to customers whilst restoring the condition of the SWER line.

Remarkables Substation

The land that the Remarkables Substation is built on is the subject of an agreement to purchase, but the purchase has not yet been completed due to delays in the subdivision process. These issues are expected to be resolved in the short term.

The existing internet-based communications from the substation is prone to failure and an improved communications system is warranted.

$538k has been allocated over 2016/17/18 under System Growth to fulfil the agreement for land purchase and establish more reliable communications to the site.

Barnego Rd Subtransmission Upgrade

Load growth has led to a length of subtransmission line between Balclutha GXP and the Charlotte St substation exceeding its rated current at maximum demand and when the other Charlotte St/ Balclutha GXP line is out of service.

While most of the subtransmission conductor between Balclutha GXP and Charlotte St substation is Cochin or Hare, a short length of one line is constructed with lighter Raven conductor. This conductor exceeds its current rating when required to pass the full Charlotte St maximum demand.

A workaround exists in that Charlotte St can be partially backfed via Finegand with current load levels and protection settings. However the Raven conductor is an unnecessary weakness that can be removed from an otherwise strong subtransmission network at minimal cost.

Available options include

- Do nothing and continue to backfeed via Finegand when subtransmission faults require.
- Reconductor to Hare or equivalent

Reconductoring results in a stronger, simpler network at minimal cost.

$59k is budgeted under System Growth to remove a vulnerability to conductor overloading without unnecessary complication to system operation or protection setting. The project is scheduled for completion by 2019.

Gimmerburn Area Upgrade – Substation Upgrade and Lines

The abrupt load growth in the Puketoi area (see above) is largely driven by Otago Regional Council initiatives promoting more water-efficient (but more electrically demanding) irrigation schemes. The same initiatives apply to similar land in the Gimmerburn area some 15 km to the north. A similar level of load growth is therefore expected in the Gimmerburn area in the short to medium term.

An initial review indicated a requirement for a new zone substation; however a more detailed analysis has shown that the extra load can be supported more economically off an upgraded Patearoa zone substation. At this point the load on Patearoa would be sufficient to justify upgrade to an N-1 level of security. This upgrade involves conversion to a dual transformer site, completion

of a subtransmission ring between Patearoa/ Ranfurly/Waipiata zone substations, and installation of a new Patearoa feeder to feed the Gimmerburn area.

Available options include

- Support the load from the existing substations (but the ability for this is limited).
- Reinforce feeders from existing substations to supply the load
- Develop a new zone substation on Maniototo Rd off the 66 kV line.
- Upgrade Patearoa substation capacity and security, and connect a portion of the Gimmerburn load to Patearoa. The most efficient approach would have the side effect of improving security of supply to the Waipiata 33 kV bus to N-1.
- No non-asset solutions.

Upgrading Patearoa substation to supply Gimmerburn is the only option that keeps zone substation 11 kV busbar security in the area at acceptable levels.

$3.95M is budgeted under System Growth. The timeframe of the project is dictated by actual Gimmerburn load growth. According to current projections the upgrade will occur over 2019-2021.

11 kV Reclosers and SCADA Automation

Reliability improvement may be economically provided by the installation of line reclosers that automatically sectionalise lines under fault conditions, thereby restoring service to unaffected parts with only momentary interruption.

The 11 kV network is largely radial with few feeder interconnections, and any faults on the feeder interrupt all customers on the feeder until the fault is found and repaired.

The installed cost of reclosers is approximately $50k each which provides relatively cheap reliability improvement. On feeders with no downstream tie point a communications-free sectionaliser will provide only slightly lower benefits at a cost of approx. $30k each.

The opportunity also exists to replace existing old, unsupported hydraulic SWER reclosers on the network.

Available options include

- Do nothing and continue with the current reliability performance.
- Install reclosers where they are economically viable and replace end-of-life reclosers
- No non-asset solutions available.

Install reclosers where they are economically viable including SCADA modifications.

$1.6M is budgeted over five years under Quality of Supply. Planned timeframe for installation is 2015-19.

Quality Remedies

Various works to remedy poor power quality usually identified from voltage complaint investigations and where an appropriate solution is identified including:

- Installation of 11kV regulators.
- Up-sizing of components (conductor, transformer).
- Demand side management.
- Power factor improvements. (Ensuring consumer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring consumers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring consumer equipment is working and configured appropriately.)

An on-going budget of $179k p.a. has been allocated under Quality of Supply.

Surge Arrestor Replacement due Transpower NER

Many existing subtransmission-voltage surge arrestors are chosen to operate at less than the line-to-line voltage of the circuit. This selection of rating maximises the extent to which lightning surges are "clipped", thus minimising voltage stress on the protected equipment.

However Transpower are installing 33 kV NERs at the Balclutha GXP. The presence of an NER means that downstream surge arrestors can be legitimately held at line-to-line voltage for the maximum fault clearing time of the GXP feeder protection system.

Each surge arrestor at risk of inappropriate operation must therefore be replaced with a new unit with a higher rating. A 2015 analysis has shown that most affected surge arrestors will operate correctly with the NER installed, but a few require replacement.

Available options include

- Accept occasional inappropriate surge arrestor operation
- Replace surge arrestors

Replacing at-risk subtransmission surge arrestors with models having a rating appropriate for an upstream NER is the most appropriate solution. $47k has been budgeted under Reliability to replace the vulnerable surge arrestors in 2016.

Elderlee St Arc-Flash Upgrade

The Elderlee St substation has the only indoor switchboard on the network that has not yet had arc-flash protection installed. Arc flash hazards present a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

Available options include

- 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.

$118k has been budgeted for this project under Safety in the 2016/17 year.

Feeder Protection Upgrade for Minimum Fault Level

When a fault occurs and a failure is experienced in the primary protection, the secondary protection must be sufficiently sensitive to isolate the fault at the minimum possible fault level. Feeder extensions, reconfigurations, etc. can reduce the minimum fault level below levels that can be adequately covered by existing protection.

A protection review has identified two feeders where backup protection may not operate reliably if a fault occurs at minimum fault level. The minimum fault current is too low to be able to eliminate the problem simply through adjusting protection settings on existing devices.

Available options include

- Install new recloser to take on the role of secondary protection
- Install used but serviceable KFE recloser to take on the role of secondary protection
- Install fuses on problem laterals to take over the role of primary protection
- Upgrade conductor to increase minimum fault level
- No non-asset solutions.

Installing a used KFE recloser provides good protection at minimal material charge.

$44k has been allocated in 2016/17 under Safety to install sufficient reclosers that backup protection on the distribution network operates reliably for all fault levels.

Substation Structure Seismic Upgrades

A structural report has identified a number of substation buildings and outdoor structures that do not meet current building structural requirements under earthquake loading. There will be a range of work required at many substations, with the work prioritised and planned for completion over the next five years. More detailed engineering work is required to plan the remedial work noting that:

- There will be options for improving the building and structure integrity and each substation will require investigation and recommendations for consideration.
- As well as improving the strength of existing structures, consideration must be given to the age of the structures and their possible future replacements with indoor equipment.
- No non-asset solutions are available.

$1M has been allocated over 4 years with initial design work to be completed in 2016/17.

Substation NER Installation

As part of compliance with the new 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 new 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.

Available options include

- Do nothing and accept the higher overall cost of building distribution earths compliant with the EEA Guide.
- Install Petersen Coils and carry out the necessary network upgrades to allow sustained operation with phase-ground voltage at phase-phase levels.
- Install NERs.
- No non-asset solutions.

The NER installation is considered to provide the best cost-benefit ratio.

$1.7M is budgeted over seven years under Safety, including design work undertaken in 2015/16.

33 kV Transformer Circuit Breakers

Two out of seven 5MVA transformers do not have 33 kV circuit breakers for transformer protection at present, and rely on 33 kV fuses only. None of the 15 smaller 2.5 MVA transformers have 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.

The 33 kV breakers were originally planned to be installed 2020-25 and were listed in the 2015 AMP as a contingent project. However the timeframe of the NER programme and the reliance of transformer fusing on solid earths has brought forward the project timeframe.

Available options include

- Retain fuses, do not install NER, and accept the do-nothing consequences of the NER project
- 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 33 kV CBs and differential transformer protection

- No non-asset solutions.

Installing circuit breakers protects the transformer whilst permitting installation of an NER.

$203k p.a. has been budgeted over 6 years under Safety for a staged implementation in tandem with the NER project.

Milton 33 kV Ring Protection Upgrade

The 33kV ring feed switching design from Balclutha through Glenore and Kiness only provides N-1 reliability to Elderlee Street but not to other substations teed off it. The present protection only uses directional protection relays and there have been some spurious openings of the ring in association with other faults.

A replacement system would have greater selectivity using end to end communications. The load and importance in the adjacent substations has grown and now includes the 7.65MW wind farm connection and the new Milburn substation which would benefit from an enhanced protection scheme.

Available options include

- Reroute Milburn supply to be fed directly from Elderlee St substation rather than Kiness. Install circuit breakers with distance protection on the Balclutha/Milton/ Glenore ring.
- Install distance relays only at the new Elderlee Street substation.
- Do nothing and accept nuisance trips that reduce reliability and result in voltage disturbances and/or actual loss of supply.

The enhanced protection system will yield the full reliability potential from the line assets employed which alternative options will not.

$347k has been budgeted under Reliability to improve network robustness toward 33 kV line faults. Target for completion is 2018.

Clydevale 33 kV Ring

The load and customer numbers in the Clydevale area are increasing with highlighted importance on a reliable supply to the individual dairy farms and the Gardians diary factory.

There are two 33 kV lines supplying Clydevale via Greers and Clifton respectively, with the first line having a tee off to supply the Greenfield substation. The second line is in poor condition, is not reliable as a backup and only has basic manual switching involving hours of driving to achieve restoration after a fault on one line.

This project is to upgrade the switching configuration and ring protection around the Clydevale and Greenfield dairy factory to make the network more robust to single 33 kV line faults.

Available options include

- Replace manual switches at Clifton, Greers, Clydevale and Greenfield with SCADA operated circuit breakers for timely restoration, one line at a time.

- Extend the circuit breakers with additional directional protection and run the ring closed for resilience to the first fault.
- Do nothing and accept worsening SAIDI and SAIFI figures and increasingly unhappy customers.
- No non-asset solutions.

Upgrading the ring protection yields the most reliability from the existing 33 kV network in the area. Network performance will be increased with better SAIDI and SAIFI results. The closed ring will reduce losses and improve quality of supply to all customers in the area.

$463k is budgeted under Reliability. The project is targeted for completion by 2022.

4.4.2. Considered Projects

Expected projects for year six to ten (YE 31 March 2021 to 2026) are as follows. These projects have little if any certainty.

Note that some projects that are on-going throughout this period are detailed above.

Palmerston Substation Rebuild Taieri Peak Rd

The Palmerston 33/11 kV substation has dual transformers but is only supplied by a single 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 controls and ripple injection plant are within the contractor's depot building.

Available options include

- Relocate Palmerston zone substation to newly acquired Palmerston 110/33 kV substation.
- Keep the existing substation and route a second 33 kV incomer.
- No non-asset solutions available.

Relocation of the substation allows for increased supply security whilst addressing the condition and safety issues of the existing substation.

$2.32M is budgeted under Asset Replacement and Renewal. The project is currently scheduled for completion by 2023 however this timeframe may be deferred if higher priority (e.g. growth-related) projects arise.

Waitati Zone Sub Relocation

Reliability for customers off the Waitati substation is the poorest on the network. The existing substation is flood prone and is located within a residential area. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply. Both the transformer and switchgear are approaching end of life although at present, condition testing is not indicating that end of life is imminent. Reconfiguration of the Palmerston GXP supply allows for redundant 33kV line circuits to be provided into Waitati.

Available options include

- Do nothing and continue with poor reliability due to 33kV line faults.
- Redevelop on the existing site to allow for the dual 33kV circuits.
- Redevelop on a new site.

Redeveloping on a new site is the best strategic solution with the lowest future risk. $3.05M has been allocated under Asset Replacement and Renewal for work over 2021/22/23, however the timing of the project is flexible and may be adjusted if projects with more urgent drivers (i.e. growth- or condition-driven projects) arise.

Elderlee St Switchgear Replacement

The 11 kV indoor switchgear at Elderlee St is approaching end of life.

The Elderlee St switchroom is one of the network buildings highlighted as requiring seismic reinforcement. However space within the switchroom is very tight and disrupted by concrete pillars, both of which are likely to complicate a traditional steel reinforcement seismic solution. Options for seismic reinforcement will be investigated however at this stage the most likely scenario is for a replacement switchroom to be built to 100% NBS to house the replacement switchgear.

As described under "Contingent Projects", future industrial load growth may require this substation to be relocated from its current site. The replacement switchroom would therefore be a "PortaCom" style building that can be easily relocated to the new site should the need arise.

Available options include

- Reinforce existing switchroom and replace switchgear
- Replace switchgear and switchroom
- No non-asset solutions

At this stage the replacement portable switchroom appears to offer the best combination of economy, seismic strength and futureproofing. This recommendation may change pending the outcome of a detailed seismic assessment on the existing switchroom.

$570k has been allocated under Asset Replacement and Renewal to replace the end-of-life equipment whilst ensuring adequate switchroom seismic strength and allowing for the possibility of a future relocation to a new site. Current target for completion is 2022.

4.4.3. Contingent Projects

The following contingent projects have been identified. In addition some customer related work may be expected from our largest current customers; for example requests for increased transformer or subtransmission line capacity. These have been excluded from OJV's spend plans until they been requested by the customer and have become certain.

Milton (Elderlee St) Substation

This substation feeding Milton had been approaching its N-1 capacity. However the capacity driver for an upgrade has been removed by the recent closure of timber mills in the area, combined with new load transfer capability from the construction of the Milburn substation to the northeast.

There have been indications that significant industrial expansion could take place in the Milburn area in the medium term. Should this expansion take place, the load transfer capability from Milburn substation will be reduced and capacity may again become a constraint upon Elderlee St substation.

This project has therefore become contingent upon sufficient industrial expansion in the area being confirmed.

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 substation building has been identified as below current building seismic strength requirements. The existing 33kV lines cross industrial land and the railway and future 33kV line easements for the 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.

With sufficient industrial growth, replacement on a new site becomes the best strategic solution with the lowest risk.

$4.43M would be allocated for this project under System Growth.

Palmerston Area Ripple Injection Plant

The plant is at the end of its service life with spares are no longer being supported and reliability is compromised.

The value of load control to OJV is doubtful given the change to the lower South Island regional demand grouping, however, the ripple receivers are owned by the retailer and are required for day/night rate switching, limiting other options.

The upcoming 33 kV reconfiguration in the area means the ripple signal will be too attenuated towards the Halfway Bush 33 kV bus and so the ripple plant injection point must be re-located.

Recent developments have raised the possibility that smart meters and/or load interruption relays controlled by the smart meter network may be able to be installed throughout the Palmerston area within the remaining life of the ripple plant.

The feasibility of the smart meter solution will not be able to be confirmed within the planning year. The ripple plant replacement is contingent upon the smart meter solution proving not to be feasible.

Available options include

- Install replacement ripple plant at the future Waikouaiti substation.
- Consider if replacement is justified as the main benefactor is the Retailer with their receivers being used more to control tariff options rather than the Network controlling load.
- Consider alternatives to ripple injection for load control in association with smart meters. Consider daylight switches for the main network use to control street lights.

A replacement ripple plant will be installed if a smart meter solution proves infeasible.

$510k would be allocated under Asset Replacement and Renewal for this project.

Clydevale Ring Reinforcement

There have been indications that significant industrial expansion requiring supply at 33 kV could occur in the Clydevale area in the medium term.

The existing subtransmission network in the area is incapable of delivering this extra load. Approximately half the Clydevale Ring will require reinforcement should the industrial expansion take place.

Available options include

- Reinforce Clydevale ring
- No non-asset solutions

$1.15M would be allocated for this project under System Growth.

Waitati Tee Reinforcement

The Waitati Tee was recently built to provide one branch of an N-1 security of 33 kV supply to a point just north of the Waitati substation. The other branch is the original 33 kV line from Merton.

The Merton substation replacement project, scheduled for completion in 2020, will reuse this 33 kV line from Merton at 11 kV – thus removing one branch of the Waitati N-1 supply. By that time the second 110 kV line between Halfway Bush (HWB) and Palmerston (PAL) will have been converted to 33 kV, offering a second source of 33 kV supply in the Waitati area.

The Waitati substation relocation will ultimately utilise both HWB-PAL lines for an N-1 supply, and is currently scheduled for completion in 2022. However until condition testing uncovers condition-based drivers for replacement, the Waitati relocation will be driven only by reliability and calendar age of assets, and may be delayed if projects with more urgent drivers (i.e. growth- or condition-driven projects) arise.

Should it become apparent that the Waitati relocation will be delayed significantly beyond the Merton replacement, Waitati Tee reinforcement is required to preserve N-1 reliability of supply to Waitati using the second HWB-PAL line.

Available options include

- Connect HWB-PAL 2 to the Waitati Tee to preserve N-1 supply to the tee point after the completion of the Merton relocation
- Do nothing and accept reduced reliability to the tee point after the completion of the Merton relocation

HWB-PAL 2 will be connected to the Waitati Tee if it becomes apparent that the period of reduced reliability will be extended. $80k would be allocated under Reliability for this work.

4.5. OJV's Forecast Capital Expenditure

The forecast capital expenditure for OJV is shown in Table 36. These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 36: OJV's Forecast Capital Expenditure

CAPEX: Consumer Connection ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Customer Connections (≤ 20kVA)	249	249	249	249	249	249	249	249	249	249
Customer Connections (21 to 99kVA)	482	482	482	482	482	482	482	482	482	482
Customer Connections (≥ 100kVA)	527	502	502	502	502	502	502	502	502	502
Major New Connections Projects	3,294	2,030	3,140	1,250	900	1,250	1,250	1,250	900	1,250
	4,553	**3,264**	**4,374**	**2,484**	**2,134**	**2,484**	**2,484**	**2,484**	**2,134**	**2,484**

CAPEX: System Growth ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Clydevale transformer upgrade and new switchgear	871									
Puketoi Area Upgrade	980									
Chrystalls Beach SWER line upgrade	168	168								
Remarkables Sub	150	388								
General ESL MV Network Growth	250		250							
Barnego Rd subtransmission upgrade			59							
Gimmerburn Area Upgrade - substation upgrade and lines				1,920	2,032					
Easements	12	12	12	12	12	12	12	12	12	12
Unspecified System Growth Projects								1,313	1,313	1,313
	2,431	**568**	**321**	**1,932**	**2,044**	**12**	**12**	**1,325**	**1,325**	**1,325**

CAPEX: Asset Replacement and Renewal ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
LV Line Replacement and Renewal	758	783	783	783	783	783	783	783	783	783
SWER Line Replacement and Renewal	626	522	522	522	522	522	522	522	522	522
11 kV Line Replacement and Renewal	2,660	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133	3,133
33 kV Line Replacement and Renewal	1,454	1,977	1,977	2,089	2,089	2,089	2,089	2,089	2,089	2,089
HWB-PAL 2 110/33 kV Conversion			398							
Merton Substation replacement	195	774	1,849	1,977						
Glenore substation rebuild					561					
Owaka 11 kV switchgear replacement					306	306				
Port Molyneux 11 kV s/g replacement					404	202				
Clinton 11kV bus indoor conversion					306	306				
Palmerston Substation Rebuild						697	1,619			
Waitati Tee and future substation						1,010	2,044			
Elderlee St switchgear replacement						570				
Substation minor capital work	40	30	30	30	30	30	30	30	30	30
Unspecified Replacement & Renewal Projects								1,602	1,602	1,602
	5,733	**7,220**	**8,694**	**8,535**	**8,134**	**9,648**	**10,220**	**8,160**	**8,160**	**8,160**

CAPEX: Asset Relocations ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Network Chargeable	119	119	119	119	119	119	119	119	119	119
Unspecified Asset Relocation Projects						129	239	239	239	239
	119	**119**	**119**	**119**	**119**	**249**	**358**	**358**	**358**	**358**

CAPEX: Quality of Supply ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Reclosers with SCADA integration	239	358	358	358						
Misc Quality of Supply Upgrades	179	179	179	179	179	179	179	179	179	179
Unspecified Quality of Supply Projects						239	239	239	239	239
	418	**537**	**537**	**537**	**179**	**418**	**418**	**418**	**418**	**418**

CAPEX: Legislative and Regulatory ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

CAPEX: Other Reliability, Safety and Environment ($000)	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Surge arrestor replacement	47									
Elderlee St arc-flash upgrade	118									
Feeder protection upgrade for minimum fault level	44									
Substation clearances/fence improvements	235	235								
Substation structure seismic upgrades	60	353	353	251						
Substation NER installation	418	239	239	239	239	239				
33 kV Transformer Circuit Breakers	203	203	203	203	203	203				
Milton 33kV ring protection upgrade		347								
Clydevale 33 kV ring rebuild and protection					116	347				
Replacement of OH structures with Ground Mounted	179	179	179	179	179	179	179	179	179	179
Earth refurbishment from earth testing	179	179	179	179	179	179	179	179	179	179
Unspecified Reliability/Safety/Environment Projects								716	716	716
	1,482	**1,736**	**1,153**	**1,051**	**916**	**1,147**	**358**	**1,074**	**1,074**	**1,074**

Total Network CAPEX	14,736	13,444	15,198	14,658	13,526	13,958	13,850	13,819	13,469	13,819

4.6. Distributed Generation Policy

The value of distributed generation can be realised 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.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and OJV is actively encouraged. The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings, with a guideline and application forms available on the web at http://www.powernet.co.nz/dg-guide.

4.6.1. Connection Terms and Conditions (Commercial)

- Connection of up to 10kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10kW 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, will be recognised and shared provided that the distributed generation is of sufficient size to provide real benefits.
- 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.

4.6.2. 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.

4.6.3. 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 10kW 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.

In building the demand model for planning purposes the impact of Distributed Generation has been ignored, due to the expected low connection rate and the probability that only a small percentage of this capacity will be available during peaks.

4.7. Non-Network Development

OJV receives IT and management services support through its management services contract with PowerNet. Whilst it does not directly develop the GIS (Intergraph) or AMS (Maximo) systems, it does in conjunction with PowerNet develop interfaces and processes around these systems. In particular, it is currently developing both inspection templates for condition assessment, the IT tools to efficiently implement inspections in the field and automatically upload that data, and the processes for using and updating that data. These systems and processes are considered critical to progressing OJV's asset management strategies and strengthening its risk management and capital governance systems.

4.8. Use of Non-Network Solutions

As discussed in section 4.1.4 the company routinely considers a range of non-asset solutions and indeed OJV's preference is for solutions that avoid or defer new investment.

Effectiveness of tariff incentives is lessened with Retailers repackaging line charges that sometimes removes the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels.

Load control is utilised to control:

- 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 an occasional reduction of their load instead of investing in additional network assets.

Generators (owned by PowerNet) are routinely used to minimise the impact of significant planned outages on the OJV network.

The future acquisition of a mobile substation by The Power Company (which will be made available to OJV on a rental basis) raises the threshold at which OJV justifies converting a single-transformer substation to a dual-transformer site; resulting in significantly deferred growth-related investment on the larger single-transformer substations.

Where the nature of the load and network permit, stand-by generators and network storage solutions (batteries) are considered as an alternative to line upgrades.

5. Lifecycle Planning

Development criteria, the subject of the previous section, determine the need for particular assets. Once this need has been established each asset must be managed throughout its lifecycle to allow the asset to continue to fulfil its purpose for as long as it is required, and to minimise any adverse effects the asset might create.

5.1. Lifecycle Asset Management Processes

Following procurement of equipment and materials, assets are constructed or installed in accordance with a design or network standard, and undergo a commissioning process to ensure the asset is capable of operating as intended. The asset then enters its useful service life where it will often be operated over a considerable time period. Maintenance activities are generally undertaken throughout an asset's operational life to support its continued reliable service for as long as it is economic to do so. At some point the asset will reach its end of life and will be retired from service. At that point the asset will be replaced (assuming the need remains) while the retired asset must be disposed of appropriately. This process is outlined in Figure 39 below.

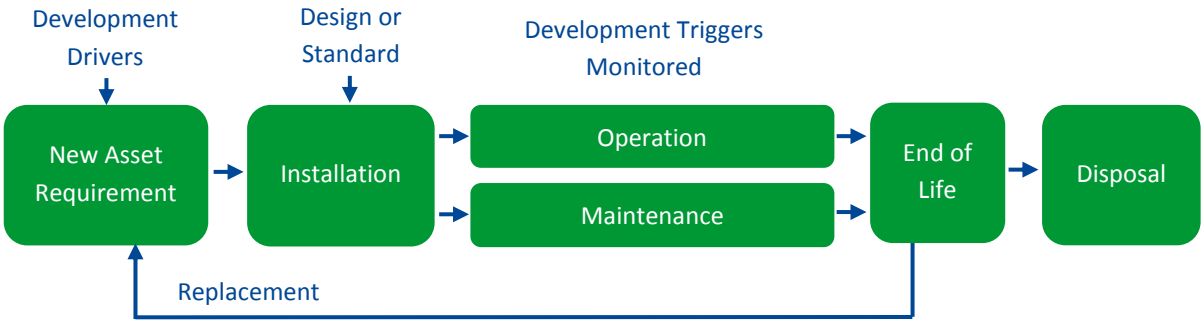

Figure 39: Asset Lifecycle

OJV follows several asset management procedures to manage network assets throughout these lifecycle stages, as referenced in Appendix 4.

5.1.1. Installing Assets

The drivers for installation of new assets are as explained in the development section. Similarly the drivers requiring an asset on the network may change during the asset's operational life, and so may change the viability of maintaining or replacing an asset. Therefore these drivers need to be monitored beyond the installation to ensure the overall objective of providing an efficient cost effective service is achieved.

More complex assets such as a zone substation will require substantial design work to be completed, while standards are used to guide the construction and installation of more routine tasks such as the installation of a distribution transformer. Equipment and materials are procured as per the design or standard to be implemented and in line with OJV's standardisation requirements (which are incorporated into designs and standards) as far as possible.

Assets are then installed to the design or standard followed by a commissioning process which is either specified in the design or (for standardised installations) using a commissioning checklist to ensure the asset has been installed and will function as intended prior to putting into service.

5.1.2. Operating OJV's Assets

Operation of OJV's assets predominantly involves simply letting the electricity 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.

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.

5.1.3. Maintaining OJV's Assets

Maintenance is primarily about replacing consumable components. Many of these components will be designed to "wear out" over 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 and loss or contamination of lubricants.

Continued operation of such components will eventually lead to failure as indicated in Figure 40. 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 – note that the horizontal axis in Figure 40 is not simply labelled "time".

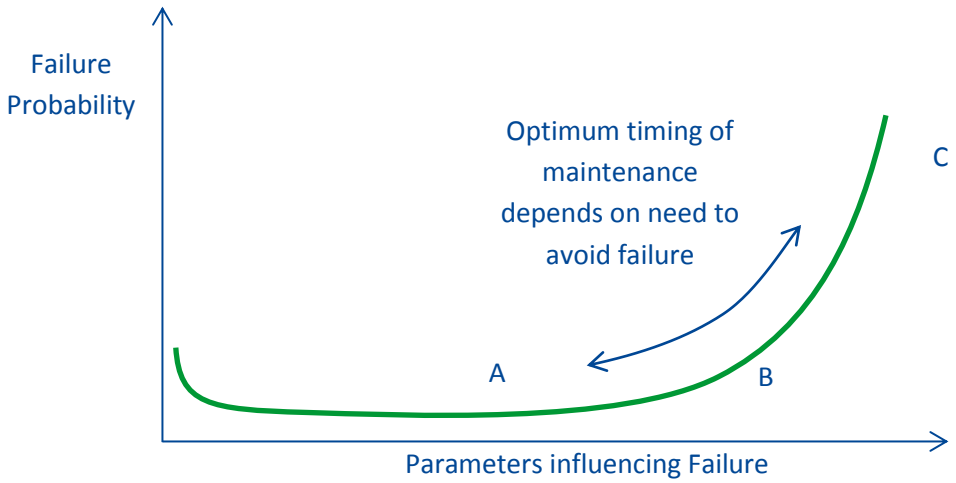

Figure 40: Component Failure

This probability of failure curve can also 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. Conversely 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.

Like all OJV's other business decisions, 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.

The practical effect of this is that assets supplying large customers or numbers of customers such as a 33/11 kV substation transformer may only be operated to point B in Figure 40 and condition will be extensively monitored to minimise the likelihood of supply interruption whilst assets supplying only a few customers such as a 10 kVA transformer will more than likely be run to failure represented as point C. In the extreme case of, say, turbine blades in an aircraft engine it would be desirable to avoid even the slightest probability of failure hence the blades may only be operated to point A.

Condition assessment is an important part of determining maintenance requirements as many components do not deteriorate at a predictable rate. This allows deferring maintenance cost for assets that survive in good condition and focusing maintenance around assets that have deteriorated at a faster rate. Condition assessment involves inspections and testing to gather information about the condition of assets and their components and generally incorporates follow up analysis to understand the results of these condition assessments such as establishing trends to predict when maintenance needs to occur.

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 of an asset and the need to avoid loss of supply both 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 actual component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

5.1.4. Replacement and Renewal of OJV's Assets

Renewals or refurbishments are more 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 bit like "Grandpa's axe"). This would be the typical approach for 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 for failures at distribution or subtransmission voltages) or when a "non-consumable" part of the asset has significantly aged or deteriorated, for example paper insulation in a transformer. The key factor being that it then becomes more cost effective to simply replace the asset.

5.1.5. Retiring and Disposing of OJV's assets

Retiring 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). Removed assets must be disposed of in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos. The asset will be removed from the regulatory asset base if required.

Key criteria for retiring an asset include:

- Its physical presence 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 becomes uneconomic to continue to maintain the asset as it is more cost effective to replace with a new asset.

5.2. Routine Corrective Maintenance & Inspection

Network assets are inspected routinely with the frequency dependent on the criticality of the assets and the outcome focussing on failure avoidance. 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 averted, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved), for example 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.

Inspections are practical for all assets, for example cables buried underground, and may be further limited by the availability of outages or the added effort (labour cost) required to remove covers. Therefore for the most part routine inspections are limited to what can be viewed from a walkover of the assets.

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. Testing may be destructive or non-destructive. For example insulation resistance (IR) testing gives an ohmic value for insulation under test whereas very low frequency (VLF) testing is "pass-fail" where a pass proves integrity of insulation but a fail indicates a fault which needs to be repaired.

5.2.1. OJV's Maintenance Approach

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; this maintenance is not routine at the asset level, 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 inspected and testing is generally not cost effective and difficult to obtain accurate results 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 relatively acceptable for lines and cables compared to the more technical assets. Significant serviceable life can be restored by repairing a fault due to the distributed nature of these assets and the relatively minor (i.e. localised) effect of faults. Asset criticality must allow for the occurrence of outages however increased security (redundancy) is often applied as more effective than attempting to determine time to failure and performing preventative maintenance.

Table 37 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 37: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	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
Zone Substations	Subtransmission Voltage Switchgear	Condition Monitoring 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 resistances, Insulation resistance, Function checks on auxiliary devices (Buchholz, pressure relief, thermometers). Predictive maintenance - oil analysis (dissolved gasses, 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 work at unit's 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 Operational counts Non-periodic
	Distribution Voltage Switchgear	Condition Monitoring 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

Asset Category	Sub Category	Maintenance Approach	Frequency
	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.	Monthly
		Protection relays are tested typically with current injection to verify operation as per settings.	5 yearly
		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.	Non-perodic
Distribution Network	O/H	Condition Monitoring through periodic visual inspection.	5 yearly
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Generally run to failure and repair.	Reactive or opportunistic
		Inspection of visible terminations as part of zone substation checks, sheath insulation IR tested, and otherwise opportunistic inspection if covers removed for other work.	5 yearly if visible
		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.	
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection.	5 yearly
		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.	
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections.	6 monthly
		Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated.	(or 5 yearly if <150Kva)
		Winding resistances, Insulation resistance if shut down allows.	Opportunistic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to 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.	6 monthly
		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.	5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. O/H structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection.	5 yearly
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Run to failure and repair.	Reactive

Asset Category	Sub Category	Maintenance Approach	Frequency
	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
	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

5.2.2. Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 38 and forecasts are provided in Table 41 at the end of this section. 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.

Table 38: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Line Condition Survey	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on overhead line assets.	Cost $0.5-1M on-going; OPEX
Distribution Minor Maintenance	Generally reactive work undertaken to correct issues found on distribution lines during the routine line condition survey. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
Zone Substation Minor Maintenance	Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays. Also a general budget for all minor technical work.	Cost Under $0.5M on-going; OPEX
Voltage Complaint Investigation	Investigations into supply quality which are generally customer initiated.	Cost Under $0.5M on-going; OPEX
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.	Cost Under $0.5M on-going; OPEX
Earth Testing and Review	Routine testing of earthing assets and connections to ensure safety and functional requirements are met. Completed five yearly (20% annually).	Cost Under $0.5M on-going; OPEX

Budget	Description	Expenditure Range/Type
Load Control Equipment **Radio Equipment** **SCADA Equipment**	Routine inspection and testing of the applicable substation equipment	Cost Under $0.5M on-going; OPEX
General Zone Substation Maintenance	Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups.	Cost Under $0.5M on-going; OPEX
Earth Testing	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed five yearly, next due 2017/18.	Cost Under $0.5M 2017/18 and five yearly thereafter; OPEX

5.2.3. Systemic Faults

Examples of past investigations and outcomes are shown below. Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to the OJV network.

- Kidney strain insulators: Replaced with new polymer strains.
- DIN LV fuses: Sourced units that can be used outdoor.
- Parallel-groove clamps: Replaced with compression joints.
- Non-UV stabilised insulation: Exposed LV now has sleeve cover, with new cables UV stabilised.
- Opossum faults: Extended opossum guard length.

5.3. Asset Replacement and Renewal

The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to 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 the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their nominal 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 lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions. Replacement of assets may also be heavily influence by the development drivers discussed in section 4.1.

Table 39 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 39: Replacement and Renewal Decisions by Asset Category

Asset Category	Sub Category	Replacement and 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	Cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Sub Transmission Voltage Switchgear (ABSs)	Replacement when inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Sub Transmission 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 and Regulators	Replacement after a failure causing significant damage that is not economic to repair. Paper, Furan or DGA analysis indicating insulation at end of life. Tank and fittings deteriorating, lack of spare parts and not economic to maintain for aged units. Not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit.
	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

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		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	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 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 <100kVA and older than 20yrs are scrapped; other units testing satisfactory recycled as spares.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	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	RTU/Radio 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.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
	Ripple Plant	Run to failure with redundant coupling cells at Ranfurly and Palmerston and spares available for converters

5.3.1. Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are listed below; these often represent one-off replacement or renewal of significant assets that have reached end of life or a significant milestone in its life. Other projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

The expenditure forecasts for these budgets are provided in Table 36 (CAPEX) and Table 41 (OPEX).

Halfway Bush-Palmerston Second 33 kV Conversion

The configuration of the pre-existing northern 33 kV network towards Dunedin was less than optimal with the lowest reliability being effectively at the end of the OtagoNet network, yet at the closest point to the Halfway Bush point of supply.

An opportunity arose to purchase the two Transpower Halfway Bush-Palmerston lines at a fair price to enable OJV to further develop or modify the supply to increase reliability and efficiency, both of this point of supply and the downstream 33 kV network and zone substations. A large part of these gains were to arise from shifting the point of supply to Halfway Bush and converting these 110kV lines to 33 kV, which allows a redundant 33 kV supply into zone substations supplying Waitati and Waikouaiti.

The first stage was to convert one of the 110 kV lines to 33 kV and this work has already been completed. The second stage is to convert the second line to 33 kV. The conversion must be undertaken in two stages because until Transpower upgrade the Halfway Bush 33 kV bus, scheduled for completion in 2018, they are unable to supply both lines at 33 kV.

$398k is budgeted as CAPEX under Asset Replacement & Renewal. The conversion will occur immediately after Transpower complete the conversion of their Halfway Bush bus; this work is currently scheduled for 2018.

Merton Substation Replacement (Waikouaiti)

The present Merton substation feeding the Waikouaiti area is reaching the N-1 capacity of the transformers, and the 11kV and 33kV structures have deteriorating wooden poles and components. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply.

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.

A further opportunity exists with the recent purchase of the Transpower 110kV lines that run past this substation, allowing for improved security of supply and reduced losses with more direct supply than the existing configuration.

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.

$4.8M is budgeted as CAPEX under Asset Replacement and Renewal with the project planned for completion in 2020. However the substation cannot be completed until the second Halfway Bush-Palmerston line 33 kV conversion (below) has been carried out.

Glenore Transformer, Oil Containment and Overhead Structure

The existing substation transformer is the oldest on the network (although it is not currently showing signs of pending failure) and is not currently bunded. The 11 kV overhead structure is also ageing and has seismic concerns. The 33 kV bus will be required to support extra breakers under the transformer fuse replacement project and the Milton Ring project.

Available options include

- Install replacement 2.5 MVA transformer on bund to contain any oil spill. Replace seismically vulnerable 11 kV bus with indoor switchroom. Install 33 kV CB on transformer incomer.
- As above but replace the transformer with 1.5 MVA only and replace it with 2.5 MVA as required by load growth. Nonstandard size and cost differential between units small, so not supported.
- As per first bullet point but rebuild the 11 kV overhead structure and install outdoor circuit breakers on the same site. Cost likely to be higher than standardised indoor solution, with no increased safety or environmental benefits.
- As per directly above but retain the existing single 11 kV feeder rather than splitting the feeder which requires a more complex bus.
- Decommission substation, upgrade the interconnecting 11kV lines from Lawrence, Milton and Kaitangata and provide additional voltage regulation. Implementation costs similar but lower benefits with higher losses and worse reliability.
- Rebuild on a new site (which has been identified) away from the river.
- No non-asset solutions.

From a financial perspective the case for decommissioning the substation vs replacing the transformer and retaining the single 11 kV feeder is about even. However replacement and retention of the single feeder offers superior SAIDI/SAIFI performance and greater capacity in the area, and is therefore the preferred option.

$561k (excluding the Transformer which has already been purchased) is budgeted as CAPEX under Replacement and Renewal. Timing is flexible as a full backfeed option exists; current planning is to complete work in 2021.

Owaka 11 kV Indoor Switchgear

The outdoor switchgear and bus arrangement is at end of life, has seismic strength and clearance issues and may require additional land for the substation to give adequate clearance to the fences if it was retained. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution.

Available options include

- Replace with new outdoor switchboard
- 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. Cost $612k as CAPEX under Asset Replacement and Renewal – target completion 2022.

Port Molyneux 11 kV Indoor Switchgear

The outdoor switchgear and bus arrangement is at end of life, has seismic strength and clearance issues and may require additional land for the substation to give adequate clearance to the fences if it was retained. The coastal location increases the vulnerability of the outdoor switchgear to corrosion and salt pollution.

Available options include

- Replace with new outdoor switchboard
- Replace with new indoor switchboard
- Redevelop on a new site
- 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. Cost $606k as CAPEX under Asset Replacement and Renewal – target completion 2022.

Clinton 11 kV Indoor Switchgear

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. Available options include

- Replace with new outdoor switchboard
- 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. Cost $612k as CAPEX under Asset Replacement and Renewal – target completion 2022.

Palmerston Substation Rebuild Taieri Peak Rd

The Palmerston 33/11 kV substation has dual transformers but is only supplied by a single 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 controls and ripple injection plant are within the contractor's depot building.

Available options include

- Relocate Palmerston zone substation to newly acquired Palmerston 110/33 kV substation.
- Keep the existing substation and route a second 33 kV incomer.
- No non-asset solutions available.

Relocation of the substation allows for increased supply security whilst addressing the condition and safety issues of the existing substation.

$2.32M is budgeted as CAPEX under Asset Replacement and Renewal. The project is currently scheduled for completion by 2023 however this timeframe may be deferred if higher priority (e.g. growth-related) projects arise.

Waitati Zone Sub Relocation

Reliability for customers off the Waitati substation is the poorest on the network. The existing substation is flood prone and is located within a residential area. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply. Both the transformer and switchgear are approaching end of life although at present, condition testing is not indicating that end of life is imminent. Reconfiguration of the Palmerston GXP supply allows for redundant 33kV line circuits to be provided into Waitati.

Available options include

- Do nothing and continue with poor reliability due to 33kV line faults.
- Redevelop on the existing site to allow for the dual 33kV circuits.
- Redevelop on a new site.

Redeveloping on a new site is the best strategic solution with the lowest future risk. $3.05M has been allocated as CAPEX under Asset Replacement and Renewal for work over 2021/22/23, however the timing of the project is flexible and may be adjusted if projects with more urgent drivers (i.e. growth- or condition-driven projects) arise.

Elderlee St Switchgear Replacement

The 11 kV indoor switchgear at Elderlee St is approaching end of life.

The Elderlee St switchroom is one of the network buildings highlighted as requiring seismic reinforcement. However space within the switchroom is very tight and disrupted by concrete pillars, both of which are likely to complicate a traditional steel reinforcement seismic solution. Options for seismic reinforcement will be investigated however at this stage the most likely scenario is for a replacement switchroom to be built to 100% NBS to house the replacement switchgear.

As described under "Contingent Projects", future industrial load growth may require this substation to be relocated from its current site. The replacement switchroom would therefore be a "PortaCom" style building that can be easily relocated to the new site should the need arise.

Available options include

- Reinforce existing switchroom and replace switchgear
- Replace switchgear and switchroom
- No non-asset solutions

At this stage the replacement portable switchroom appears to offer the best combination of economy, seismic strength and futureproofing. This recommendation may change pending the outcome of a detailed seismic assessment on the existing switchroom.

$570k has been as CAPEX allocated under Asset Replacement and Renewal to replace the end-of-life equipment whilst ensuring adequate switchroom seismic strength and allowing for the possibility of a future relocation to a new site. Current target for completion is 2022.

Decommissioning Works

The development programme for OJV includes the relocation of two substations that are approaching end of life and are in suboptimal locations. After completion of the relocation, the former substation sites must be decommissioned and restored to their original condition. Any lines made redundant by the shift should similarly be removed. The cost of this work appears as operational expenditure in the network budget.

It should be noted that the existing site for a third future relocation, Palmerston, will not require decommissioning due to its dual use as a depot and yard.

Estimated costs:

- $495k decommissioning of Merton substation and associated 33kV supply lines
- $54k decommissioning of (compact) Waitati substation

as OPEX under Asset Replacement and Renewal.

5.3.2. Ongoing Replacement and Renewal Programmes

The remaining replacement and renewal budgets are for ongoing work that tends to require about the same expenditure year after year. These budgets are listed and described in Table 40 and expenditure forecasts are provided in Table 36 (CAPEX) and Table 41 (OPEX).

Table 40: Replacement and Renewal Programmes

Budget	Description	Expenditure
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.	Over $5M on-going; CAPEX
Substation Minor Capital Work	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	Annual CAPEX Cost Under $0.5M
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	Cost Under $0.5M on-going; OPEX
33 kV Pole Maintenance	A budget specifically allocated for maintenance arising from the accelerated inspection program on 33 kV poles	Cost Under $0.5M on-going; OPEX
Network Chargeable Maintenance	Maintenance carried out at least partially at customer expense, e.g. pole shifts or third-party damage repairs.	Cost Under $0.5M on-going; OPEX
Maintenance Identified on Distribution Line Survey	Covers priority maintenance works discovered during detailed condition inspections.	Cost Under $0.5M on-going; OPEX
Transformer Refurbishment	Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.	Annual CAPEX Cost Under $0.5M

5.4. OJV's Forecast Operational Expenditure

The forecast operational expenditure for OJV is shown in Table 41. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two further categories not described earlier complete OJV's forecasted operational expenditure budget as follows.

5.4.1. 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 most customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. This OPEX cost is budgeted at $1.08M per annum.

5.4.2. Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Faults staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. This OPEX cost is budgeted at $0.98M per annum.

Table 41: OJV's Forecast Operational Expenditure

OPEX: Asset Replacement and Renewal	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Customer Connections Maintenance	7	7	7	7	7	7	7	7	7	7
33 kV Pole Maintenance	63	63	63	63	63	63	63	63	63	63
Network Chargeable Maintenance	33	33	33	33	33	33	33	33	33	33
Maintenance Identified on Distribution Line Survey	329	329	329	329	329	329	329	329	329	329
Transformer Refurbishment	66	66	66	66	66	66	66	66	66	66
Decommission Palmerston-Merton-Waitati Subtransmission Line				295						
Decommission Merton Substation				200						
Decommission Waitati Substation							54			
	497	**497**	**497**	**991**	**497**	**497**	**551**	**497**	**497**	**497**

OPEX: Vegetation Management	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Vegetation Management	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
	1,080	**1,080**	**1,080**	**1,080**	**1,080**	**1,080**	**1,080**	**1,080**	**1,080**	**1,080**

OPEX: Routine and Corrective Maintenance and Inspection	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Routine ESL Dist Insp Check & Mtce	5	6	8	9	10	11	13	14	15	16
MV Equipment Maintenance	5	6	8	9	10	11	13	14	15	16
Voltage Complaint Investigation	16	16	16	16	16	16	16	16	16	16
Transmission Line Minor Maintenance	13	13	13	13	13	13	13	13	13	13
Line Condition Survey	548	548	548	548	548	548	548	548	548	548
Earth Testing and Review	54	54	65	65	76	76	76	76	76	76
Load Control Equipment	7	7	7	7	7	7	7	7	7	7
Radio Equipment	33	33	33	33	33	33	33	33	33	33
SCADA Equipment	1	1	1	1	1	1	1	1	1	1
Distribution Minor Maintenance	334	334	334	334	334	334	334	334	334	334
Zone Sub Minor Maintenance	382	382	382	382	382	392	392	392	392	392
	1,397	**1,399**	**1,413**	**1,415**	**1,429**	**1,441**	**1,444**	**1,446**	**1,449**	**1,451**

OPEX: Service Interruptions and Emergencies	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Sub Transmission Line Faults	91	91	91	91	91	91	91	91	91	91
Zone Sub Faults	96	96	96	96	96	106	106	106	106	106
Distribution Faults	797	797	797	797	797	827	827	827	827	827
	984	**984**	**984**	**984**	**984**	**1,023**	**1,023**	**1,023**	**1,023**	**1,023**

Operational Expenditure Total	3,957	3,960	3,973	4,470	3,989	4,041	4,097	4,046	4,048	4,051
System Operations and Network Support	809	831	941	941	941	941	941	941	941	941
Business Support	1,388	1,392	1,391	1,391	1,391	1,391	1,391	1,391	1,391	1,391
AMP Total Operational Expenditure	**6,155**	**6,182**	**6,305**	**6,803**	**6,321**	**6,373**	**6,430**	**6,378**	**6,381**	**6,383**

6. Risk Management

For the purposes of this document risk is defined as any potential but uncertain occurrence that may impact on OJV's ability to achieve its objectives, and ultimately on the value of its business. OJV is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. This section examines OJV's risk exposures, describes what it has done and will do about these exposures and what it will do to reinstate service levels should disaster strike.

6.1. Risk Strategy and Policy

OJV embraces risk management as a critical business task with a key corporate strategy being to "Understand and Effectively Manage Appreciable Business Risk" while each of OJV's asset management strategies also, directly or indirectly, incorporate risk management (refer section 1.5).

PowerNet has developed a risk management framework which is required by PowerNet's risk management policy and requires the framework to be consistent with the ISO 31000:2009 Standard: Risk Management - Principles and Guidelines. The framework aims to formalise the practices that are and have been used to effectively manage the risks that OJV's business faces. This will ensure greater consistency in the quantification of various risks and correct prioritisation of their mitigation as well as ensuring the regularity of review.

6.2. Risk Management Methods

PowerNet's risk management methods are used to manage OJV's risk to acceptable levels with decision making around OJV's asset management related risks guided by the following principles:

- Safety of the public and staff is paramount
- Essential services are the second priority
- Large impact work takes priority over smaller impact work
- Switching to restore supplies prior to repair work
- Plans will generally only handle one major event at a time

6.2.1. Risk Identification

To mitigate risks they must first be identified. While many risks may be obvious, identifying others requires experience and insight into the many factors that could have an appreciable impact on business objectives. The following risk categories have been created as a prompt for ensuring the various risk types are considered during risk identification and so that responsibility for review can be allocated to the applicable manager:

- Procurement
- Health & Safety
- Network, Management, Field Operations and Environment
- Stakeholders, Community and Customers
- Strategic Commercial and Other
- Human Resources

- Finance
- Business Systems, Business Integrity and Technology
- Compliance
- Infrastructure, Plant and Vehicles
- Business Continuity

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

Risk is reviewed when there is a change in perception of the risks that OJV faces; for example after adverse events affecting networks within New Zealand, after events elsewhere in the world catastrophic enough to have been reported locally, or when there is a change in regulations which may require risk to be considered in greater detail.

6.2.2. Risk Quantification

Once a risk has been identified it must be quantified. This is done by determining the following two factors:

- Consequence severity associated with the risk that may eventuate
- Probability the consequences will be encountered

These factors are categorised using relative terms as set out in Table 42 and Table 43 to allow an intuitive assessment of consequence and probability. At the same time this categorisation allows for the use of more robust calculations for these factors where this is practical (especially regarding probability).

Table 42: Event Consequence Categorisation

Consequence:	Very Low	Low	Moderate	High
Safety	First Aid injuries only.	Individual serious injury or recurring minor injuries or health issues.	Fatality(ies) &/or multiple serious injuries for any reason due to PowerNet operations.	Fatality(ies) &/or multiple serious injuries due to criminal negligence.
Performance	Insignificant budget or time over run(s) on work activity.	Budget and time over runs on a significant work activity.	Inability to achieve agreed works within budget and time over 12 month period.	Consistent inability to achieve agreed works within budget and time over several years.
Network Reliability	Marginal breach(es) of a reliability KPI due to matters under PowerNet's control.	Significant breaches of an important reliability KPIs due to matters under PowerNet's control.	Repeat breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).	Repeat long term breaches of reliability KPIs due to matters under PowerNet's control (or perceived by stakeholders to be under PowerNet's control).

Consequence:	Very Low	Low	Moderate	High
Network Disruption	Network disruption up to 6 hours.	Disruptions - up to 2 days - of a major network.	Repeat disruptions - up to 2 days per event of a major network.	Extended (10 days +) disruption of a major network.
Reputation	Local press attention - short-term impact on public memory.	Local press attention (not front page) and/or regulator inquiry.	Local TV news and/or regulator investigation - medium-term impact on public memory.	International TV news headlines and/or government investigation - long-term impact on public memory.
Financial	Loss of assets/revenue or unbudgeted costs less than: < 1% p.a.	Loss of assets/revenue or unbudgeted costs less than: 1-5% p.a.	Loss of assets/revenue or unbudgeted costs less than: 5-10% p.a.	Loss of assets/revenue or unbudgeted costs less than: >10% p.a.
Governance	Shareholder awareness.	Perception of systemic underperformance, shareholder concern.	Shareholder dissatisfaction.	Dysfunctional governance - major conflicting interests or fundamental change in governing board direction.
Compliance	Prosecution / improvement notice.	Prosecution of business / prohibition notice.	Prosecution of Director or other employees.	Breach resulting in Imprisonment of Directors or other employees, or appointment of statutory board to a network due to matters under PowerNet control.
Environmental	Transient environmental harm.	Significant release of pollutants with mid-term recovery.	Significant long term environmental harm.	Catastrophic, long term environmental harm.

Table 43: Event Probability Categorisation

Probability Ranking	Descriptor	Expected Occurrence Interval
4	Highly Likely	Greater than once per year
3	Possible	Once every 1-10 years
2	Unlikely	Once every 10-100 years
1	Very Unlikely	Less than 100 years

6.2.3. Risk Ranking

Together consequence and probability give an overall measure of a risk. Table 44, commonly known as a risk matrix, shows how these factors are combined to give a relative risk level so that risks can be ranked. 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.

Table 44: Risk Ranking Matrix

Consequence:	Very Low	Low	Moderate	High
Highly Likely	Level 3	Level 5	Level 6	Level 7
Possible	Level 3	Level 4	Level 5	Level 6
Unlikely	Level 2	Level 3	Level 4	Level 6
Very Unlikely	Level 1	Level 2	Level 3	Level 5

6.2.4. Risk Treatment and Mitigation Prioritisation

With finite resources risk can never be completely 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 a number of options are available for the treatment of any risk with each treatment option likely to come at various levels of cost, effort and time to implement. At the same time each treatment option may be more or less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 45 summarises the types of treatment options that should be considered for any risk, ordered by effectiveness for the control of risk.

Table 45: Options for Treatment of Risk

Treatment Options	
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 Termination is considered 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.

In some situations the most appropriate treatment option will be obvious; however deciding between high cost effective treatments and low cost but less effective treatments can be difficult. The desired outcome is to choose the least "cost" option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe; this requires careful judgement of all the factors involved.

Good risk management recognises that available resource is limited, meaning that risks cannot be effectively mitigated immediately. Therefore effective risk management also requires prioritisation of the many risk reduction actions identified and to do this the "greatest risk reduction for the resource available" is used as a guiding principle. Appropriate resourcing also needs to be considered as adjustments to the available resource may be necessary to control risk appropriately. This is explicitly recognised as part of the new Health and Safety at Work Act where sufficient resource to reduce hazards "as far as reasonably practicable" must be provided.

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. Again the level of risk will determine if standards are retrospective i.e. applied to existing network rather than only applying to new assets installed.

6.3. OJV's Asset Management Risk

Asset management related risks that have been identified for OJV have been classified under the categories; physical, safety and environmental, human, external, weather, and corporate; with a summary of the risk assessment under each of these categories is as follows.

6.3.1. Physical

The following physical risks have been identified with Table 46 and Table 47 summarising their quantification and treatment responses:

- Earthquake – no recent history of major damage, although recent earthquakes in Christchurch have proven that large and unexpected events may occur and can have significant impact on a network.
- Tsunami – maybe triggered by large off shore earthquake. OJV has several low-lying coastal substations that are potentially vulnerable to tsunami, although most of these are nearing end of life which enables them to be targeted for relocation.
- Liquefaction – post Christchurch's 22 February 2011 6.3 magnitude earthquake, the hazard of liquefaction has become a risk to be considered.
- Fire – transformers are insulated with mineral oil that is flammable and buildings have flammable materials so fire will affect the supply of electricity. Source of fire could be internal or from external sources.
- Asset Failures – equipment failures can interrupt supply or negate systems from operating correctly. i.e. failure of a padlock could allow public access to restricted areas.

Table 46: Risk Associated with Physical Events and Responses

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 relocate or reinforce as necessary.
Liquefaction	Very Unlikely	Low to Medium	• Specify buildings and equipment foundations to minimise impact.
Fire	Very Unlikely	High	• Supply customers from neighbouring substations where practical. • Maintain fire alarms in buildings.

Table 47: Risk Associated with Equipment Failures and Responses

Event	Likelihood	Consequence	Responses
33kV & 66kV Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by ringed subtransmission or through the distribution network. • All new works 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.
11kV Switchboard	Unlikely	Medium	• Annual testing including PD[7] and IR[8]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard with use of mobile regulators.
11kV & 400V Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network where practical.
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 two 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.

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

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

As the impact of equipment failure is variable, a central control room is provided, which is manned 24 hours a day by PowerNet staff. Engineering staff are on standby at any time to provide backup assistance for network issues. Faults contractors provide onsite action and minor failure repairs with contractors 'on-call' for medium to large failures or storms.

6.3.2. Safety & Environmental

Table 48 summarises the safety and environmental risks that have been identified, along with their quantification and treatment responses:

- 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, that is capable of causing electric shock
- Arc flash – potential for significant injury to staff from a fault on or near equipment they are using/working on
- Oil spills from transformers or oil circuit breakers
- Staff error causing worksite safety risk
- Historical assets not meeting modern safety requirements
- Site security: unauthorised persons approaching live components through unlocked gate etc.

Table 48: Risk Associated with Safety and Environmental Events and Responses

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

Event	Likelihood	Consequence	Responses
			• 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, depending on check of specifications and evaluation of risk
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Standardised exit procedures in 3rd party building • Sub clearances to AS2067 s5 • Design to avoid climbing aids etc.

6.3.3. Human

The following human related risks have been identified with Table 49 summarising their quantification and treatment responses:

- Pandemic – impact depends on the virility of the disease. Could impact on staff work as they try to avoid infection or become unable to work.
- Terrorism/Vandalism – range varies from malicious damage to copper theft to 'tagging' of buildings or equipment. Cyber-attack could also occur; considered low risk at present but vulnerability increases as the network becomes "smarter".

Table 49: Human Event Risks and Responses

Event	Likelihood	Consequence	Responses
Pandemic	Unlikely	Low to High	• Work to the PowerNet pandemic plan. • Includes details such as working from home, only critical faults work and provide emergency kits for offices etc.

Event	Likelihood	Consequence	Responses
Vandalism	Possible	Low to High	• Six monthly checks of all ground-mounted equipment. • Faults contractor to report all vandalism and repair depending on safety then economics. i.e. tagging/graffiti would depend on the location and content. • Any safety problems will be made safe as soon as they are discovered.
Terrorism	Very Unlikely	High	• Ensure security of restricted sites. • Use alternative routes and equipment to restore supply, similar to equipment failures above.
Cyber Attack	Very Unlikely	High	• Secure communications links • Analyse and remove vulnerabilities • Review and apply industry best practice

6.3.4. External Factors

The following external factor risks have been identified with Table 50 summarising their quantification and treatment responses:

- Animals either physically bridging overhead conductors – e.g. birds, possums – or causing 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 50: External Factors

Event	Likelihood	Consequence	Responses
Animal	Highly Likely	Low	• Possum guards • 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.

6.3.5. Weather

The following weather related risks have been identified with Table 51 summarising their quantification and treatment responses:

- 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 – can cause damage to poles or ground-mount equipment

Table 51: Risk Associated with Weather Events and Responses

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. • Impact can be reduced by undergrounding of lines.
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. • Impact can be reduced by undergrounding of lines.
Flood	Unlikely	Low	• 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. • Impact can be reduced by undergrounding of lines.

6.3.6. Corporate

The following corporate risks have been identified with Table 52 summarising their quantification and treatment responses:

- 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 52: Corporate Risks and Responses

Event	Likelihood	Consequence	Responses
Investment	Unlikely	Low	• New larger contracts require Shareholder Guarantee before supply is provided.
Loss of Revenue	Very Unlikely	High	• Continue to have Use of System Agreements with retailers. • New large investments for individual customers to have a guarantee.
Management Contract	Very Unlikely	High	• Continue management contract with PowerNet noting that it operates a Business Continuity Plan

Event	Likelihood	Consequence	Responses
Regulatory	Very Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Resource	Unlikely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff.

6.4. Emergency Response and Contingency

The following tactics have been or are being implemented to manage risk for OJV (especially for high-impact low-probability 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

Additionally OJV has specific contingencies in place through its management company PowerNet, as listed in sections 6.4.1 to 6.4.5.

6.4.1. 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/limit exposure to potential liability claims filed against Company/Directors/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.

6.4.2. 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:

1. 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.
2. 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.

6.4.3. 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, for example OJV will borrow a transformer from TPCL to accommodate the Puketoi area summer load if delivery of the new Patearoa transformer is delayed.

6.4.4. 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.

6.4.5. Insurance

OJV holds the following insurances:

- Material damage and business interruption over Substations and Buildings.
- Contracts works.
- Directors and officers liability.
- Utilities Industry Liability Programme (UILP) that covers Public, Forest & Rural Fires and Products liability.
- Statutory liability.
- Employee and fidelity/crime.

Contractors working on the network hold their own liability insurance.

7. Evaluation of Performance

7.1. Progress against Plan

Progress against plan is presented for the 2014/15 disclosure year, which preceded the incorporation of ESL into OJV for regulatory reporting. Midway through the year TPCL and EIL bought out the Marlborough Lines Limited (MLL) stake in OJV, and assigned PowerNet to replace MLL as the provider of engineering management services. The change in focus resulting from this transfer of responsibility impacted on OJV's progress against some of the budgets set by MLL in the 2014-24 AMP.

7.1.1. Capital Expenditure

Table 53: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2014/15 ($k)	Actual 2014/15 ($k)	Variance
Consumer Connection	1,000	2,838	+184%
System Growth	1,779	2,063	+16.0%
Asset Replacement and Renewal	4,520	5,890	+30.3%
Asset Relocations	1,405	152	-89.2%
Quality of Supply	600	-	-100%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	2,090	2,192	+4.9%
Capital Expenditure on Network Assets	**11,394**	**13,135**	**+15.3%**

Capital works varied from budget due to:

- Customer Connections – 184% higher than budget mainly due to increased irrigation demands and other growth and development that can vary substantially from year to year.
- System Growth – 16% over budget as a result of the network reinforcement required in various areas with the number of new connections.
- Asset Replacement and Renewal – 30% overspent due to increased safety awareness and advanced programme of pole replacement and line height improvements.
- Asset Relocations – 89% underspent due to delays by local Council led projects to underground the main streets in Balclutha and Milton.
- Quality of Supply – underspent due to delays associated with equipment supply and land owner approvals for recloser installations
- Other Reliability, Safety and Environment – within 5% of budget.

7.1.2. Operational Expenditure

Table 54: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2014/15 ($k)	Actual 2014/15 ($k)	Variance
Asset Replacement and Renewal	616	105	-83.0%
Vegetation Management	850	1,192	+40.2%
Routine and Corrective Maintenance and Inspection	1,094	880	-19.6%
Service Interruptions and Emergencies	1,658	1,209	-27.1%
Operational Expenditure on Network Assets	**4,218**	**3,386**	**-19.7%**

Maintenance varied from budget due to:

- Asset Replacement and Renewal – 83% below budget due to some line and pole replacement work being so material to the overall assets that it was categorised as CAPEX.
- Vegetation Management – 40% overspent as an ongoing emphasis on reliability and fault reduction has driven increased vegetation control.
- Routine and Corrective Maintenance and Inspection – 19.6% below budget due to PowerNet scaling back the substantial accelerated inspection programme set under Marlborough Lines management.
- Service Interruptions and Emergencies – 27% below budget due to reduced minor maintenance as resource was diverted to capital work.

7.2. Service Level Performance

7.2.1. Customer Consultation

A face to face survey using a survey company was undertaken with seven key clients. It was found businesses generally had a very positive view of OtagoNet as a professional company and were generally happy with the current level of reliability. Customers appreciate the notification of planned outages and the ability to negotiate timing to minimise impacts on their businesses. While most customers seemed happy with the restoration times after unplanned outages, there was a wide range of preferred timeframes indicated from one day to fifteen minutes. On the whole communication with OtagoNet regarding network issues or progress restoring supply during unexpected interruptions was seen positively however a couple of comments were received that this communication could have been more timely or more helpful and informative.

OtagoNet is generally perceived to have the needs and best interests of its customers at heart although there was one complaint from a customer who felt he had to wait too long for a disconnection. Some businesses expressed a desire for more proactive and regularly initiated contact from OtagoNet staff to make them more aware of pricing and reliability options, while others appreciated the fact that OtagoNet had made a personal visit rather than simply dealing with their enquiries over the phone.

7.2.2. Reliability

Table 55 displays the target versus actual reliability performance on the network. The 2014/15 year performance was acceptable given the higher than usual number of storms in the year (with boundary values exceeded on six separate occasions). However an irregularity in the 2012 Default Price-Quality Path Determination forced OJV to report 2014/15 SAIDI and SAIFI in a manner inconsistent with previous years or with the preceding and succeeding Determinations, thus creating a technical but not actual breach in SAIFI.

Table 55: Performance against Primary Service Targets

	2014/15 AMP Target	2014/15 Actual
SAIFI	2.7	3.27
SAIDI	323	353.2

7.2.3. Customer Satisfaction

Results for 2014/15 are shown in Table 56:

Table 56: Performance against Secondary Service Targets

Attribute	Measure	Target 2014/15	Actual 2014/15
Customer Satisfaction on Faults	Power restored in a reasonable amount of time {CES: Q6(b)}	>70%	89%
	Information supplied was satisfactory {CES: Q10(b)}	>60%	83%
	OtagoNet first choice to contact for faults {CES: Q10}	>35%	25%[9]
Voltage Complaints	Number of customers who have made voltage complaints {IK}	-[10]	4
	Number of customers having justified voltage quality complaints {IK}	<15	2
Planned Outages	Provide sufficient information {CES: Q5(a)}	>75%	100%
	Satisfaction regarding amount of notice {CES: Q5(c)}	>75%	96%
	Acceptance of max of one planned outage every year {CES: Q3}	>50%	99%
	Acceptance of planned outages lasting four hrs on average {CES: Q4}	>50%	94%

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

The 2014 AMP set targets for Customer Satisfaction Surveys (questionnaires sent to customers with invoices for new connections), however the use of these surveys has been discontinued due to an extremely poor response rate. OJV is investigating alternative methods of gathering this information, including the possibility of adding similar questions to the existing Customer Engagement Survey (phone survey carried out by an independent consultant).

All service levels were comfortably above targets with the exception of OtagoNet's being the first choice to contact for faults. This metric shows a pleasing increase from the last two full AMPs (4% in

[9] "PowerNet" is also accepted as a correct response to this question. 1% of customers specified PowerNet in 2014/15.

[10] This target was not set for 2014/15 as the AMP for that year was compiled under Marlborough Lines direction.

2013 and 13% in 2014) and shows that branding initiatives such as newsletter campaigns have had a positive effect. The majority of the customers who did not rate OtagoNet as their first choice would either call their retailer (34%), or wouldn't call anyone (21%).

7.2.4. Network Efficiency

Table 57: Performance against Efficiency Targets

Measure	2014/15 Target	2014/15 Actual	Comment
Load factor	-	79%	No target set as 2014/24 AMP was written under Marlborough Lines direction. Load control continues to be used during LSI peaks
Loss ratio	< 5.0%	4.2%	Variable - dependant on Retailer accruals
Capacity utilisation	> 30%	28.2%	Influenced by load factor

The growth seen at the GXP level has been distorted with Transpower's introduction of the TPM[11] where individual EDB peaks have been replaced by a regional grouping. This has allowed OJV to relax load control during the year but has had a negative impact on load factor.

Losses tend to vary from year to year more than would be expected due to 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.

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 some customers means there is a practical and economic limit to how much this factor can be improved. OJV's capacity utilisation compares well with other predominantly rural distribution businesses.

7.2.5. Financial Efficiency

Table 58: Performance against Financial Targets

Measure	2014/15 Target	2014/15 Actual
Direct Cost/km	$960	$649.96
Indirect Cost per Customer	$240	$106.73

Direct Cost/km and Indirect Costs per Customer were both within targets.

[11] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island region. See http://www.electricitycommission.govt.nz/rulesandregs/rules Part F, Section IV for more details.

7.3. Asset Management Maturity Assessment Tool (AMMAT) Performance

The AMMAT is based on a selection of the questions from the internationally recognised asset management standard PAS-55, that are intended to prompt consideration of performance against a number of facets of asset management practice. Each question can be scored from '0' to '4' with word pictures describing each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

OJV understands the foundations of good asset management practice and aims to implement each aspect of the AMMAT, however often implementation is not systematic and therefore may not always be consistent or applied to all potential areas of benefit. This effect has led OJV to score itself as a "2" for many AMMAT questions with a total range from 1 to 3, as shown in Figure 41.

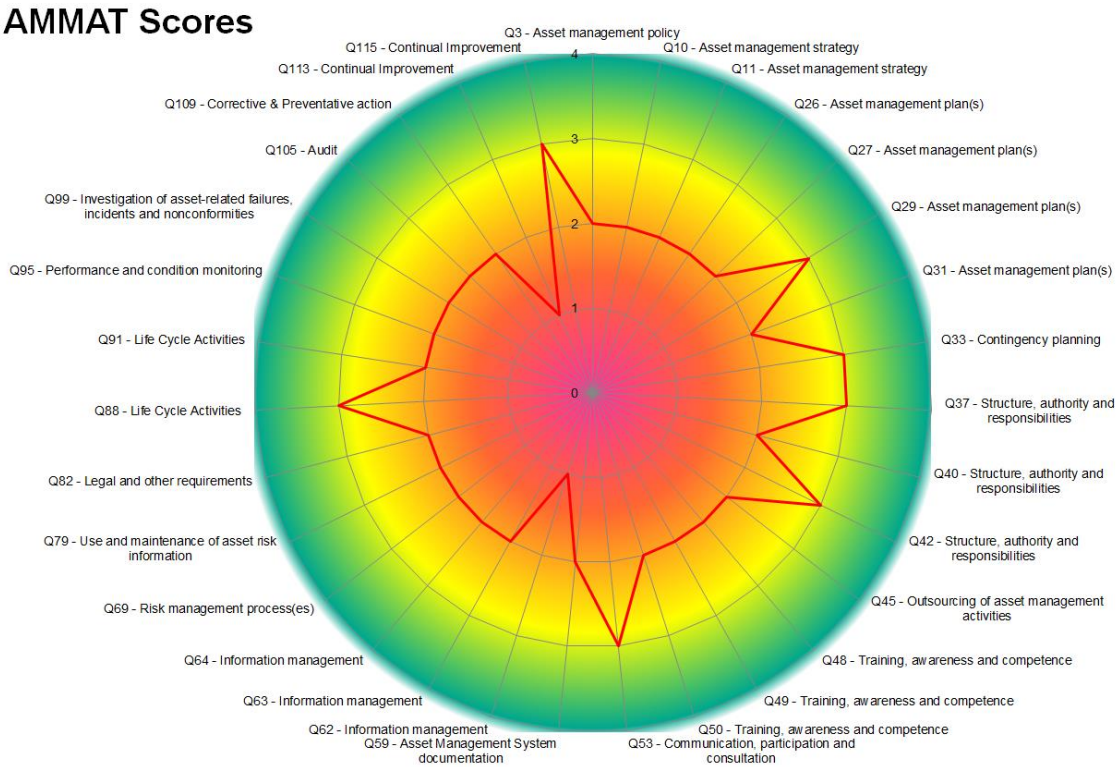

Figure 41: OJV's AMMAT Results

7.4. Gap Analysis and Planned Improvements

7.4.1. Maintenance and Capital Works

Improvement of short and long term project and maintenance planning processes should lead to better scheduling of resources and improved budget estimations.

The amalgamation of OJV's network management company PowerNet and contracting company Otago Power Services Limited should allow the realisation of more efficient work practices. The amalgamated company PowerNet has also employed additional staff to extend its project management capacity. This should help increase productivity and make OJV better placed to deliver planned projects.

7.4.2. Reliability

Reliability has been heavily influenced by adverse weather in recent years and is trending close to the applicable limits. The quality limits that have applied to OJV's network have been problematic in that OJV has not been permitted to include the outage history of assets acquired from Transpower in 2013/14 (which supply over 20% of OJV's customers) in its reliability limits.

From April 2015 the new normalisation boundaries calculated under the Default Price-Quality Path Determination will include the outage history of the Transpower assets; however it will also include the effect of OJV's relatively good reliability performance over 2010-2013 which reduces the "headroom" OJV has available for extreme weather events.

OJV will look to control the impact of events that might incur large customer-minute totals by increasing the number of remotely controlled devices on the network to speed isolation of faulty sections and restoration of supply to healthy sections. Over the longer term OJV will complete the conversion of the Palmerston area subtransmission network to a closed ring, which will minimise the number of (usually very high impact) outages on that part of the network.

OJV's network management company PowerNet will work to retain experienced field services staff and maintain long term relationships with external contractors so quality personnel with sufficient network familiarity are available for efficient restoration of supply.

Regular network inspections will be continued and critical items will be acted on as they are identified. Also data capture and condition assessment will be increased above reactive maintenance practices to increase knowledge of the assets and their condition to enable better planning based on more accurate and comprehensive asset data.

7.4.3. AMMAT

For a distribution company of OJV's size a score of "2" for many of the asset management functions is considered appropriate. However as PowerNet provides asset management services for OJV together with other networks, OJV believes that some improvements are realisable and appropriate. OJV's long-term target is therefore to achieve an average AMMAT score of 3 across all categories. OJV is working towards closing the gaps, however it is recognised that there is often a substantial amount of work involved in incrementing an AMMAT score. While there have been no changes in score since the previous AMP, the following work has been undertaken:

- This latest version of OJV's AMP (Q26-31) has been largely rewritten to better comply with the Electricity Distribution Information Disclosure Determination 2012. Improvements have also been made to further embed the AMP in OJV's internal asset management planning and to support continuous improvement (Q69) especially in the area of communication.
- The overhead lines inspection process has been an area of recent focus for OJV. Objective criteria have been set out in an inspection standard (Q95), for inspectors to use when determining how quickly a defect must be rectified to minimise the chances of failure. A mobile application is being developed that will allow inspectors to record the results of their inspections in a structured format (Q62). This format is designed to allow comprehensive

bulk analysis of inspection data to promote continuous improvement (Q113) of the inherent trade-off between repair cost and asset performance in the inspection standard.

- Responsibility for investigation of asset-related failures (Q99) has been codified in the PowerNet standard PNM-067; this standard also prescribes defect elimination measures (Q113) where a systemic defect is found. PowerNet has joined the National Equipment Defect Reporting System (NEDeRS) scheme (Q115); standard PNM-066 sets out the process for promulgating details of identified systemic defects via NEDeRS where appropriate.
- OJV has adopted the Incident Cause Analysis Methodology (ICAM) approach to investigating incidents (Q113). A roster of trained staff (Q50) is rotated through for the investigation of eligible incidents (Q99) with the ICAM to be given priority over routine work.
- OJV is initiating a Safety by Design system and has developed an interim policy and procedure to ensure a systematic process for identifying and effectively managing risks (Q69) associated with each lifecycle stage of any new assets designed. Future work will aim to extend this systematic risk management approach across its existing assets to ensure regular comprehensive reviews are undertaken.
- A programme of Lean Management implementation has been initiated. This is a long-term approach to business processes that systematically seeks to achieve small, incremental changes in processes in order to improve efficiency through the elimination of wastage. Lean management is an approach to running an organization that supports the concept of continuous improvement (Q113).
- Improvements to OJV's Asset Management System (AMS) are being implemented including:
    - Work Scheduling to more systematically and efficiently schedule and track asset maintenance activities.
    - 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.
    - Electronic purchase orders are also being implemented to support these improvements.

OJV recognises this organisation of information (Q62) as important for managing its assets efficiently and effectively by improving ability to estimate costs for future similar work and evaluating whole lifecycle costs.

8. Capability to Deliver

OJV succeeds in delivering when the network development and maintenance plans are achieved on time and to budget while achieving service level targets from the present time to the long term. To achieve successful delivery OJV must have sufficient staffing (planning, management, field services) and financial resources available along with having appropriate systems and processes in place.

8.1. Systems and Processes

The core of OJV's asset management activities lie with 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 hierarchy of data model shown in Figure 42 describes the typical sorts of information residing within OJV's business (including in PowerNet employees' brains).

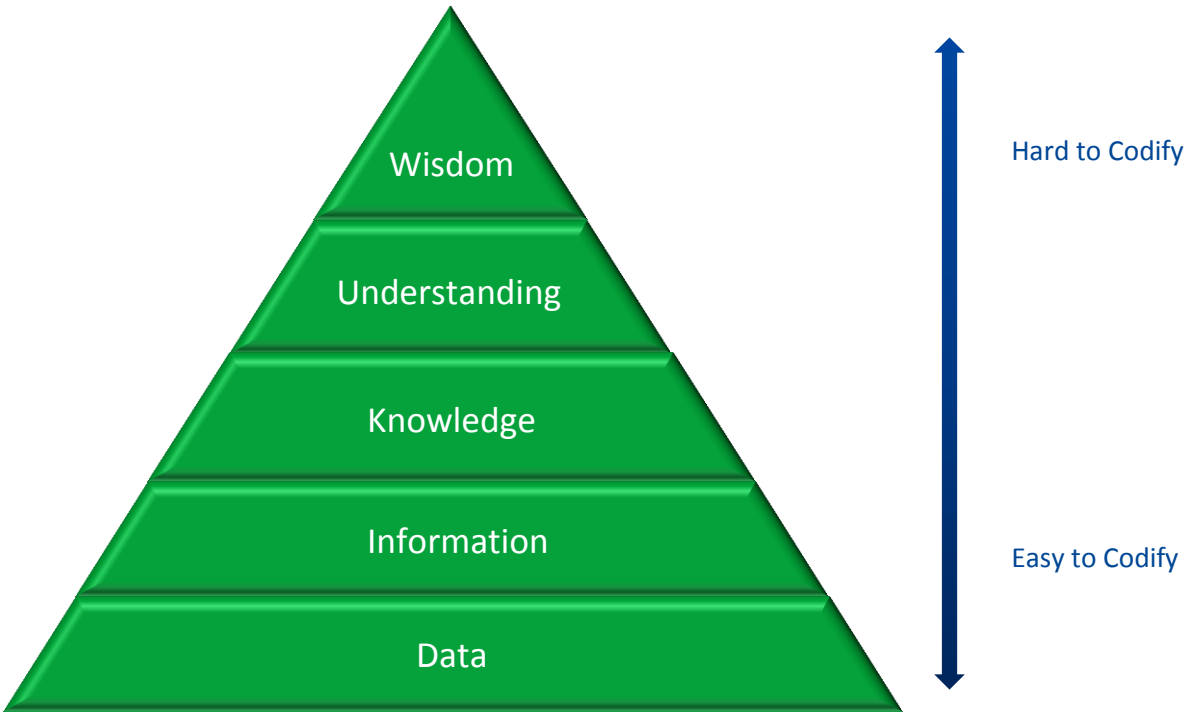

Figure 42: Hierarchy of Data

- The bottom two layers 'Data' and 'Information' of the hierarchy tend to relate strongly to OJV's asset and operational data and the summaries of this data that form one part of OJV's decision making.
- The middle layer 'Knowledge' tends to be more broad and general in nature and may include such things as technical standards that codify accumulated knowledge into a single useful document.
- The top two layers 'Understanding' and 'Wisdom' tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside. As indicated in Figure 42 it is generally hard to codify these things, hence correct application is heavily dependent on skilled and experienced people.

8.1.1. Asset Management Systems

OJV has a variety of information management tools which capture asset data and can be used to aggregate this data into summary information. From this information OJV has a great deal of knowledge about almost all of the assets; their location, what they are made of, generally how old they are and how well they can perform. This knowledge will be used for either making decisions within OJV's own business or assisting external entities to make decisions.

The decision making process involves the top two levels of the hierarchy, understanding and wisdom, which tend to be broad and enduring in nature. Although true understanding and wisdom are difficult to codify, it is possible to capture discrete pieces of understanding and wisdom and then codify them into such documents as technical standards, policies, processes, operating instructions, spreadsheet models etc. Such "knowledge-level" data generally represents the upper limit of what can be reasonably codified.

Accurate decision making therefore 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 suboptimal outcomes. The roles and interaction of each component of the hierarchy are incorporated in Figure 43 which provides a high level summary of OJV's asset management processes and systems.

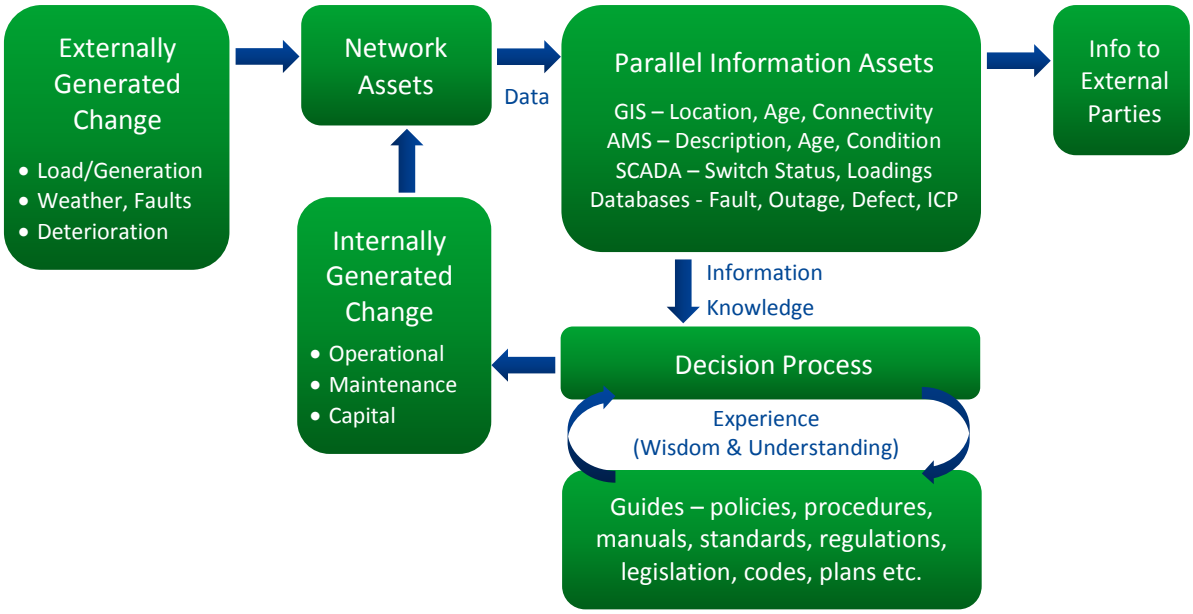

Figure 43: Key information systems and processes

8.1.2. Processes and Documentation

OJV's key processes and systems are based around the lifecycle activities defined in Figure 43, which are based around the AS/NZS9001 Quality Management System. The processes are not intended to be bureaucratic or burdensome, but are rather intended to guide OJV's decisions toward ways that have proved successful in the past (apart from safety related procedures which do contain mandatory instructions). Accordingly these processes are open to modification or amendment if a better way becomes apparent.

The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 4:

- 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.

8.1.3. Documents and Control Reviews

Each document is controlled by an owner at management level who is given responsibility for the document's review and update. The documents are reviewed periodically (which includes review of the underlying processes that have been documented) to ensure they are kept up to date and incorporate any changes that have been identified as necessary. 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; all staff are notified by email, and where considered necessary, by placement on noticeboards and direct training/communication to individuals effected.

8.1.4. Asset Management Tools

PowerNet maintain and utilise a number of software based tools to efficiently and effectively manage data and knowledge for OJV's network assets.

The **Asset Management System (AMS)** stores OJV's assets descriptions, details, ages 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 AMS. Maintenance regimes, field inspections and customers produce tasks and/or estimates that are sometimes grouped, and a work order is issued from the AMS 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 AMS in conjunction with other more traditional techniques such as drawings and individual test reports. The Maximo software package is utilised as OJV's AMS.

An Intergraph based **Geographic Information System (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.

Export of data from the GIS into **Load Flow and Fault Analysis Software** 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.

The **Supervisory Control and Data Acquisition (SCADA)** system provides real time operational data such as loadings, voltages, temperatures 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.

Monthly reports out of the **Finance One (F1)** financial system 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 AMS system. Interfaces between F1 and the AMS track estimates and costs against assets.

The **Outage, Faults and Defect Databases** 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 efficient and 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 Governing Committee for monitoring, together with details of planned outages.
- Asset defects are captured in another database for technical asset issues which don't have an immediate impact on service levels but potentially could, if not responded to. Defects are tracked in this database and scheduled for remediation.

The **Condition Assessment 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 Condition Assessment 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.

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history resides in an **ICP/Customer database** system developed by ACE Computers. 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.

8.1.5. Data Control, Improvement and Limitations

OJV's original data capture emphasised asset location and configuration and was used to populate the GIS, but didn't include a high level of asset condition. 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 apply an age but many poles had no supporting information. Due to old poles not having a manufacture date affixed, it is very difficult to obtain the actual age to update GIS. Options have been considered to get ages measured for the un-dated poles but no economic methodology has been found, and condition data is considered to be more useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry. For all other information – 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 more timely as-builts with PowerNet staff taking GPS[12] coordinates for poles and use of scan-able forms for data input (Teleform system).

Data for the AMS 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 percent of the network (by length) is condition assessed each year to update asset condition data (noting that asset condition is continually varying), and any variances are corrected.

As the AMS system has recently been replaced the opportunity was taken during transfer of data to the new system to check for accuracy and completeness with some data improvements achieved through update where issues were found. Further improvements to the AMS 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.

[12] GPS = Global Positioning System, a device that uses satellites and accurate clocks, to measure the location of a point.

Assets are assigned a unique reference common to both the GIS and AMS. 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 be 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.

Table 59 provides a summary for the completeness of OJV's data.

Table 59: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Mostly Good	Some delays between job completion & GIS update, some LV poles not yet captured
GIS	Location	Okay	Some delays between job completion & GIS update Significant errors in location for some poles – a location process is being carried out in tandem with inspections
GIS	Age	Poor	Pole ages not available for many
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Okay	Some delays between job completion & Maximo Update
AMS	Details	Okay	Some delays between job completion & Maximo Update
AMS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

8.2. Funding the Business

OJV's business is funded from the revenue received from their customers. And through a wide range of internal processes, policies and plans, the company converts that funding into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and supply quality that customers want. This business model is shown in Figure 44.

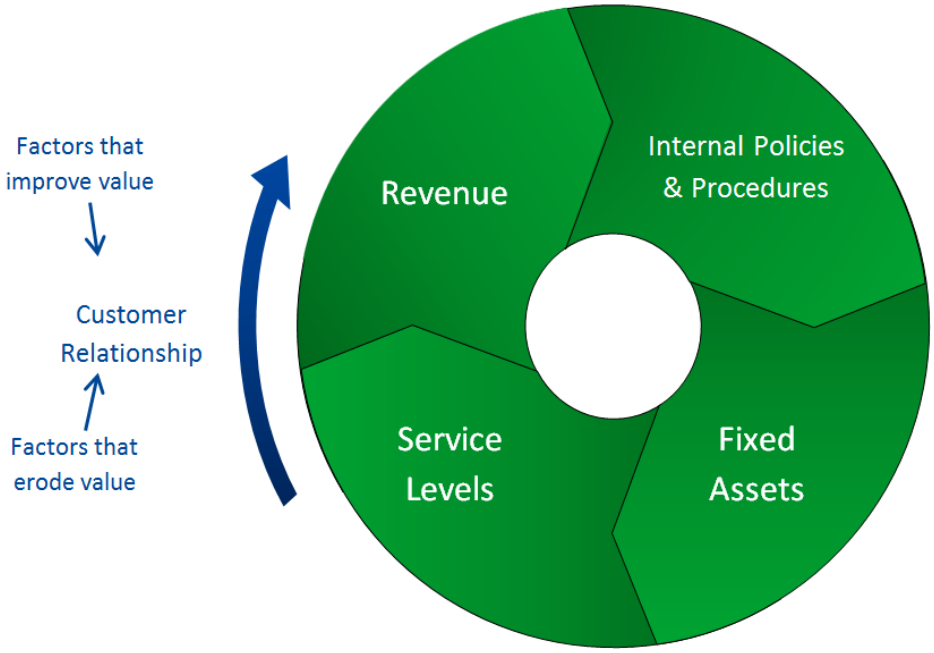

Figure 44: Customer Interface Model

8.2.1. Revenue

OJV's money comes primarily from the 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 closely tied to the value of assets as set out in a "price path" determined by the Commerce Commission.

In regard to funding new assets (i.e. beyond the immediate financial year) OJV has considered the following approaches:

- 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

8.2.2. Expenditure

Work is done to maintain the asset value of the network and to expand or augment to meet customer demands.

8.2.3. Influences on the Value of Assets

An annual independent telephone 'Customer Engagement Survey' is undertaken in September 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 60 below:

Table 60: 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.

8.2.4. Depreciating the Assets

The accounting treatment of using straight-line depreciation doesn't strictly model the decline in service potential of an asset. It may well quite accurately model the underlying physical processes of rust, rot, acidification, erosion etc., but an asset often tends 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 worn out assets. This will be particularly important as the "bow wave" of asset renewals approaches.

8.3. Staff and Contracting Resources

The greatest issue presently facing OJV is staff and contracting resources. Each item or project making up the AWP is carefully considered as to the man hours required using the experience gained over many years of network management. The Works Programme as a whole is then considered to ensure that it is realistic with the resources expected to be available and any adjustments can be made. Low priority work may be delayed short term where a commitment to increase staff or contractor numbers has been made such that the necessary works plan will not fall behind. It is important that the AWP "smooths" the year to year work volumes required (to the extent possible acknowledging appropriate risk controls) to provide a relatively constant work stream.

The internalising of PowerNet's field services in the OJV area will be of great benefit in ensuring a longer term approach may be taken to resourcing. This means staff numbers can be increased with added confidence that they will be fully utilised in future years given the long term plans developed. Working closely with OJV's contractors is also an important part of the AWP development process, carefully communicating the detailed works plan and getting commitment that sufficient resources will be available for the year ahead. The future Works Programme is also communicated so that contractors can confidently commit to hiring extra staff where appropriate, recognising OJV's on-going development and maintenance requirements.

Appendix 1 – Directors Approval

We, Douglas William Fraser and Neil Douglas Boniface 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 following attached information of OtagoNet Joint Venture prepared for the purposes of clause 2.4.1, clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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 and 12c are based on objective and reasonable assumptions which both align with OtagoNet Joint Venture's corporate vision and strategy and are documented in retained records.

D W Fraser

N D Boniface

Date: 30 March 2016

Appendix 2 – Customer Engagement Questionnaire

OtagoNet Customer Engagement Report © Gary Nicol associates

Phone	Date	Interviewer

Good afternoon/evening my name is _____. I am conducting a brief customer survey on behalf of OtagoNet.

May I please speak to a person in your home who is responsible for paying the electricity account?

(Reintroduce if necessary) May I trouble you for a few minutes of your time?

Question 1: Do you know who OtagoNet is?	Yes	**1**	
	No	**2**	Go to Q 1(c)

Question 1(a): Where did you most recently hear about OtagoNet? (Prompt)	Newsletter	**1**	
	Billboard	**2**	
	Sponsorship	**3**	**1**
	Other	**4**	
	Don't know/unsure	**5**	

Question 1(b): Using a 1 to 5 rating scale where 1 is Poor and 5 is Excellent can you rate the performance of OtagoNet over the last 12 months for:	Caring for customers	**1 2 3 4 5**
	Reliable power supply	**1 2 3 4 5**
	Supporting the community	**1 2 3 4 5**
	Safety conscious	**1 2 3 4 5**
	Efficient	**1 2 3 4 5**

Question 1(c): OtagoNet owns the local electricity lines and substations that supply power to your premises.

Question 2: Do you live in a mainly rural or urban area?	Urban	**1**
	Rural	**2**

Question 3: OtagoNet is proposing on average one planned interruption to your power supply every year in order to carry out maintenance or upgrade work. Do you consider this number of planned interruptions to be reasonable?	Yes	**1**	Go to Q 4
	No	**2**	Go to Q 3(a)
	Don't know/unsure	**3**	Go to Q 4

Question 3(a): How many years between planned interruptions do you consider to be more reasonable?	2 years	**1**	
	3 years	**2**	
	4 years	**3**	
Question 4: Such planned interruptions will on average last up to four hours each. Do you consider this amount of time to be reasonable?	Yes	**1**	Go to Q 5
	No	**2**	Go to Q 4(a)
	Don't know/unsure	**3**	Go to Q 5
Question 4(a): What length of time would you consider to be more reasonable? (Specify hours)	1 hour	**1**	
	2 hours	**2**	
	3 hours	**3**	
Question 5: Have you received advice of a planned electricity interruption during the last 6 months?	Yes	**1**	
	No	**2**	Go to Q 5(e)
	Don't know/unsure	**3**	Go to Q 5(e)
Question 5(a): Were you satisfied with the amount of information given to you about this planned interruption?	Yes	**1**	Go to Q 5(c)
	No	**2**	Go to Q 5(b)
	Unable to recall	**3**	Go to Q 5(c)
Question 5(b): What additional information would you have liked?			
Question 5(c): Do you feel that you were given enough notice of this planned interruption?	Yes	**1**	Go to Q 5(e)
	No	**2**	Go to Q 5(d)
	Don't know/unsure	**3**	Go to Q 5(e)

Question 5(d): How much notice of planned interruptions would you prefer to be given? (Specify days/weeks) (Do not prompt)	1 day	**1**	1 week	**4**
	3 days	**2**	2 weeks	**5**
	5 days	**3**	Other	**6**

Question 5(e): Does it matter to you what day or time a planned outage takes place?	Yes	**1**	
	No	**2**	Go to Q 6

Question 5(f): Which would you prefer?	Mornings	**1**	
	Afternoons	**2**	
	Evenings	**3**	
	Other	**4**	
	Weekdays	**1**	
	Weekends	**2**	
	Other	**3**	
	Don't know	**4**	
Question 6: Have you had an unexpected interruption to your power supply during the last 6 months?	Yes	**1**	
	No	**2**	Go to Q 7
	Unable to recall	**3**	Go to Q 7

Question 6(a): How long did it take for your supply to be restored after your most recent interruption? (Specify hours/days) (Do not prompt)	Within 45 min	**1**	3 hours	**5**
	1 hour	**2**	4 hours	**6**
	1½ hours	**3**	12 hours	**7**
	2 hours	**4**	Don't know	**8**
			Other	**9**

Question 6(b): Do you consider your electricity supply was restored within a reasonable amount of time?	Yes	**1**	Go to Q 7
	No	**2**	Go to Q 6(c)
	Unable to recall	**3**	Go to Q 7

Question 6(c): What do you consider would have been a more reasonable amount of time? (Specify hours/days) (Do not prompt) **Go to Q8**	30 minutes	**1**	1½ hours	**4**
	45 minutes	**2**	2 hours	**5**
	1 hour	**3**	Other	**6**

Question 7: In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before electricity supply is restored to your home? (Specify hours/days) (Do not prompt)	5 minutes	**1**	2 hours	**10**
	10 minutes	**2**	3 hours	**11**
	15 minutes	**3**	4 hours	**12**
	20 minutes	**4**	5 hours	**13**
	30 minutes	**5**	6 hours	**14**
	40 minutes	**6**	12 hours	**15**
	45 minutes	**7**	1 day	**16**
	1 hour	**8**	Unsure	**17**
	1½ hours	**9**	Other	**18**

Question 8: Currently there is an average of four interruptions each year. If this was reduced to three interruptions would you be happy to pay an additional $10 per month on your electricity bill?	Yes		**1**
	No		**2**
	Don't know/unsure		**3**
Question 8(a): If OtagoNet were to reduce your bill by $10 per month, would you be happy that the number of interruptions increased to five per year?	Yes		**1**
	No		**2**
	Don't know/unsure		**3**
Question 9: Do you intend to purchase an electric car in the next 12 months?	Yes	**1**	
	No	**2**	
Question 9(a): Or solar panels?	Yes	**1**	
	No	**2**	
Question 10: Who would you telephone in the event of the power supply to your home being unexpectedly interrupted? (Do not prompt)	Meridian Energy		**1**
	Contact Energy		**2**
	Mighty River Power		**3**
	TrustPower		**4**
	PowerNet		**5**
	OtagoNet		**6**
	Genesis Energy		**7**
	No one		**8**
	Other		**9**
Question 10(a): Have you made such a call within the last 6 months?	Yes	**1**	
	No	**2**	Go to Q 11
	Unable to recall	**3**	Go to Q 11
Question 10(b): Were you satisfied that the system worked in getting you enough information about the supply interruption?	Yes	**1**	Go to Q 10(d)
	No	**2**	Go to Q 10(c)
	Don't know/unsure	**3**	Go to Q 10(d)
Question 10(c): What, if anything, do you feel could be done to improve this system?			
Question 10(d): Were you satisfied with the information that you received?	Yes	**1**	Go to Q 11
	No	**2**	Go to Q 10(e)
	Don't know/unsure	**3**	Go to Q 11

Question 10(e): What, if anything, do you feel could be done to improve this information or the way in which it is delivered?

Question 11: What is the most important information you wish to receive when you experience an unplanned supply interruption? (Do not prompt)	Accurate time when power will be restored	**1**
	Reason for fault	**2**
	That they know problem and it is being fixed	**3**
	Other	**4**
	Specify	

Question 12: Are you aware of OtagoNet's 0800 faults number?	Yes	**1**
	No	**2**

Question 13: Finally, do you have any comments or suggestions about anything to do with OtagoNet which we haven't covered in our interview today?	No comments Nothing to add Happy with Service	**1**
Comment(s):		

This concludes our survey - Thank you for your time

Appendix 3 – Disclosure Schedules

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).
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		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
8	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
9	Consumer connection		4,776	4,553	3,332	4,550	2,638	2,316	2,750	2,805	2,861	2,507	2,977
10	System growth		3,549	2,431	580	334	2,052	2,219	13	13	1,526	1,557	1,588
11	Asset replacement and renewal		2,610	5,733	7,372	9,045	9,066	8,830	10,684	11,543	9,401	9,589	9,781
12	Asset relocations		1,211	119	122	124	127	130	276	404	413	421	429
13	Reliability, safety and environment:												
14	Quality of supply		250	418	548	559	571	194	463	472	481	491	501
15	Legislative and regulatory												
16	Other reliability, safety and environment		506	1,482	1,773	1,200	1,117	994	1,270	404	1,238	1,262	1,288
17	**Total reliability, safety and environment**		757	1,900	2,321	1,759	1,687	1,189	1,733	876	1,719	1,753	1,788
18	**Expenditure on network assets**		12,902	14,736	13,727	15,812	15,571	14,684	15,456	15,643	15,920	15,827	16,564
19	Expenditure on non-network assets												
20	**Expenditure on assets**		12,902	14,736	13,727	15,812	15,571	14,684	15,456	15,643	15,920	15,827	16,564
21													
22	*plus* Cost of financing												
23	*less* Value of capital contributions		1,392	773	789	804	821	839	856	873	891	908	927
24	*plus* Value of vested assets												
25													
26	**Capital expenditure forecast**		11,510	13,963	12,938	15,008	14,749	13,845	14,600	14,770	15,030	14,919	15,637
27													
28	Assets commissioned		12,133	15,198	13,104	13,888	16,440	15,622	14,667	17,533	15,920	15,827	16,564
29													
30		for year ended	*Current Year CY* **31 Mar 16**	*CY+1* **31 Mar 17**	*CY+2* **31 Mar 18**	*CY+3* **31 Mar 19**	*CY+4* **31 Mar 20**	*CY+5* **31 Mar 21**	*CY+6* **31 Mar 22**	*CY+7* **31 Mar 23**	*CY+8* **31 Mar 24**	*CY+9* **31 Mar 25**	*CY+10* **31 Mar 26**
31			**$000 (in constant prices)**										
32	Consumer connection		4,776	4,553	3,264	4,374	2,484	2,134	2,484	2,484	2,484	2,134	2,484
33	System growth		3,549	2,431	568	321	1,932	2,044	12	12	1,325	1,325	1,325
34	Asset replacement and renewal		2,610	5,733	7,220	8,694	8,535	8,134	9,648	10,220	8,160	8,160	8,160
35	Asset relocations		1,211	119	119	119	119	119	249	358	358	358	358
36	Reliability, safety and environment:												
37	Quality of supply		250	418	537	537	537	179	418	418	418	418	418
38	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
39	Other reliability, safety and environment		506	1,482	1,736	1,153	1,051	916	1,147	358	1,074	1,074	1,074
40	**Total reliability, safety and environment**		757	1,900	2,273	1,691	1,588	1,095	1,565	776	1,492	1,492	1,492
41	**Expenditure on network assets**		12,902	14,736	13,444	15,198	14,658	13,526	13,958	13,850	13,819	13,469	13,819
42	Expenditure on non-network assets		-	-	-	-	-	-					
43	**Expenditure on assets**		12,902	14,736	13,444	15,198	14,658	13,526	13,958	13,850	13,819	13,469	13,819
44													
45	**Subcomponents of expenditure on assets (where known)**												
46	Energy efficiency and demand side management, reduction of energy losses												
47	Overhead to underground conversion		1,211	60	60	60	60	60	60	60	60	60	60
48	Research and development												
49													
50													

51		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	69	177	155	183	267	322	378	374	493
55	System growth	-	-	12	13	120	175	1	2	201	232	263
56	Asset replacement and renewal	-	-	152	351	531	696	1,036	1,323	1,241	1,429	1,621
57	Asset relocations	-	-	3	5	7	10	27	46	54	63	71
58	Reliability, safety and environment:											
59	Quality of supply	-	-	11	22	33	15	45	54	64	73	83
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	36	47	65	78	123	46	163	188	213
62	**Total reliability, safety and environment**	-	-	48	68	99	94	168	100	227	261	296
63	**Expenditure on network assets**	-	-	282	614	912	1,158	1,498	1,793	2,101	2,359	2,745
64	Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**	-	-	282	614	912	1,158	1,498	1,793	2,101	2,359	2,745
66												

67		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
68	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	Major New Connections Projects	3,055	3,294	2,030	3,140	1,250	900
71	Other New Connections	1,721	1,259	1,234	1,234	1,234	1,234
72							
73							
74							
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	4,776	4,553	3,264	4,374	2,484	2,134
77	*less* Capital contributions funding consumer connection	900	703	703	703	703	703
78	**Consumer connection less capital contributions**	3,876	3,850	2,561	3,671	1,781	1,431
79	**11a(iii): System Growth**						
80	Subtransmission	941	-	-	59	749	792
81	Zone substations	1,002	1,628	388	-	1,075	1,138
82	Distribution and LV lines	1,522	435	180	12	108	114
83	Distribution and LV cables	10	250	-	250	-	-
84	Distribution substations and transformers	-	-	-	-	-	-
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	73	118	-	-	-	-
87	**System growth expenditure**	3,549	2,431	568	321	1,932	2,044
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	3,549	2,431	568	321	1,932	2,044
90							

91		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
92	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	645	1,465	2,024	2,347	2,208	2,089
95	Zone substations	562	200	665	1,686	1,651	1,606
96	Distribution and LV lines	1,403	4,068	4,532	4,661	4,676	4,439
97	Distribution and LV cables	-	-	-	-	-	-
98	Distribution substations and transformers	-	-	-	-	-	-
99	Distribution switchgear	-	-	-	-	-	-
100	Other network assets	-	-	-	-	-	-
101	**Asset replacement and renewal expenditure**	2,610	5,733	7,220	8,694	8,535	8,134
102	*less* Capital contributions funding asset replacement and renewal	10	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**	2,600	5,733	7,220	8,694	8,535	8,134
104							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21

11a(v):Asset Relocations

Project or programme *	$000 (in constant prices)					
Balclutha Main Street Undergrounding	653	-	-	-	-	-
Milton Main Street Undergrounding	139	-	-	-	-	-
include additional rows if needed						
All other project or programmes - asset relocations	419	119	119	119	119	119
Asset relocations expenditure	1,211	119	119	119	119	119
less Capital contributions funding asset relocations	482	70	70	70	70	70
Asset relocations less capital contributions	729	49	49	49	49	49

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21

11a(vi):Quality of Supply

Project or programme *	$000 (in constant prices)					
Reclosers with SCADA integration	245	239	358	358	358	-
include additional rows if needed						
All other projects or programmes - quality of supply	5	179	179	179	179	179
Quality of supply expenditure	250	418	537	537	537	179
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	250	418	537	537	537	179

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21

11a(vii): Legislative and Regulatory

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	-	-	-	-	-	-

150		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme **	**$000 (in constant prices)**					
153	Substation clearances and fence improvements	245	235	235	-	-	-
154	Substation structure seismic upgrades	61	60	353	353	251	-
155	Substation NER installation	88	418	239	239	239	239
156	33 kV Transformer Circuit Breakers	-	203	203	203	203	203
157	Milton 33kV ring protection upgrade	-	-	347	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	112	567	358	358	358	474
160	**Other reliability, safety and environment expenditure**	506	1,482	1,736	1,153	1,051	916
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	506	1,482	1,736	1,153	1,051	916
163							
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme **	**$000 (in constant prices)**					
169							
170							
171							
172							
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	-	-	-	-	-	-
177	**Atypical expenditure**						
178	*Project or programme **						
179							
180							
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	-	-	-	-	-	-

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).
This information is not part of audited disclosure information.

sch ref

7		*CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,061	984	1,004	1,023	1,045	1,068	1,133	1,156	1,179	1,202	1,226
11	Vegetation management	1,130	1,080	1,103	1,124	1,147	1,172	1,196	1,220	1,244	1,269	1,294
12	Routine and corrective maintenance and inspection	1,137	1,397	1,429	1,470	1,503	1,551	1,596	1,630	1,666	1,702	1,739
13	Asset replacement and renewal	653	497	507	517	1,053	539	550	622	572	584	595
14	**Network Opex**	3,981	3,957	4,043	4,134	4,748	4,330	4,475	4,628	4,661	4,757	4,855
15	System operations and network support	723	809	848	979	1,000	1,022	1,042	1,063	1,084	1,106	1,128
16	Business support	1,412	1,388	1,421	1,448	1,478	1,510	1,541	1,571	1,603	1,635	1,668
17	**Non-network opex**	2,136	2,198	2,269	2,427	2,478	2,532	2,583	2,634	2,687	2,741	2,796
18	**Operational expenditure**	6,117	6,155	6,312	6,560	7,226	6,862	7,057	7,262	7,348	7,498	7,651

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	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,061	984	984	984	984	984	1,023	1,023	1,023	1,023	1,023
23	Vegetation management	1,130	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
24	Routine and corrective maintenance and inspection	1,137	1,397	1,399	1,413	1,415	1,429	1,441	1,444	1,446	1,449	1,451
25	Asset replacement and renewal	653	497	497	497	991	497	497	551	497	497	497
26	**Network Opex**	3,981	3,957	3,960	3,973	4,470	3,989	4,041	4,097	4,046	4,048	4,051
27	System operations and network support	723	809	831	941	941	941	941	941	941	941	941
28	Business support	1,412	1,388	1,392	1,391	1,391	1,391	1,391	1,391	1,391	1,391	1,391
29	**Non-network opex**	2,136	2,198	2,223	2,332	2,332	2,332	2,332	2,332	2,332	2,332	2,332
30	**Operational expenditure**	6,117	6,155	6,182	6,305	6,803	6,321	6,373	6,430	6,378	6,381	6,383
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction											
33	of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	158	168	168	168	168	168	168	168	168	168	168

37 **Direct billing expenditure by suppliers that direct bill the majority of their consumers*

38

39		*CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	21	40	61	84	110	132	156	179	203
43	Vegetation management	-	-	23	44	67	92	116	140	164	189	214
44	Routine and corrective maintenance and inspection	-	-	29	57	88	122	155	187	220	254	288
45	Asset replacement and renewal	-	-	10	20	62	43	53	71	76	87	99
46	**Network Opex**	-	-	83	161	278	342	434	531	615	709	805
47	System operations and network support	-	-	17	38	59	81	101	122	143	165	187
48	Business support	-	-	29	56	87	119	149	180	212	244	276
49	**Non-network opex**	-	-	47	94	145	200	250	302	355	408	463
50	**Operational expenditure**	-	-	130	255	423	541	684	833	970	1,117	1,268

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					Asset condition at start of planning period (percentage of units by grade)						
7											
8	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	2.58%	4.99%	17.34%	54.94%	20.16%	3	5.00%
11	All	Overhead Line	Wood poles	No.	7.41%	23.24%	6.78%	38.90%	23.67%	3	15.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	8.39%	10.59%	1.12%	50.32%	29.57%	3	15.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	45.56%	47.72%	6.71%	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	84.02%	15.98%	4	-
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.	-	53.88%	35.02%	11.11%	-	3	7.69%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	100.00%	-	-	-	3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	13.33%	56.67%	30.00%	-	3	7.50%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	10.00%	85.56%	4.44%	-	3	11.11%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	100.00%	-	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	5.54%	22.17%	72.30%	-	3	5.79%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	11.43%	87.14%	1.43%	-	3	27.14%

39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	7.46%	80.18%	12.36%	-	3	9.62%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	8.04%	15.05%	21.48%	48.15%	7.27%	3	10.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	2.68%	17.42%	3.53%	61.22%	15.16%	3	10.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	38.65%	61.35%	N/A	5.00%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	9.40%	90.60%	N/A	-
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 sectio	No.	-	15.38%	53.85%	30.77%	-	3	53.85%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	100.00%	-	4	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	20.37%	74.89%	4.74%	-	2	10.00%
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.	-	-	39.29%	60.71%	-	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.55%	0.79%	18.85%	2.10%	76.72%	3	2.50%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	-	12.72%	87.28%	4	-
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	76.47%	23.53%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	8.98%	17.11%	7.13%	66.78%	-	2	15.00%
56	LV	LV Cable	LV UG Cable	km	-	-	-	10.58%	89.42%	N/A	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	100.00%	N/A	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	100.00%	N/A	-
59	All	Protection	numeric)	No.	-	16.16%	47.94%	35.89%	-	3	18.33%
60	All	SCADA and communications	SCADA and communications equipment operating as a sir	Lot	-	4.85%	63.03%	32.12%	-	3	
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	50.00%	25.00%	25.00%	-	3	25.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

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**

8

	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Charlotte Street	5.5	5.0	N-1	3	111%	5.0	111%	Transformer	Over N-1 but load transfer available
10	Clarks Junction	0.3	-	N	-	-	-		No constraint within +5 years	
11	Clinton	1.8	-	N	1	-	-		No constraint within +5 years	
12	Clydevale	3.4	-	N	1	-	-		No constraint within +5 years	Capacity increase to 5 MVA N-security site underway
13	Deepdell	0.1	-	N	-	-	-		No constraint within +5 years	
14	Elderlee Street	5.0	5.0	N-1	3	99%	5.0	99%	No constraint within +5 years	Load transfer available to Milburn and Glenore
15	Finegand	1.1	-	N	1	-	-		No constraint within +5 years	
16	Glenore	0.6	-	N	1	-	-		No constraint within +5 years	
17	Golden Point	-	-	N	-	-	-		No constraint within +5 years	Load transferred to Macraes end 2013, now standby substation only
18	Greenfield	1.6	-	N	-	-	-		No constraint within +5 years	
19	Hindon	0.2	-	N	-	-	-		No constraint within +5 years	
20	Hyde	1.3	-	N	1	-	-		No constraint within +5 years	
21	Kaitangata	1.3	-	N	1	-	-		No constraint within +5 years	
22	Lawrence	1.3	-	N	1	-	-		No constraint within +5 years	
23	Linnburn	0.9	-	N	-	-	-		Other	Temporary sub to be made obsolete by Patearoa sub expansion
24	Merton	2.9	2.5	N-1	2	114%	5.0	57%	Transformer	Over N-1 capacity, replacement Waikouaiti substation planned
25	Middlemarch	0.8	-	N	1	-	-		No constraint within +5 years	
26	Milburn	2.1	2.5	N-1	3	83%	2.5	83%	No constraint within +5 years	
27	North Balclutha	2.7	-	N	3	-	-		No constraint within +5 years	
28	Oturehua	0.2	-	N	-	-	-		No constraint within +5 years	
29	Owaka	1.5	-	N	1	-	-		No constraint within +5 years	
30	Paerau	0.3	-	N	-	-	-		No constraint within +5 years	
31	Paerau Hydro	12.1	15.0	N-1	-	81%	15.0	81%	No constraint within +5 years	
32	Palmerston	2.4	2.5	N-1	1	95%	2.5	105%	Transformer	Relocation to Transpower site planned (beyond 5 yrs) monitor growth
33	Patearoa	1.5	-	N	1	-	10.0	52%	Transformer	Site expansion and second subtransmission supply planned
34	Port Molyneux	0.6	-	N	1	-	-		No constraint within +5 years	
35	Pukeawa	0.5	-	N	-	-	-		No constraint within +5 years	
36	Ranfurly	2.1	2.5	N-1	1	84%	2.5	92%	No constraint within +5 years	Monitor growth
	Remarkables	3.2	12.5	N-1	-	26%	12.5	51%	No constraint within +5 years	
38	Stirling	4.2	-	N	1	-	-		No constraint within +5 years	
39	Waihola	1.1	-	N	1	-	-		No constraint within +5 years	
40	Waipiata	1.4	-	N	1	-	-		No constraint within +5 years	Planned load transfer to Patearoa
41	Waitati	1.5	-	N	1	-	-		No constraint within +5 years	
42	Wedderburn	0.2	-	N	-	-	-		No constraint within +5 years	

43 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

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

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

	Number of connections					
	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
*Consumer types defined by EDB**						
Consumer Connections <20 kVA	221	210	210	160	210	210
Consumer Connections <21-99 kVA	48	37	29	33	31	31
Consumer Connections >100 kVA	4	5	6	7	5	5
Connections total	273	252	245	200	246	246

**include additional rows if needed*

Distributed generation

Number of connections	25	35	35	35	35	35
Capacity of distributed generation installed in year (MVA)	0.10	0.15	0.15	0.15	0.15	0.15

12c(ii) System Demand

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
Maximum coincident system demand (MW)						
GXP demand	49	61	62	64	65	66
plus Distributed generation output at HV and above	19	7	7	7	7	7
Maximum coincident system demand	68	68	69	71	72	73
less Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
Demand on system for supply to consumers' connection points	68	68	69	71	72	73
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	343	348	353	357	363	368
less Electricity exports to GXPs	-	-	-	-	-	-
plus Electricity supplied from distributed generation	102	103	104	105	105	106
less Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
Electricity entering system for supply to ICPs	445	451	457	462	468	474
less Total energy delivered to ICPs	423	428	434	439	445	451
Losses	22	22	23	23	23	23
Load factor	75%	76%	76%	74%	74%	74%
Loss ratio	5.0%	5.0%	5.0%	5.0%	4.9%	4.9%

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	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
10	**SAIDI**						
11	Class B (planned interruptions on the network)	80.7	148	148	148	148	148
12	Class C (unplanned interruptions on the network)	186.3	169.9	164.7	160.8	156.8	154.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.33	0.64	0.64	0.64	0.64	0.64
15	Class C (unplanned interruptions on the network)	2.69	2.36	2.33	2.3	2.27	2.25

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 .

Q No.	Function	Question	Score	Maturity Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	The long-term asset management strategy takes account of the lifecycle of some, but not 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?	2	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.
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?	2	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.
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)	2	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.
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?	2	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.
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?	2	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.
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)?	2	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	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?	2	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.
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?	1	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.
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?	2	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 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?	2	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	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?	2	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.
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?	2	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.
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?	2	The organisation is in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non-conformance?	2	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of noncompliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.
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?	1	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.
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.

Appendix 4 – Policies, Standards and Procedures

Operating Processes and Systems

Commissioning Network Equipment	PNM-061
Network Equipment Movements	PNM-063
Planned Outages	PNM-065
Network Faults, Defects and Supply Complaints	PNM-067
Major Network Disruptions	PNM-069
Use of Operating Orders (O/O)	PNM-071
Control of Tags	PNM-073
Access to substations and Switchyards	PNM-075
Operating Authorisations	NMPR-040
Radio Telephone Communications	PNM-079
Operational Requirements for Live Line Work	PNM-081
Control of SCADA Computers	PNM-083
Operating Near Electrical Works	PNM-085
Customer Fault Calls/Retail Matters	PNM-087
Site Audits	PNM-088
Meter/Ripple Receiver Control	NMPR-005

Maintenance Processes and Systems

Transformer Maintenance	NMPR-030
Defect Submission & Retrieval from the NEDeRS Database	PNM-066
Control of Network Spares	PNM-097
Maintenance Planning	PNM-105
Network Overhead Lines Equipment Replacement	PNM-106
Earth Tests	PNM-133

Other maintenance is to manufacturers' recommendations or updated industry practise.

Renewal Processes and Systems

Network Development	PNM-113
Design and Development	PNM-114

Up-sizing or Extension Processes and Systems

Processing Installation Connection Applications	PNM-123
Network Development	PNM-113
Design and Development	PNM-114
Easements	PNM-131

Retirement Processes and Systems

Disconnected and/or Discontinued Supplies	PNM-125

Performance Measuring Processes

These processes are embedded within, and controlled by, the outage, faults and defects databases.

Other Business Processes

In addition to the above processes that are specific to life cycle activities, OJV has a range of general business processes that guide activities such as evaluating tenders and closing out contracts:

Setting Up the Project	PNM-010
Tendering	NMPR-045
Progressing the Project	PNM-020
Construction Approval	PNM-025
Materials Management	PNM-030
Project Control	PNM-035
Project Close Out	PNM-040
Customer Satisfaction	PNM-050
Internal Quality Audits	PNM-055
Drawing Control	PNM-089
Network Operational Diagram/GIS Control	PNM-091
Control of Operating and Maintenance Manuals	PNM-093
Control of External Standards	QYPR-005
Control of Power Quality Recorders	PNM-103
Quality Plans	PNM-107
Contractor Health and Safety	PNM-109
Network Accidents and Incidents	PNM-111
Design and Development	PNM-114
Network Purchasing	PNM-115
Network Pricing	PNM-117
Customer Service Performance	PNM-119
Incoming and Outgoing Mail Correspondence	PNM-129