Electricity Invercargill Ltd

Asset Management Plan 2016 - 2026

Publicly disclosed in March 2016

Contents

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0. Summary

Background and Objectives

Electricity Invercargill Limited (EIL) is the electricity lines business that conveys electricity to the majority of Invercargill and to Bluff for approximately 17,333 customers.

EIL's Asset Management Plan (AMP) provides an internal asset management framework for EIL's network. Disclosure in this format is also intended to meet the requirements of the Electricity Distribution Information Disclosure Determination 2012. It covers the ten year planning period from 1 April 2016 to 31 March 2026. Other key asset management documents for EIL are;

- The Annual Works Programme (AWP) detailing the capital and operational 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.
- The Statement of Intent which is the principal accountability mechanism between EIL's Board and the shareholder; Invercargill City Holdings.

EIL's business goals are driven by its stakeholder's 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 EIL's commercial operation, investment, risk management, business efficiency and customer satisfaction objectives.

EIL's commercial goal is to deliver a sustainable earnings stream to their shareholder that is the best use of their funds. This creates a primary driver for EIL and formal accountabilities to the shareholder are in place for financial and network performance. Customers via the electricity retailers provide EIL's revenue in return for the services provided by the EIL network assets. Due to the importance EIL 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.

EIL has a network management contract with PowerNet Limited which it jointly owns with The Power Company Limited (TPCL). The AMP is produced by PowerNet after extensive consultation throughout the business, with EIL's Board of directors and EIL's customers. The AMP is approved by the EIL Board prior to the end of March of each year when it is publically disclosed.

Assets Covered

EIL's service area includes two fully urban, geographically separate areas comprising of the city of Invercargill (except for some of the outer regions supplied from the surrounding TPCL network) and the township of Bluff. The Invercargill area network is almost entirely underground after an extensive program converting overhead lines to underground cable except for a few streets remaining as overhead construction. The Bluff network also remains as overhead line due to the rocky subsurface making undergrounding difficult.

EIL supplies 17,333 residential, commercial and industrial customers across the two network areas. Transpower's Invercargill GXP substation is the 33kV supply point for both network areas however a limited backup supply is available from the North Makarewa GXP. Bluff is supplied at 11kV via TPCL's overhead subtransmission and Bluff zone substation. EIL's subtransmission has a total length of 27.6km and comprises a mix of oil filled and XLPE cables supplying the four Invercargill zone substations. The distribution network has a total length of over 182km with all feeders operating at 11kV. Via more than 400 distribution substations comprising 11kV switchgear and distribution transformers the distribution network supplies over 450km of low voltage network operating at 400/230V.

The undergrounding program has meant much of the network has been replaced since the late 1950s and the distribution network is relatively young. However the oldest assets are at end of life and due for replacement, especially 11kV switchgear.

Service Levels

EIL set and maintain a number of service levels on behalf of its stakeholders especially its customers. Two important metrics measuring network reliability are SAIFI and SAIDI;

- SAIFI is a measure around outage frequency which translates to the average number of faults an average customer would experience annually. EIL is forecasting a SAIFI of about 0.6 times.
- SAIDI is a measure around outage duration which translates to the average amount of time an average customer would be without power annually. EIL is forecasting SAIDI of about 21 minutes.

These forecasts are average values around which significant variation can be expected due to the random occurrence of a low number of faults and weather impacts. EIL's network reliability has been extremely good due to the underground network in Invercargill and forecasts are for a slight improvement in future years.

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 EIL 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 EIL are required to set financial efficiency and energy efficiency service levels. EIL has decided to update the financial efficiency ratios and will now trend and set targets for both network and non-network operational expenditure per each of ICPs supplied, km of network length and total distribution transformer capacity. These ratios are disclosed directly by the other distribution businesses and therefore are able to be used for benchmarking EIL's performance against its industry peers. Targets for network operational expenditure ratios are set as; per ICP - $92, per km $2,398 and per MVA $10,504 and targets for non-network operational expenditure ratios are set as; per ICP - $179, per km $4,646 and per MVA $20,347.

For efficiency of energy delivery EIL is aiming to achieve an overall load factor of 50%, capacity utilisation of 40% and loss ratio of 5.5%. It is a long term average that EIL hopes to achieve for these measures as year to year variation can be significant and often largely out of EIL's control.

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

Development

Network development is primarily associated with creating additional network capacity for supplying increasing demand while maintenance or improvement of service levels may also create drivers for development. Several development triggers have been identified and are monitored to determine 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.

Predicting when development triggers will be reached in future years enables EIL to plan effectively for future projects and this requires forecasts for demand growth. Historical demand is trended and projected into future years accounting for foreseeable future drivers that may cause any change to the current trend. Projections and associated planning around future expected constraints are based on what is considered the most likely scenario while EIL's strategy of deferring capital expenditure until necessary minimises the risk of overinvestment.

EIL's work program includes the following capital expenditure on network development:

- Consumer Connections – the provision of a connection point and additional network capacity as needed for new customers is budgeted at $270 thousand.
- System Growth – a small budget of $47 thousand is allowed for minor tidy up work at zone substations following the construction of the new Spey Street zone substation and reconfiguration of the Doon Street substation site. Future work to complete reconfiguration at Doon Street and undertake a major upgrade of the Southern zone substation has been deferred until the year 2019/20 and is budgeted at $2,502 thousand.
- Asset Relocations – a small budget of $6 thousand is allowed for the relocation of poles or pillar boxes as may be needed from time to time.
- Quality of Supply – network upgrades to ensure sufficient voltage is delivered at customer connection points and automation of network equipment to allow faster location, isolation and supply restoration following a fault is budgeted at $95 thousand.
- Reliability, Safety and Environmental – other projects budgeted at $155 thousand which is allowed for the retrofit of arc-flash protection on the 11kV switchboard and for the installation of a neutral earthing resistor to limit earth fault current at the Leven Street zone substation.

Total capital expenditure is budgeted at $3,278 thousand, $4,905 thousand and $4,551 thousand for the years 2016/17, 2017/18 and 2018/19 respectively including Asset Replacement and Renewal described under Lifecycle below.

Lifecycle

Once development drivers have established the need for an asset it must be managed throughout its lifecycle to create and maintain the fulfilment of the assets purpose as long as it is required and to minimise any adverse effects the asset might create. Following procurement, installation and commissioning, an asset enters its useful service life where it will often be operated over a considerable time period. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service. At some point continuing to maintain an asset will become uneconomic and provided the need for the asset remains it will replaced while the retired asset is disposed of appropriately.

EIL'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 budgeted at $2,706 thousand, $4,520 thousand and $4,230 thousand for the years 2016/17, 2017/18 and 2018/19 respectively. This includes significant projects spanning the next three years to relocate underground distribution substations and link boxes to above ground locations as prioritised to improve network safety.

The remainder of EIL'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 $104 thousand each year ongoing.
- Vegetation Management – a small budget of $1 thousand 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 $795 thousand 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 $700 thousand each year ongoing.

Total network operational expenditure is budgeted at about $1,600 thousand each year ongoing. Additionally non-network operational expenditure is budgeted between $3,100 and $3,194 thousand each year ongoing consisting of System Operations and Network Support at $681 to $733 thousand and Business Support at $2,419 to $2,463 thousand.

Risk Management

EIL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. Firstly risks associated with EIL's network are actively identified through regular reviews. Identified risks are then quantified in terms of the probability that an adverse occurrence would eventuate and the consequences for EIL if it does. 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)

EIL'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 be prioritised 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 EIL has developed a Business Continuity Plan and has a Pandemic Action Plan for use in the outbreak of any highly infectious illness. EIL also holds critical network spares and has contingent operating plans to support efficient restoration of supply following unexpected equipment failure as well as holding a range of business insurances.

Performance

For the financial year 2014/15 EIL's performance is summarised as follows.

Capital expenditure was 19.1% under target due to two main factors;

- Delays incurred in obtaining satisfactory designs and associated re-evaluation of the most economic development options.
- Customer connection rate was low compared with other years and asset replacements were lower than anticipated with inspections identifying limited reactive work requirements.

Operational expenditure was 34.1% under target with reactive work identified through inspections lower than anticipated.

Reliability performance on the overall network was good, with SAIFI 21% under the target of 1.0 and SAIDI 3% over the target of 40 minutes. These results were well within the Commerce Commission's supply quality limits.

EIL's financial efficiency results were good with the ratio OPEX/RC well below target and Indirect Costs per Customer comfortably below target; achieving 3.09% and $113.58 respectively.

Network efficiency performance was fair with the target of greater than 50% for Load Factor achieved however the Loss Ratio and Capacity Utilisation targets were not achieved. Both results were within 12% of target and EIL recognises that these results are variable and it is a long term average which EIL aims to achieve.

Capability to Deliver

EIL have many systems including processes and tools to effectively and efficiently manage its network assets. Dedicated staff are required to maintain and update these systems and the information that they contain. A great deal of data is held about EIL's network assets including technical details, location, operational states and condition. The systems that hold this data help in collating and displaying information in various ways to support efficient decision making for EIL's asset management planning and activities.

EIL's business is funded from the revenue received from customers via several electricity retailers and in return EIL 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 resource is an ongoing issue that EIL is managing and EIL's Annual Works Program recognises existing constraints and future resourcing levels as constraints are managed over time. EIL uses internal field services to carry out much of the operational, maintenance and development work on its network but also utilises local contractors where additional resources are required.

1. Background and Objectives

Electricity Invercargill Limited (EIL) is the electricity lines business that conveys electricity to the majority of Invercargill and to Bluff for approximately 17,333 customer connections on behalf of twelve energy retailers. The wider EIL entity also includes the following associations;

- A 50% stake in PowerNet, an electricity lines management company jointly owned with The Power Company Limited (TPCL). This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 24.9% stake in Electricity Southland Limited (ESL), which distributes electricity in the Frankton area of Central Otago.
- A 24.9% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of EIL, TPCL and ESL.
- A 25.9% stake in Peak Power Services Ltd, an electrical contracting company based in Frankton.
- A 25% stake in Southern Generation Ltd, a generation company with wind and hydro assets in New Zealand jointly owned with TPCL and Pioneer Generation Ltd.

The interrelationship of these entities with the various holding companies and shareholders, along with the accounting treatment of results, is described in EIL's annual report.

1.1. Purpose Statement

The purpose of EIL's Asset Management Plan (AMP) is to provide an internal governance and management framework for asset management practice on EIL'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

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

- Set service levels of the electricity distribution services supplied by EIL 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 EIL'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 EIL'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 EIL'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 EIL uses and will use to manage the assets.

1.3. AMP Planning Period and Director Approval

EIL'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 EIL's Board on 31 March 2016 (see Appendix Directors Approval) 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. Response to service interruptions is probabilistic by nature and due to the low number of faults on EIL's network can be quite sporadic. Network faults on overhead parts of the network are even less predictable being 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

EIL's business goals are driven by its stakeholder's 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 EIL's stakeholders, their interests in EIL, how these interests are met and how conflicts between stakeholder's expectations are managed before identifying other influences that drive and shape EIL's business.

Stakeholder Interests

The stakeholders EIL 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 EIL'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 EIL (be it equity or debt).
- Pay money to EIL (either directly or through an intermediary) for delivering service levels.
- Is physically connected to EIL's network.
- Use EIL's network for conveying electricity.
- Supply EIL 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 EIL 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
Invercargill City Holdings (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Energy Safety				✓	✓
Industry Representative Groups	✓	✓	✓		
Public (as distinct from customers)				✓	✓
Mass-market Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Energy Retailers	✓	✓	✓		
Suppliers of Goods and Services	✓				
Land owners				✓	✓
Bankers	✓	✓		✓	✓

Table 2: Identifying stakeholder's interests

Stakeholder	How Interests are Identified
Invercargill City Holdings (Shareholder)	• 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)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PNL Staff
Ministry of Business, Innovation & Employment	• Release of legislation, regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website

Stakeholder	How Interests are Identified
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 EIL'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 EIL's treasury/borrowing policy • By adhering to banking covenants

Table 3: Accommodating Stakeholder's Interests

Interest	Description	How EIL 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 EIL.	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 EIL's customers want.	EIL'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. EIL's pricing methodology is expected to be cost-reflective,

Interest	Description	How EIL Accommodates Interests
		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 carriage way within the constraints faced in regard to private land and road reserve.
Compliance	Compliance is necessary with many 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.

EIL's commercial goal is to deliver a sustainable earnings stream to their shareholder Invercargill City Holdings that is the best use of their funds. This creates a primary driver for EIL and formal accountabilities to the shareholder are in place for financial and network performance. See section Key Planning Docs (Statement of Intent).

Customers via the electricity retailers provide EIL's revenue in return for the services provided by the EIL network assets. Due to the importance EIL places on meeting customer's expectations annual customer surveys are undertaken to monitor customer satisfaction, with service level targets set to ensure standards are maintained or improved. See sections Service levels and Performance for details of these surveys, customer feedback and performance targets EIL sets.

EIL is also subject to the requirement to compile and publically disclose performance and planning information (including the requirement to publish an AMP) and EIL 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.

EIL 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.

Managing Conflicting Stakeholder Interests

When a conflict of stakeholder interests has been identified EIL 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 EIL will cease to exist which makes supply quality and compliance pointless.
3. **Pricing**. EIL will give third priority to pricing as a follow on from viability (noting that pricing is only one aspect of viability). EIL 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 makes customers, and therefore EIL, 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 EIL Board if appropriate.

Other Influences

There are several other issues that are not directly related to stakeholders but have a significant impact on EIL'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 EIL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, that could strand conventional wire utilities.
- Local, national and global economic cycles which effect growth and development.
- Changes to the Southland 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 EIL'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 EIL 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 EIL'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 (say if the transport agency required all poles to be moved back from the carriage way).

1.5. Strategy and Delivery

EIL'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.

Vision Statement

To be the top performing New Zealand Lines Company.

Corporate Strategy

Key corporate drivers from EIL's Strategic Plan are:

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

Asset Management Strategy

EIL's asset management strategy follows these guiding principles:

- Safety by design using the ALARP (as low as reasonable 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

Interaction of Goals/Strategies

EIL’s 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

Asset Management Strategies \ Corporate Strategies	Strive to be an efficient but effective operation.	Manage operations in a progressive and commercial manner.	Understand and effectively manage appreciable business risk.	Undertake new investments which are ‘core business’, acceptable return for risk involved, and maximise commercial value.	Provide its customers with above average levels of service.
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
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 EIL's behalf and approved by EIL as part of the company's planning processes.

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 Capability to deliver.

Annual Business Plan

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

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

- Core Business, Vision Statement and Critical Success Factors
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Polices
- 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.

Statement of Intent

EIL's Statement of Intent (SOI) is a requirement under the constitution of the company, and forms the principal accountability mechanism between EIL's Board and the shareholder; Invercargill City Holdings. EIL's corporate strategies gain shareholder approval via the SOI.

The SOI includes financial performance projections for:

- EBIT% (Percentage Group Earnings Before Tax and Interest on Assets Employed),
- NPAT% (Percentage Group Tax Paid Profit on Equity) and
- Percentage of Consolidated Equity to Total Assets

It also includes the quality performance projections for SAIFI and SAIDI which are set in the AMP Proposed Service Levels.

These projections are given over a three year period, form the heart of the asset management activity and implicitly recognise the inherent trade-off between price and supply quality. The SOI is available at http://www.powernet.co.nz in the Line Owners area under Company Information.

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

The interaction between EIL's corporate 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 EIL'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 EIL's asset management company PowerNet and for the EIL board.

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with EIL'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.

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 EIL'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 EIL Board. The SOI incorporates performance targets from the AWP including key asset management targets forming the accountability mechanism between the EIL Board and the shareholder.

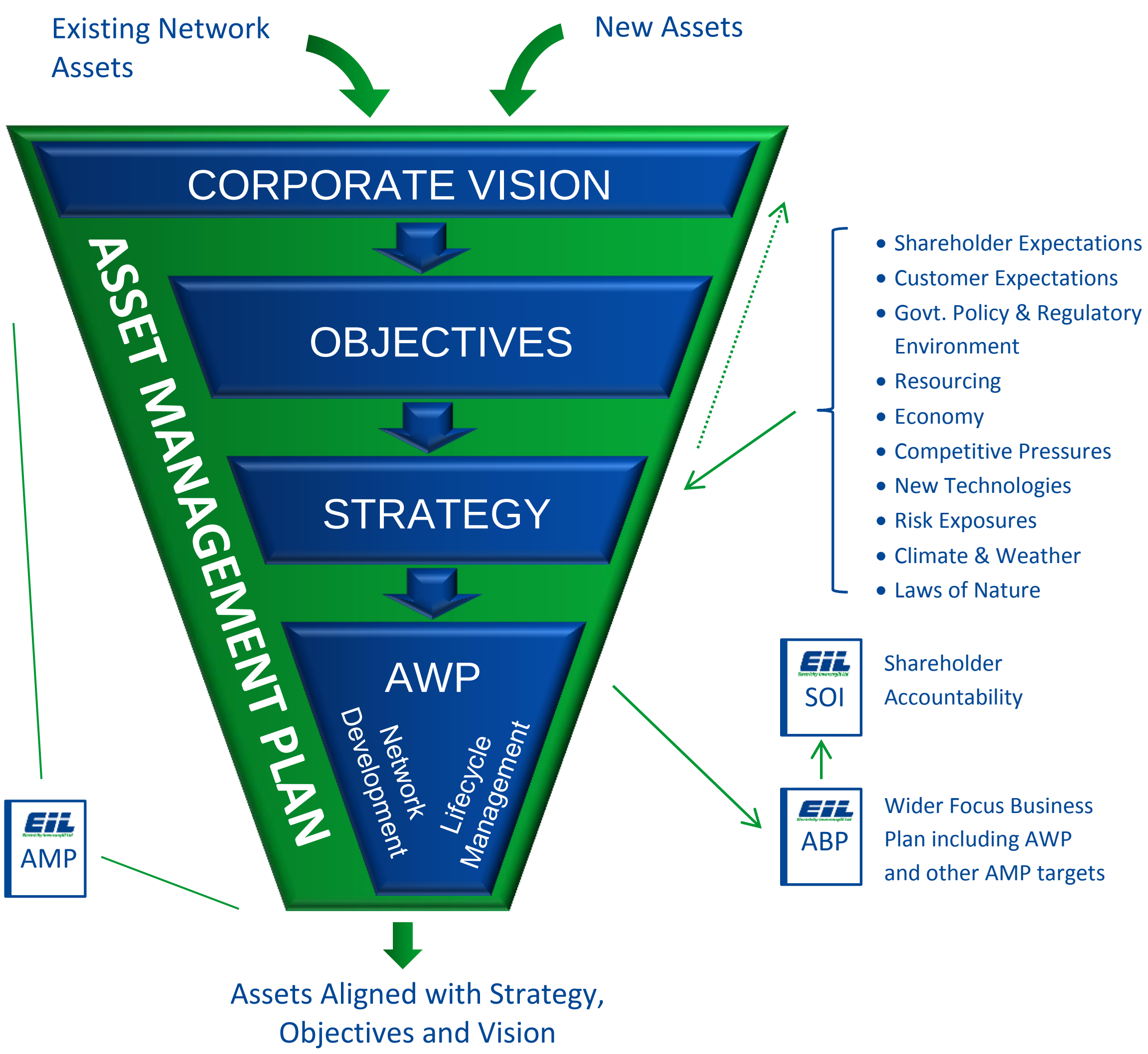

Figure 1: Interaction of Objective, Strategies and Key Plans

1.8. Accountabilities and Responsibilities

Accountability at Ownership Level

EIL has a single shareholder – Invercargill City Holdings (Holdco) acting for Invercargill City Council as a CCTO (council controlled trading organisation). The CCTO currently has five directors;

- Cam McCulloch (Chairman)
- Graham Sycamore
- Alan Dennis
- Tim Loan
- Lindsay Thomas

Directors are appointed to Holdco and subsidiary company directors are approved by Invercargill City Council.

Accountability at Governance Level

As EIL 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 EIL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes EIL's Board intimately accountable to EIL's shareholder for these important asset management outcomes whilst the inclusion of financial targets in the statement makes EIL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. EIL currently has five directors:

- Neil Boniface (Chairman)
- Tom Campbell
- Ross Smith
- Darren Ludlow
- Sarah Brown

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

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 EIL's Board and PowerNet.

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.

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. Major projects typically utilise external consultants and contractors while technical and distribution projects utilise PowerNet's in-house field services.

Where external contractors are required contracts will be utilised, 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.

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 and include;

- DECOM Limited
- Broadspectrum Limited
- Electrix Limited
- Peak Power Services Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Asplundh Tree Expert (NZ) Limited
- Cory's Limited
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Partnerships)

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

Key Reporting Lines

EIL's ownership, governance and management structure is depicted in Figure 2:

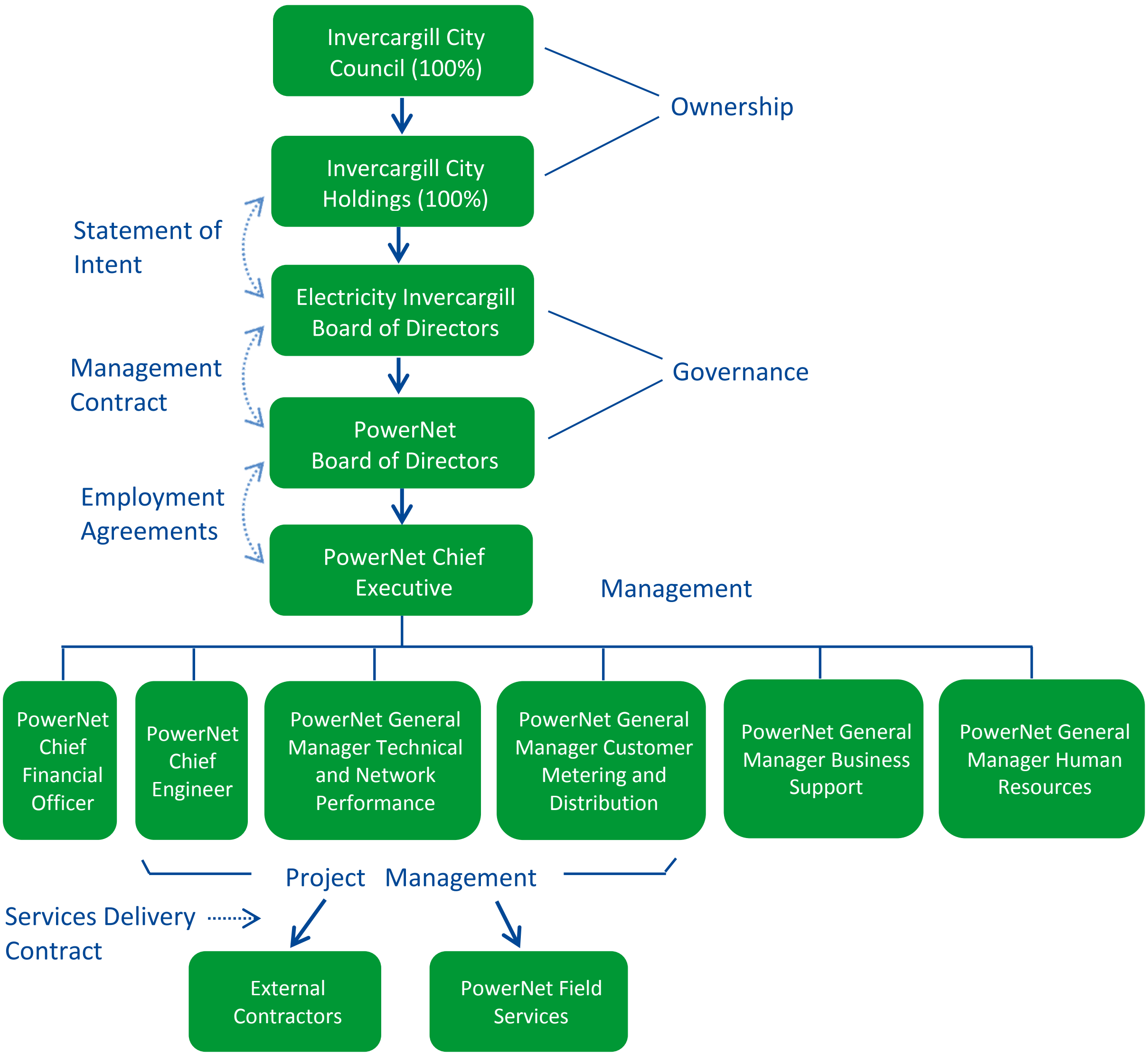

Figure 2: Governance and management accountabilities

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

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 EIL Board as part of ABP process in the previous year.

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.

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. Additionally this process tends to be one of moving goal posts as variations generally need to be accounted for up until the information disclosure date.

Governance Participation

The initial consolidated AWP is submitted to the EIL Board 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 Board 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 Board may need to consider, for example strategy updates, may be presented at this stage for review.

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

Post Disclosure Communication

Once the AMP has been finalised and 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 "heads up" communication meeting is held with internal field staff and key contractors invited to highlight the body of work for the year ahead, especially 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.

Again planners are 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 what is considered the most likely scenario 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.

Demand growth rates (including effects of generation) are discussed in Forecasting Demands and Constraints. The drivers of future demand described are as per the most likely scenario and this section discusses how EIL manages the risk of different patterns of growth eventuating.

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 harsh coastal Bluff environment tends to shorten life.

No significant change in present regulation is anticipated. 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.

Project costs and timeframes are estimated based on previous experience and anticipated resourcing. Other than the disclosure schedules included in Appendix 3 all figures are represented as constant 2016 dollars and assume no significant variation in exchange rates where applicable.

1.11. Potential Variation Factors

The following factors have the potential to cause significant variation between the forecasts set out in this AMP and the actual information that will be disclosed in future disclosures;

- Cost and time estimate inaccuracies
- Variation in inflation rates and exchange rates
- Staffing resource losses or inability to recruit as required
- Reactive work varying from that estimated
- Equipment failure (especially large capital plant) may influence future economic options
- New safety issues identified and initiatives created
- Reprioritisation of projects with identification of new work activities, realisation of preferable project options or new knowledge gained
- 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 EIL's assets and asset configurations, but begins by describing EIL'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

EIL's service area includes two geographically separate areas:

- The part of Invercargill bounded by Racecourse Road to the east, the Waihopai Stream to the north and west (except for Invercargill Airport which is in EIL's area) and Elizabeth, Moulson and Brown Streets and Tramway Road to the south. Shown in Figure 3.
- The borough of Bluff extending as far west as the former Ocean Beach freezing works. Shown in Figure 4.

Note for the purposes of information disclosure Bluff, 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 EIL are generally inclusive of those for the Bluff area network.

The topography is densely urban and built-up in both Invercargill and Bluff. Invercargill is almost totally flat (lying about 3m to 5m above sea level) whilst Bluff varies from flat to steep hills.

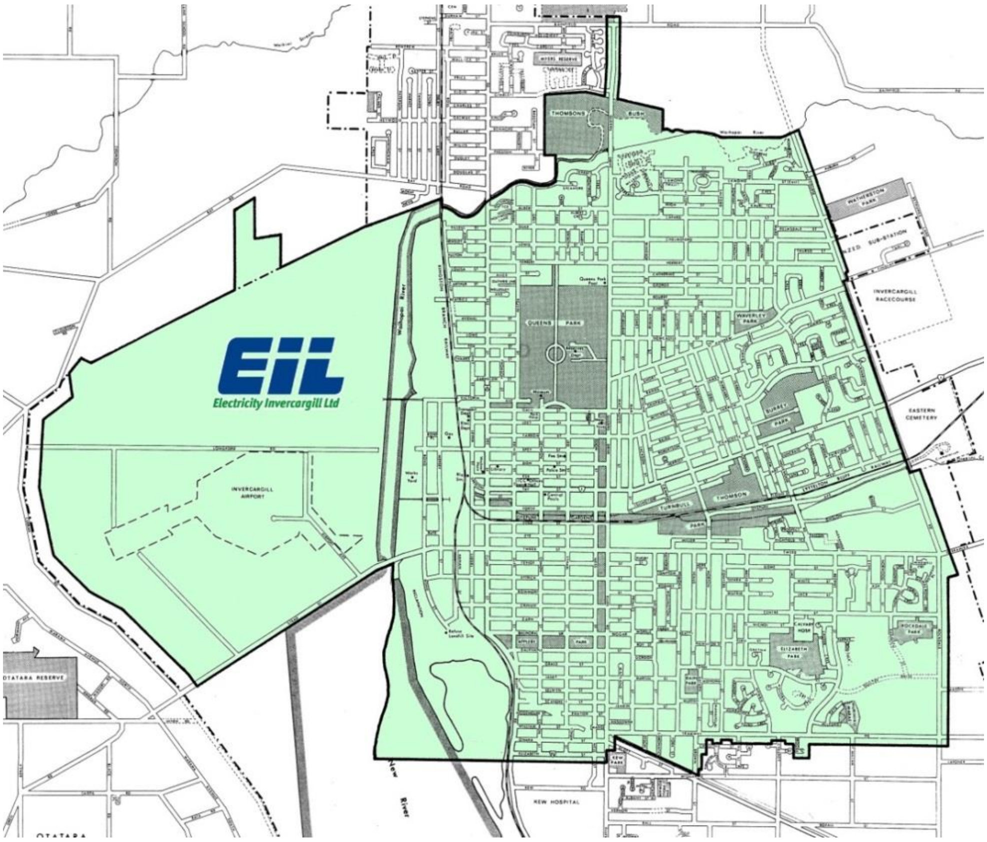

Figure 3: EIL Invercargill Distribution Area

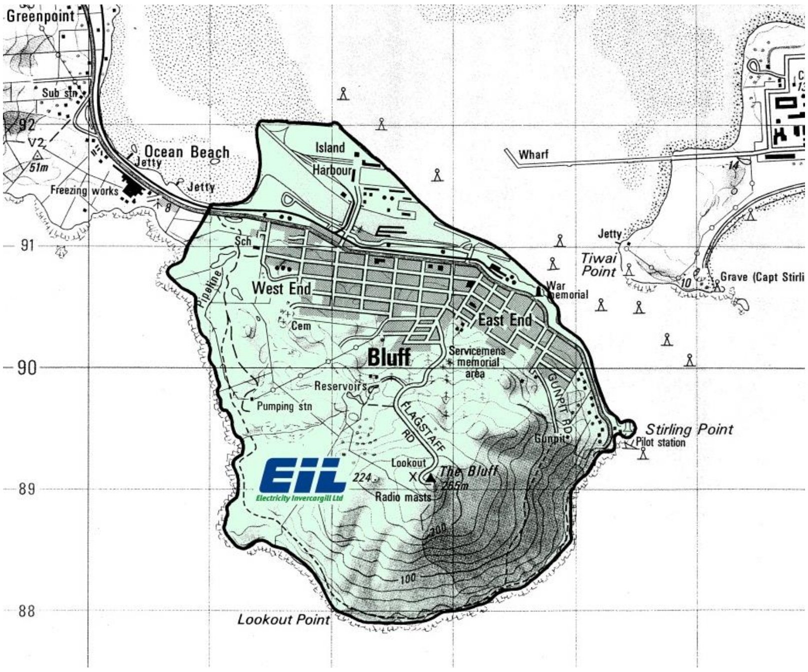

Figure 4: EIL Bluff Distribution Area

Key Industries

EIL's largest customer is a large port in the Bluff distribution area which regularly peaks at about 1.6MW and consumes approximately 6.5GWh per year.

No individual EIL customers are considered large enough to have any significant impact on network operations or asset management planning other than ensuring that adequate supply capacity is maintained.

Certain areas on the network have differing load densities and rates of growth which are more likely to influence asset management planning. Growth rates on the network however are relatively low and connections for new large customers are generally unpredictable so planning tends to be more reactive than proactive to avoid over investment.

The Bluff distribution area also includes port associated heavy industries as well as residential and commercial customers.

The Invercargill distribution area is predominantly residential but does include a medium-sized CBD, a heavy industrial area immediately west of the CBD and a light industrial area in the south east. The criticality of supply for the CBD as a whole is recognised with additional protection and automatic sectionalisation provided in this area.

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.

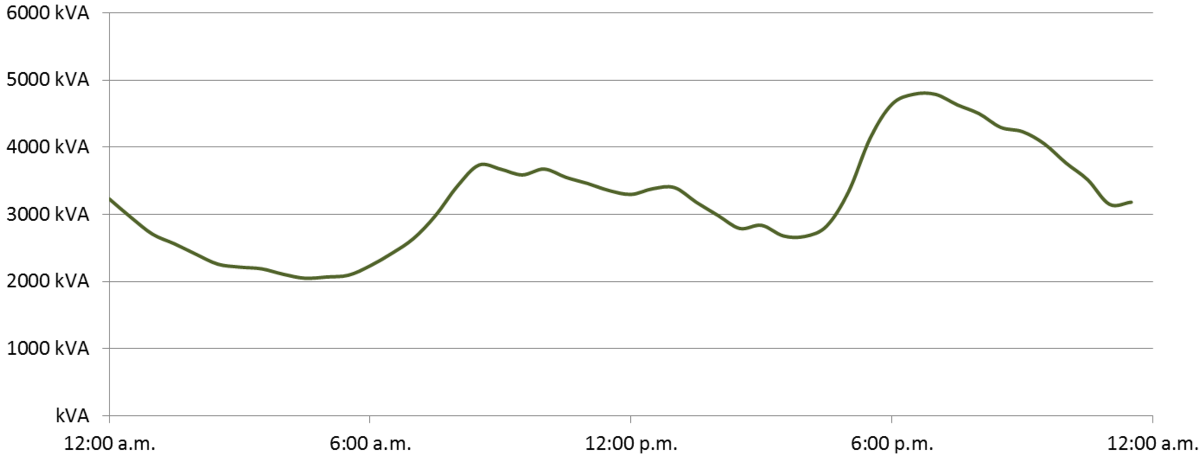

Figure 5: Typical Domestic Daily Load Profile (July, Racecourse Road CB8)

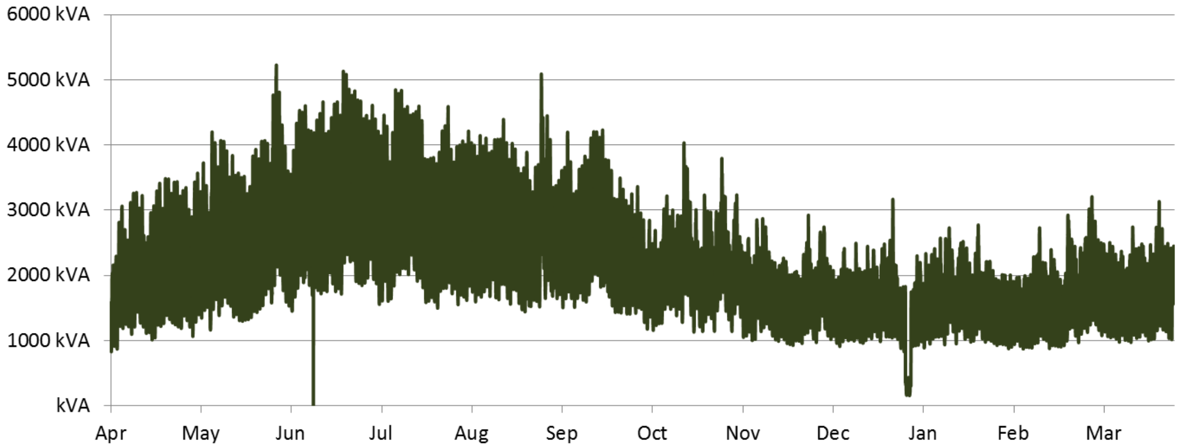

Figure 6: Typical Domestic Feeder Yearly Load Profile (Racecourse Road CB8)

CBD: Load peaks in the CBD later in the day (10am-12pm) as people migrate into the area for their work day. Week day loading is typically significantly higher than over the weekends corresponding to work patterns of the businesses in the CBD. Seasonal variation in the CBD load profile is similar to that of domestic loading with peak load occurring over the winter months. The CBD profiles shown in Figure 7 and Figure 8 include some industrial load which tends to follow similar consumption patterns.

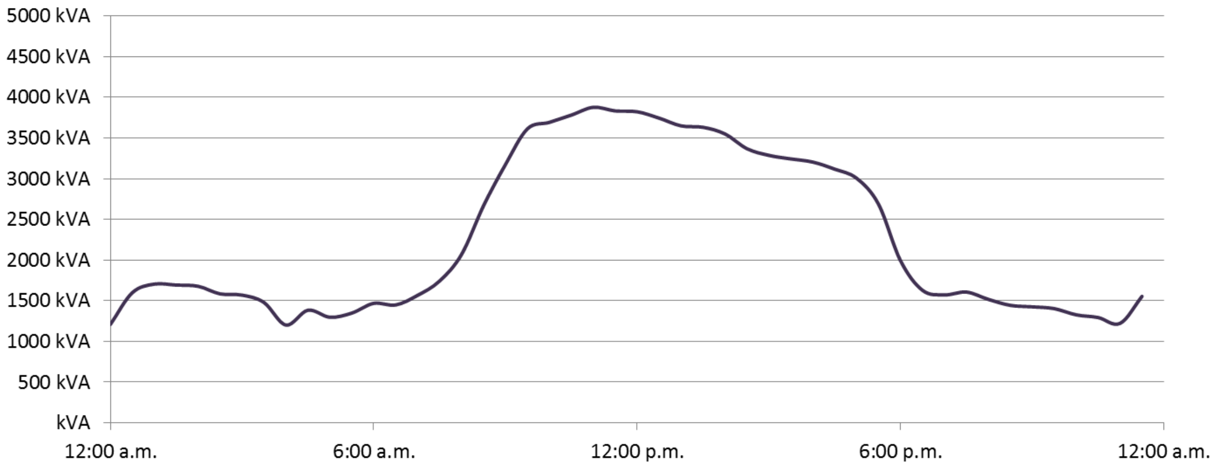

Figure 7: Typical CBD Feeder Daily Load Profile (July, Leven Street CB10)

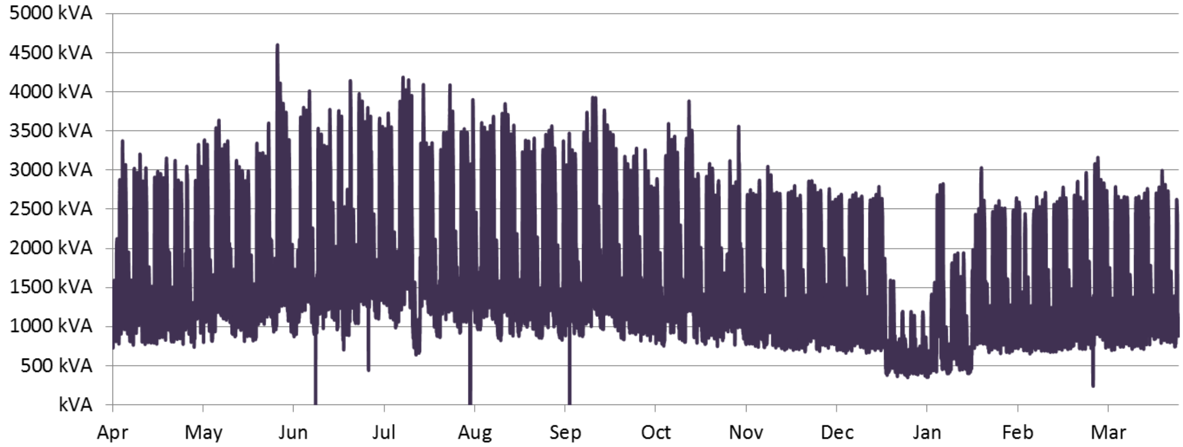

Figure 8: Typical CBD Feeder Yearly Load Profile (Leven Street CB10)

Energy and Demand Characteristics

Key energy and demand figures for the year ending 31 March 2015 are as shown in Table 5.

Table 5: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	273.26 GWh	Variation around minimal growth
Maximum Demand[1]	60.73 MW	Large variation around minimal growth
Load Factor	51%	Reasonably constant
Losses	5.6%	Varying

[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 giving meaningless results due to huge variation between inclusion and exclusion of a particular year (say between 4 years trend or 5 years trend) and longer time periods do not account for recent trends. Growth rates therefore tend to reflect "gut feel" more than anything and accordingly certainty with the growth rates shown in Table 5 is low. Forecasting Demand and Constraints looks at the analysis, trending and forecast of growth for EIL.

2.2. Network Configuration

To supply EIL's 17,333 customers EIL owns and operates two electrically separate networks that are both supplied by a single Grid Exit Point (GXP) at Invercargill. By way of explanation the Bluff network comprises two 11kV feeders supplied by TPCL's zone substation situated just west of Bluff Township. EIL also owns interconnectors to TPCL's Otatara and Seaward Bush 33kV lines that provide alternative supplies to the Leven Street and Southern zone substations respectively.

Bulk Supply Points and Embedded Generation

Invercargill GXP comprises a strong point in the 220kV grid which is tied to Roxburgh and Manapouri power stations and to the North Makarewa GXP. Invercargill is also a major supply node for the Tiwai Point Smelter.

The 33kV supply arrangement at Invercargill comprises an indoor switchboard that is energised by two three-phase 120MVA 220/33kV transformers. There are eleven 33kV feeders each supplied through its own circuit breaker. EIL takes supply from seven of these feeders in normal operation including the two parallel TPCL feeders which supply Bluff. Back up supplies are available from other TPCL feeders and are used from time to time.

EIL owns the segments of 33kV line (but not the circuit breakers or bus) that run within the GXP land area and also accommodates a backup control room for PowerNet's System Control. EIL also owns one of the two 33kV 216⅔Hz ripple injection plants on the west side of the GXP site. The second plant is owned by TPCL with each providing backup capability to the other.

Table 6: EIL Bulk Supply Characteristics

	Voltage	Rating	Firm Rating	Maximum Demand 2014/15	LSI* Coincident Demand 2014/15
Invercargill GXP	220/33kV	210MVA	105MVA	88.20MW (8:00 13/08/2014)	79.72MW (10:30 26/05/2014)
EIL	*(GXP assets shared with TPCL)*			60.73MW (10:00 19/06/2014)	54.79MW (10:30 26/05/2014)

*LSI = Lower South Island

There is no significant generation embedded within EIL's network however a recently installed 6.8MW wind farm at Flat Hill near Bluff is connected at TPCL's Bluff substation from which the Bluff area network takes its supply. 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.

Subtransmission

EIL's subtransmission network is a single electrically connected 33kV network that takes supply from a single GXP at Invercargill and can take emergency supply from the North Makarewa GXP through TPCL's 33kV network as depicted in Figure 9.

Note that EIL's two Bluff 11kV feeders are supplied from TPCL's 33kV subtransmission network. EIL's subtransmission network comprises 1.4km of 33kV line and 26.2km of 33kV cable and has the following characteristics:

- Two points of interconnection with TPCL's 33kV network which provides alternative supplies to Leven Street and Southern zone substations.
- It is almost totally underground except for short lengths of overhead line between Invercargill GXP and Racecourse Road zone substation (about 300m long) and in the middle of the tie between Leven Street zone substation and TPCL's Otatara 33kV feeder.
- It is predominately a ring topology except for Racecourse Road which is a spur.

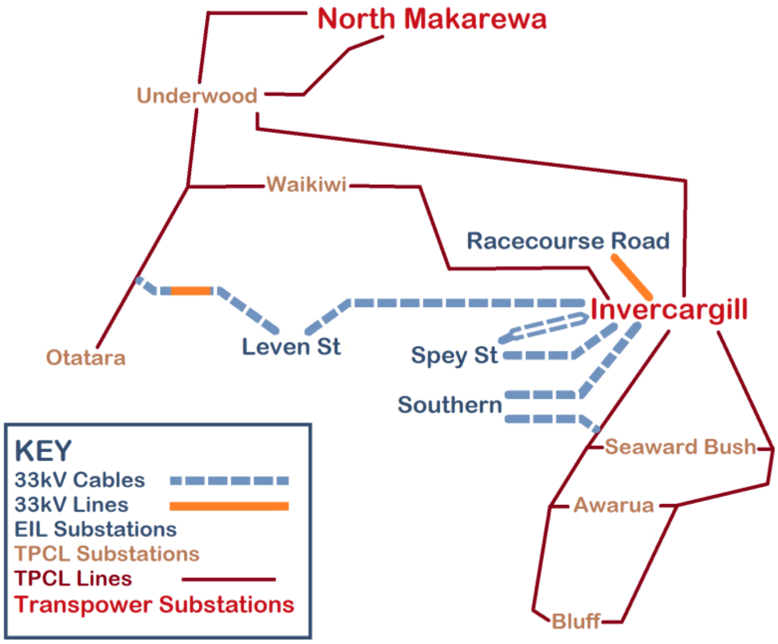

Figure 9: Subtransmission network

Zone Substations

EIL currently owns and operates four zone substations in Invercargill which have either AA or AAA security levels (see Development Criteria for security level definitions) however the Bluff network area also takes an 11kV supply from a TPCL owned substation. Descriptions for EIL's zone substations are given in Table 7.

Table 7: EIL's Zone Substations

Zone Substation	Description
Doon Street (decommissioned)	Doon Street was an urban AAA security substation supplied by two 33kV cables from Invercargill GXP and having a firm rating of 23MVA. This substation has just been decommissioned at the end of the 2014/15 year but remains as a transition point from the 33kV oil filled cables to a new 33kV XLPE extension to Spey Street substation.
Spey Street	Spey Street is a new and modern AAA security urban substation with dual transformers providing a capacity of 72MVA and a firm rating of 36MVA. This substation was constructed as a relocation and replacement for the Doon Street substation which had many assets at end of life and was at risk of third party damage from a potential earthquake. It is a fully indoor site built to blend inconspicuously into its semi-commercial environment. The substation is supplied via a new 33kV XLPE cable and a second cable feeder consisting of the oil filled cables (that previously supplied Doon Street) paralleled and extended with a new 33kV XLPE cable to Spey street. The 11kV switchboard has 12 feeders and is split by two bus coupler circuit breakers with each half located in separate fire rated rooms for added security. The substation supplies mainly residential customers to the East and the Invercargill CBD containing mostly commercial customers to the West.
Leven Street	Leven Street is an AAA security urban substation with dual transformers providing a capacity of 46MVA and a firm rating of 23MVA. It is supplied by a single 33kV XLPE cable from Invercargill GXP but has an alternative 33kV supply from TPCL's Otatara 33kV feeder (which can be supplied from an alternative GXP). This alternative supply achieves the necessary AAA security for the substation however due to its supply being from another GXP the 33kV back-feed cannot be 'normally in service' and therefore a short interruption (i.e. break before make) has to be accepted. The substation supplies a large part of Invercargill's CBD to the East, a heavy industrial area to the West as well as some residential customers to the North and South.
Southern	Southern is an urban AA security substation with a single transformer providing 23MVA capacity. It is supplied by a single 33kV oil filled cable from Invercargill GXP. An alternative 33kV supply is available from TPCL's Seaward Bush 33kV feeder as backup if required. The substation supplies mainly residential customers and a few light industrial customers in the Southern areas of Invercargill.
Racecourse Road	Racecourse Road is an urban AA security substation with a single transformer providing 23MVA capacity. It is supplied by a short 33kV overhead line from Invercargill GXP. The substation supplies predominantly residential areas but also has two metered feeders which supply a small semi-rural area of TPCL's network.
Bluff	EIL's Bluff area is supplied from two metered 11kV feeders from TPCL's Bluff substation to the North West of the town. Two other feeders are used as a supply to rural customers North of Bluff and as a connection point for Southern Generation's Flat Hill Windfarm. The Bluff substation is an AAA security site with two transformers providing a capacity of 26MVA and a firm rating of 13MVA. Bluff substation is supplied from two 33kV overhead lines from Invercargill GXP via TPCL's Colyer road substation. The size of the total load on the Bluff substation is technically only large enough to justify AA security but due to the lack of 11kV backup capacity it was more economic to provide AAA security at the site which is a great benefit to EIL.

Distribution Network

The 11kV distribution network is heavily meshed throughout the entire Invercargill area, with almost all distribution transformers being able to be supplied by two separate 11kV supplies. In the CBD most supplies to each transformer are protected by 'Solkor' unit protection.

Distribution in Bluff is mainly meshed except at feeder extremities.

The 11kV distribution network construction is as follows:

- All underground cable within the Invercargill CBD. Cable type (PILC or XLPE) depends on date of original installation or of repairs and renewals.
- Suburban areas of Invercargill are either XLPE cable or overhead line. A gradual overhead to underground (OHUG) program has been implemented over several decades leaving less than 10km of overhead construction left.
- Bluff is almost totally overhead construction due to the shallow soil over rock substrata making undergrounding difficult. Originally the Bluff area was operated at 3.3kV distribution with conversion to 11kV occurring after EIL took over the assets.

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

Distribution Substations

Just as zone substation transformers form the interface between the subtransmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from a few remaining pole-mounted transformers to 3-phase 1,000kVA ground-mounted transformers supplied via circuit breaker ring main units and may include remote indication and control. These larger substations typically supply CBD customers or special customers, like the Stadium Southland event centre. There are a few underground sites located in vaults below pavements or road centre-plots, particularly in the CBD where land for ground mounted equipment was not available. Table 13 shows distribution transformer numbers by rating.

Each distribution transformer has medium voltage (MV) protection generally provided by fuses but some larger units by circuit breakers controlled by basic overcurrent and earth fault relays. This is generally applied as individual protection for each site though occasionally group protection is used where a single fuse is located at the take-off from the main feeder cable with up to five downstream units.

Low voltage protection is by DIN[2] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

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

Low Voltage Network

The 230/400V Low Voltage (LV) network almost totally overlays the 11kV distribution network and is present on virtually every street. The coverage of each individual distribution transformer tends to be limited by volt-drop to about a 200m radius.

The LV network 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.

All of the Invercargill CBD and most of the suburban area reticulation is underground cable; mostly PVC with some older PILC cables. A couple of areas have overhead line remaining.

Bluff has overhead construction with underbuilt LV reticulation on most 11kV poles. Some undergrounding has occurred in a few locations using XPLE cable.

Customer Connection Assets

EIL has 17,333 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 EIL 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 and changes over the year are shown in Table 8.

Table 8: Classes of Customer Connections

	Small (≤ 20kVA)				Medium (21 – 99kVA)			Large (≥100kVA)			
	8kVA 1ph	10% Fixed Option	20kVA 1ph	15kVA 3ph	30kVA 3ph	50kVA 3ph	75kVA 3ph	100kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	Total
Apr-14	343	4,139	11,202	75	708	378	129	71	53	125	**17,223**
May-14	343	4,225	11,208	75	708	379	129	71	53	125	**17,316**
Jun-14	344	4,203	11,225	75	708	379	129	71	52	126	**17,312**
Jul-14	343	4,205	11,243	76	706	379	129	71	52	126	**17,330**
Aug-14	344	4,176	11,262	77	708	380	128	71	52	126	**17,324**
Sep-14	348	4,227	11,206	77	706	378	129	70	52	126	**17,319**
Oct-14	352	4,216	11,220	77	708	377	128	70	52	126	**17,326**
Nov-14	352	4,245	11,195	79	706	376	127	70	52	126	**17,328**
Dec-14	351	4,250	11,206	79	705	377	127	70	53	126	**17,344**
Jan-15	349	4,472	10,970	79	702	375	127	69	53	126	**17,322**
Feb-15	346	4,537	10,911	79	701	372	127	69	53	126	**17,321**
Mar-15	342	4,552	10,910	78	700	376	127	69	53	126	**17,333**

In most cases the fuse forms the demarcation point between EIL'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.

EIL has a range of other assets to provide control or other auxiliary functions as described in Table 9.

Table 9: EIL's Other Assets

Load Control Assets	
Ripple Injection Plant and Receivers	EIL currently owns and operates a 33kV 216⅔Hz 125kVA ripple injection plant at Invercargill. Ripple relays at 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 injection plant is backed up from the adjacent TPCL plant and vice versa.
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.
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. SOLKOR differential protection is also used extensively on 11kV cables in the Invercargill CBD. 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 EIL's SCADA master station is located at PowerNet's System Control centre at the Findlay Road GXP, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.
Communication Media	EIL currently owns and operates a multicore copper network between zone substations, CBD distribution substations and the SCADA master station at System Control from where control commands may be issued. Data-radio links are also in service linking the System Control Data-radio to the Doon Street, Racecourse Road, and Southern zone substations and the Gore Street circuit breaker in Bluff.
Remote	Leven Street zone substation has one Harris D20M multiple rack RTU communicating

Terminal Units	with DNP3.0 protocol over 9600 baud Modem. Kingfisher RTUs are located at each of the Racecourse Road, Doon Street and Southern zone substations. Another Kingfisher RTU is located at a CBD distribution substation and there is also a Nulec controller for a field circuit breaker acting as an Intelligent Electronic Device (IED) in Bluff. The above RTUs all communicate with DNP3.0 protocol over 9600 baud Modem. There are eight GPT mini RTUs located in other distribution substations in the CBD communicating with HDLC protocol over 1200 baud modem.
Other Assets	
Generation	EIL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 450kW, 350kW and at 220kW. There are no stand-by generators owned or able to be utilised by EIL.
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 EIL does not own any power factor correction assets.
Mobile Substations	EIL can utilise a TPCL owned trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections though it is unlikely to be required due to the excellent backup capability of the 11kV network.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3. Network Asset Details

The remainder of this section summarises key asset information that contributes to the long term lifecycle planning for EIL's network.

Subtransmission Network

Basic details for EIL's subtransmission circuits are shown in Table 10. All circuits are 33kV and operate within their respective ratings.

Table 10: Subtransmission Circuit Details

Location	Type	Length	Manufactured	Remaining Life	Condition
Invercargill GXP to Southern	Oil Cable	4.7 km	1968	22yrs	Good, only lightly loaded.
Invercargill GXP to Doon Street T1	Oil Cable	3.5 km	1970	24yrs	Good, moderately loaded.
Invercargill 2872 to Doon Street T2	Oil Cable	3.5 km	1975	29yrs	Good, moderately loaded.
Invercargill GXP to Racecourse Road	O/H Line	0.3 km	1975	19yrs	Good, short cross country, concrete poles.
Invercargill GXP to Leven Street	XLPE Cable	5.3 km	1983	14yrs	Good, lightly loaded.
Seaward Bush Line to Southern	XLPE Cable	1.4 km	1999	28yrs	Good, not normally loaded.
Otatara Line to Leven Street	XLPE Cable O/H Line	3.7 km 1.1 km	2000	29yrs 44yrs	Good, not normally loaded.

Location	Type	Length	Manufactured	Remaining Life	Condition
Invercargill GXP to Spey Street	XLPE Cable	4.1 km	2015	44yrs	As new, lightly loaded.

Subtransmission Cables

EIL has three oil filled cables taking supply from the Invercargill GXP substation, the oldest of which has approximately 22 years expected life remaining so should be in sound condition. One of the oil cables cable supplies Southern substation and operates up to about half of its rating. The other two cables previously supplied Doon Street and were similarly operated up to about half of their capacity. However these cables have now been paralleled and extended with XLPE cable to supply Spey Street which has reduced typical loading to low levels.

There are some concerns with the rating of the cables due to poor thermal resistivity backfill used and over the last year temperature and thermal resistivity transducers have been installed on the cables to better understand their in service capacity. This issue will be better understood as data accumulates with operation of the cables over time. There is also some concern over the integrity of the cable joints which have been found to be trending toward premature failure by other distribution companies. It is unknown whether similar issues exist around EIL's oil filled cables and with no local expertise, options for condition assessment are being considered. It is noted that any invasive exploration into the cables is likely to be very expensive and may be uneconomic to investigate to get any definitive answers. The risk of failure has largely been mitigated by the oil cables parallel operation as part of one feeder while a new XLPE cable operates as the second feeder supplying Spey Street to provide AAA security to the site.

The other cables are XLPE cables which are lightly loaded and in good condition. Some of these are unloaded cables used occasionally for backup. 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 10 shows the commissioning year and installed length for EIL's subtransmission cables (as of the end of March 2015).

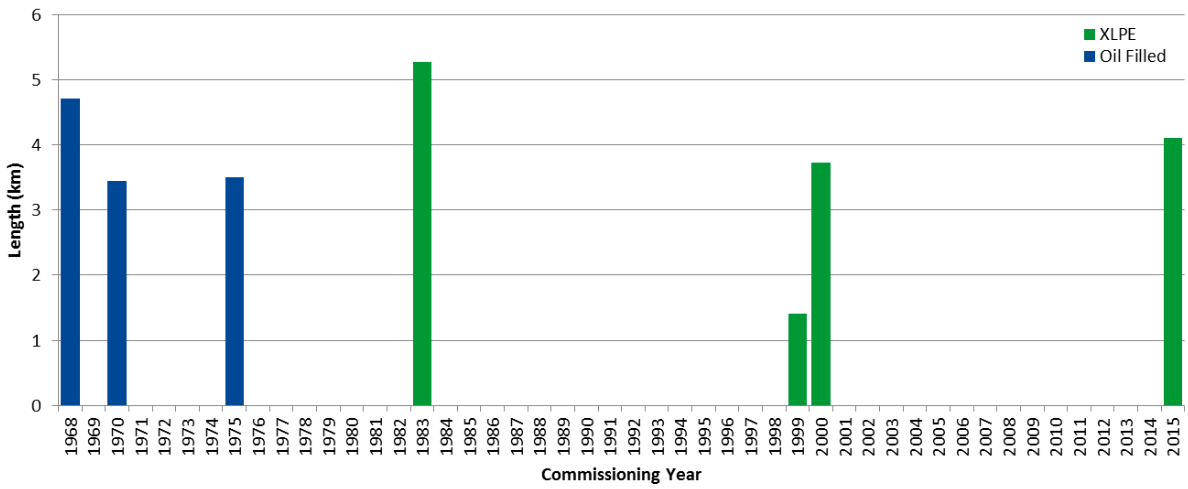

Figure 10: Subtransmission Cables

Zone Substations

Subtransmission Voltage Switchgear

The 33kV switchboard at Leven Street Substation is indoor, relatively modern and in good condition. At Southern substation EIL's oldest circuit breaker is an outdoor type and is at end of life while a second outdoor circuit breaker has had a service life of 32 years but has some rusting due to the harsh coastal environment in Bluff from where it was relocated. Two relatively young circuit breakers are located at Doon Street but have now been removed from service.

Outdoor equipment at Southern Substation has been damaged by vandalism. Protective barriers have been installed around critical equipment however without fully enclosing equipment there is remaining risk of damage insulators from thrown stones.

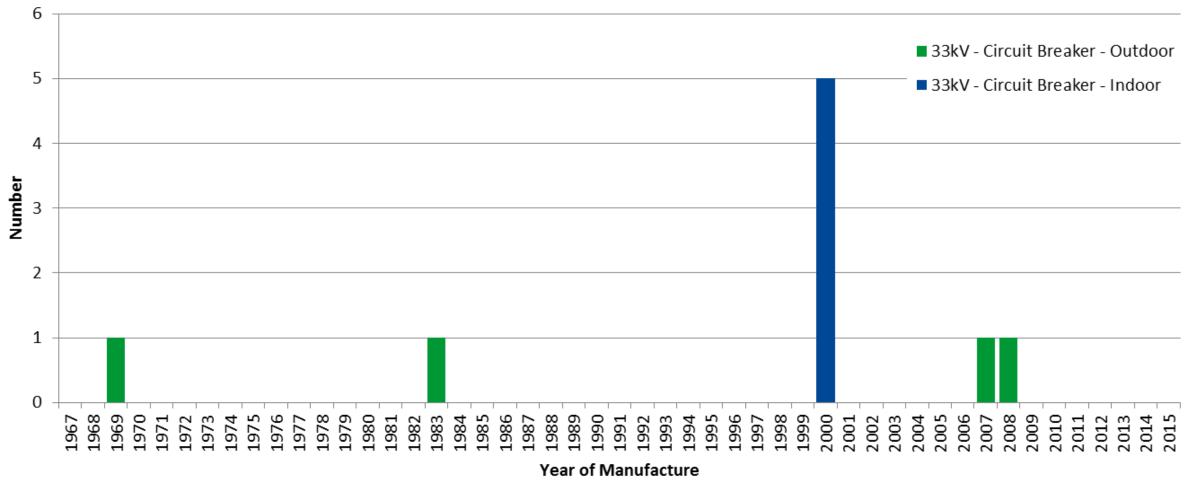

Figure 11: Subtransmission Voltage Circuit Breakers

Power Transformers

The Power Transformers at EIL's zone substations were all rated to supply load up to 23MVA with forced cooling, based on an ambient temperature of 5°C as peak load in EIL generally occurs at the coldest times when heating requirements are greatest.

One of the two units installed at Doon Street unexpectedly failed in service despite monitoring condition with Dissolved Gas Analysis. A new 36MVA maximum rated transformer was installed as replacement for the failed unit but has now been relocated to the Spey Street substation with a second new 36MVA transformer in parallel as part of a AAA security substation supply. The second 23MVA Doon Street unit (T1) was removed from service last year and is presently being stored in situ.

Furan analysis is showing the Doon Street remaining unit's paper insulation to be advanced in age but not inconsistent with its service life to date. It is intended to be put back into service to utilise remaining life as a second transformer at Southern substation in 2019/20. The existing Southern substation transformer has six years of a standard 55 year life remaining however Furan analysis suggests the insulation is in sufficient condition to provide an extended life.

The transformer at Racecourse Road has a remaining 14 years of standard life but has significant rusting. It will be refurbished in 2017/18 at which time further assessment of condition can be made. The other two transformers that are beyond half of their expected life are the Southern substations unit and Leven Streets T1 unit and will be refurbished in 2020/21 and 2021/22 respectively.

Due to this condition assessment and the age of the units there are no power transformer replacements expected within the next 10 years.

Table 11: Power Transformers

Transformer Location	Rating	Installed	Remaining Life
Spey Street T1	18/36 MVA	2015	54
Spey Street T2	18/36 MVA	2012	51
Doon Street T1	11.5/23 MVA	1970	9
Leven Street T1	11.5/23 MVA	1983	22
Leven Street T2	11.5/23 MVA	2002	41
Southern T1	11.5/23 MVA	1967	6
Racecourse Road T1	11.5/23 MVA	1975	14

Distribution Voltage Switchgear

The 11kV circuit breakers installed at EIL's zone substations with their year of manufacture are shown in Figure 12 (as of the end of March 2015).

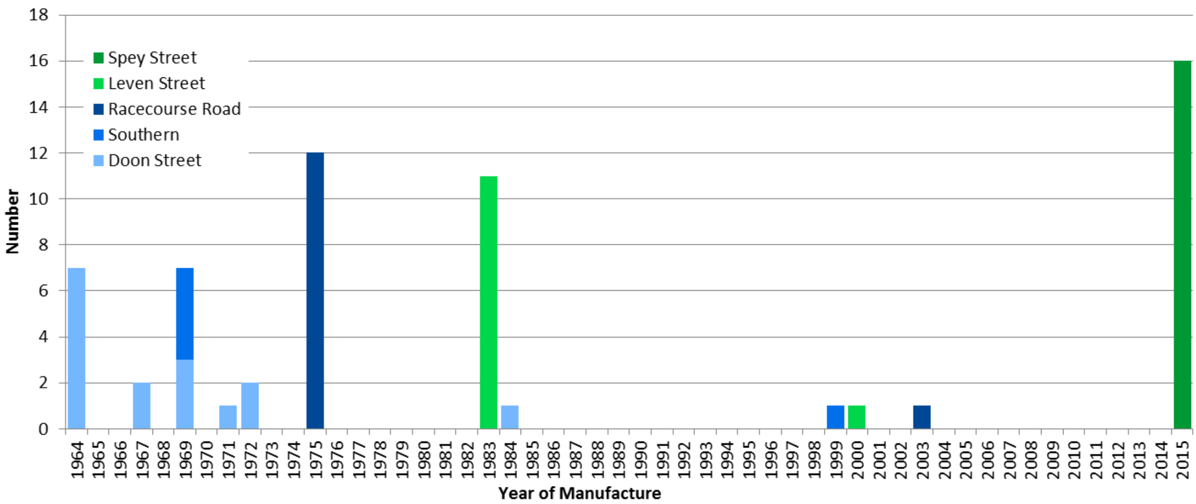

Figure 12: Circuit Breakers at Zone Substations

EIL's oldest switchgear was decommissioned at Doon Street in March 2016. The first seven circuit breakers were installed in 1964 and augmented with a further eight circuit breakers with the latest a second incomer added in 1984. The switchboard has been left in situ until the demolition of the building in 2019/20 and its circuit breakers or parts may be utilised as spares.

The Southern switchboard has reached end of standard life having been installed in 1969. Its replacement has been deferred until 2019/20 as part of the overall substation replacements and upgrades project. Condition monitoring is being used to manage risk associated with the continued operation of the aged switchgear. One of the circuit breakers was recently found to have elevated partial discharge levels indicating the beginning of insulation breakdown. This circuit breaker has now been removed from service and the load transferred onto another circuit breaker which was previously supplying only the local service transformer (substation supply). A new incomer circuit breaker was installed in 1999 to enable a spare transformer to be brought in and put into service relatively quickly as part of contingency planning.

The Racecourse Road switchboard was installed in 1975 and is due for its fixed time replacement in 2020/21. Again a new incomer circuit breaker was installed in 2003 to enable a spare transformer to be brought in and put into service relatively quickly as part of contingency planning. There are no issues noted with any of the switchboards circuit breakers.

The 11kV switchboard at Leven Street was installed in 1983 with an additional incomer installed in 2000 when the second transformer was installed. There are no issues noted with any of the switchboards circuit breakers.

DC Power Supplies

As DC batteries are essential to the safe operation of protection devices, regular checks are carried out and each battery is replaced prior to the manufacturer's recommended life of ten years. No batteries are more than seven years old.

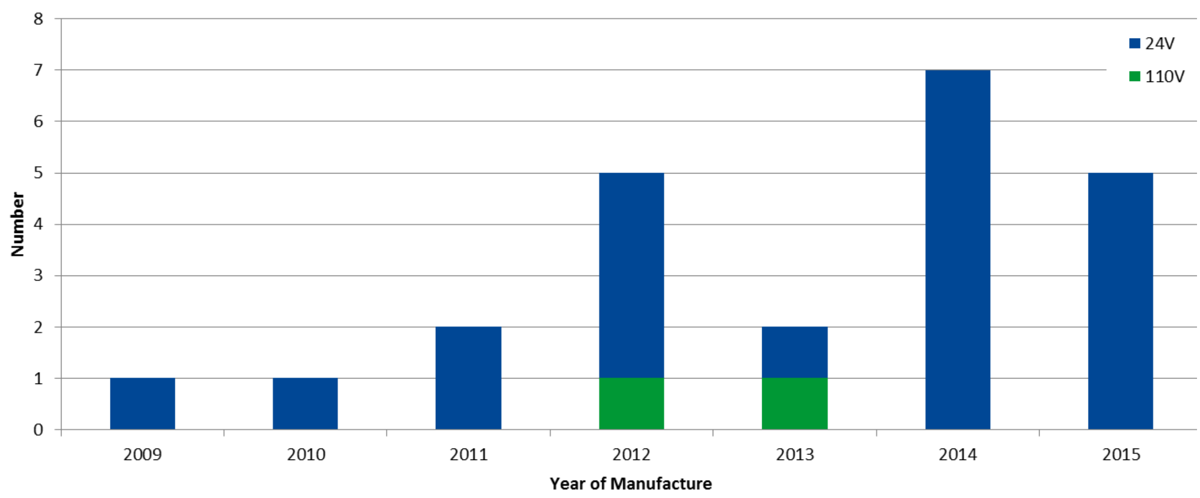

Figure 13: DC Batteries

Tap Changer Controls

Six voltage regulating relays are in operation having been installed with their associated transformers and are in good condition. Replacements will also coincide with transformer replacements when due, or in line with projects such as the upgrades planned at Southern substation in 2019/20. Unexpected failures may require replacement with the modern voltage regulating relay standardised solution based on an SEL controller, which has been installed for both new Spey Street transformers.

Distribution Network

EIL's Distribution network has a total length of 182km to supply its 17,333 customers giving an overall customer density of 95.2 customers per kilometre. The proportions that are overhead or underground and the customer count and density is shown in Table 12 on a per substation basis.

Table 12: Distribution network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street*	-	9.9	125	12.6/km
Doon Street*	-	44.4	5,493	123.7/km
Leven Street	4.9	30.7	2,217	62.3/km
Racecourse Road	3.1	24.6	2,899	104.7/km
Southern	1.6	44.8	5,556	119.7/km
Bluff – EIL feeders	13.2	4.7	1,043	58.3/km
Total/average	22.9	159.1	17,333	95.2/km

*As of end of March 2015; load being transitioned from Doon Street to Spey Street

Overhead

EIL's overhead distribution network uses a mix of concrete and wood poles as shown in Figure 14 which displays estimated commissioning year. Most of the Invercargill network has been undergrounded as part of an extensive undergrounding programme with only a few streets remaining as overhead in industrial areas. The Bluff area has remained as overhead network as Bluff's rocky sub-surface makes undergrounding difficult and expensive.

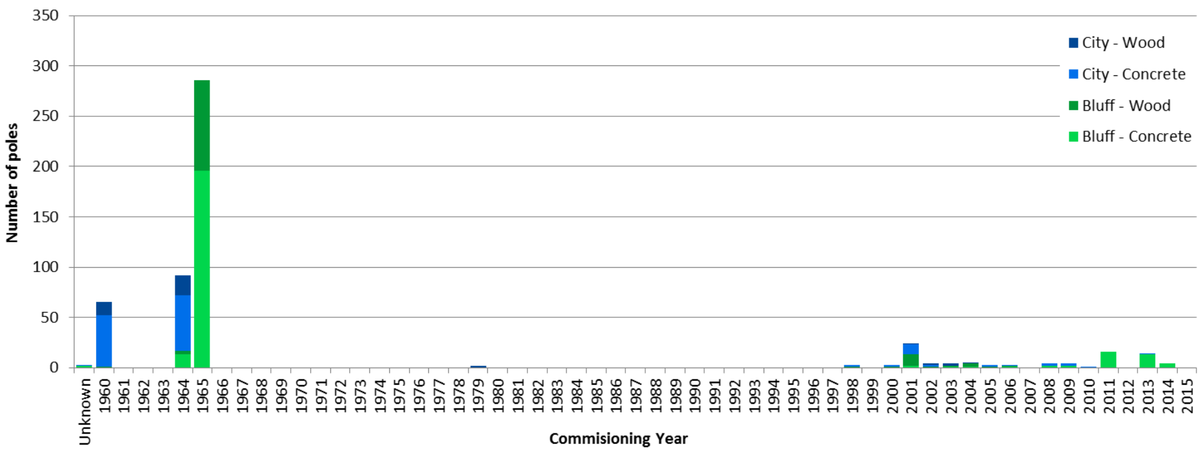

Figure 14: Distribution Poles

In theory for wooden poles, all lines built prior to 1970 should be replaced by the end of 2015 however five yearly condition assessment surveying is done on all distribution lines with remedial repairs or renewal planned based on information obtained.

Maintenance of poles remaining in the Invercargill network area was deferred due to planned undergrounding of the Bond Street industrial area. This area will now remain as overhead construction therefore a slight focus in this area will now be required to catch up on this deferred maintenance.

The commissioning year for the distribution line conductors is displayed in Figure 15. Conductor is generally replaced based on condition as identified through routine inspection.

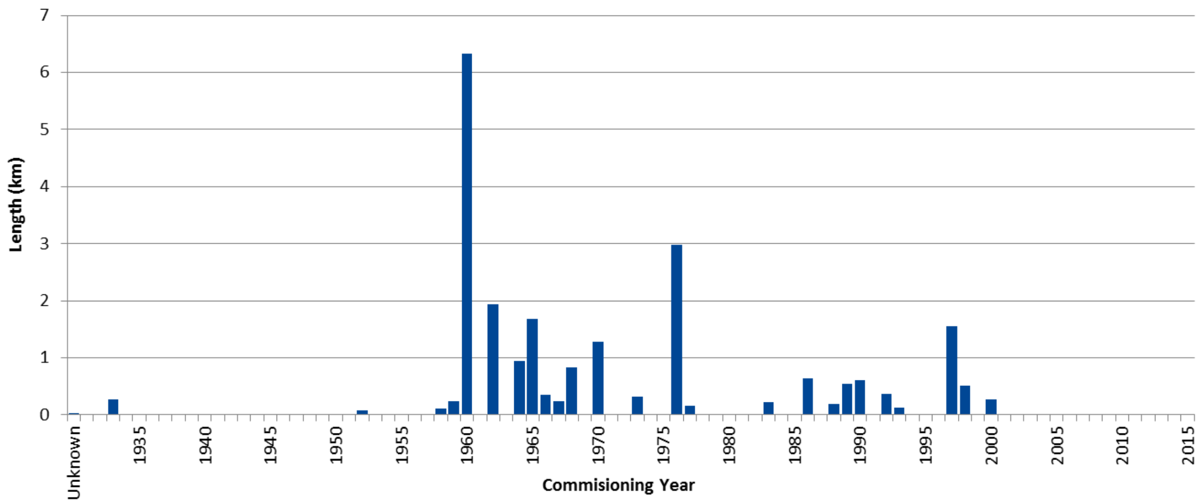

Figure 15: MV Line Conductors

EIL has two 11kV pole mount field circuit breakers and an enclosed load break switch in service on the Bluff area network, located respectively at Gore, Bann and Palmer Streets. This switchgear was installed as part of network automation and reliability enhancements and is detailed as follows;

- The Gore Street circuit breaker is a Nulec N24 reclosing circuit breaker manufactured in 1997. It was relocated in 2015 to a more optimal location. It has minor signs of aging but is in reasonable condition.
- The Bann Street circuit breaker is a Nova 15 reclosing circuit breaker manufactured in 2006 and kept in spares before being installed in 2015. It is in as new condition.
- The Palmer Street load break switch is an Entec solid insulation vacuum breaking switch and was installed new in 2015.

Figure 16 shows numbers of air break switches by commissioning year. Only twelve ABSs remain on the Invercargill network with most having been removed as part of the undergrounding programme while 18 are in service in Bluff.

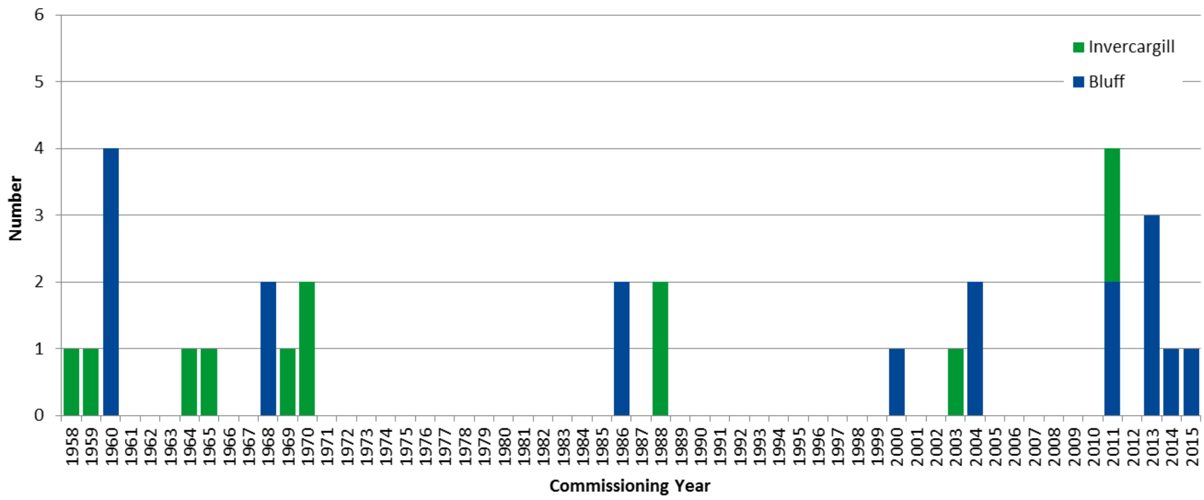

Figure 16: Air Break Switches

Most of the drop-out fuses on the network have been removed due to the undergrounding of services in the city, with a relatively small number remaining, mainly in Bluff. They are most often used where a transformer is supplied from overhead lines.

Underground

Distribution cables were installed gradually as replacement for overhead lines on the Invercargill network as part of an ongoing undergrounding programme. Some cables have been installed in Bluff but the Bluff network area remains mostly overhead as the rocky subsurface makes undergrounding service difficult. Figure 17 show the lengths of cables on EIL's network by commissioning year.

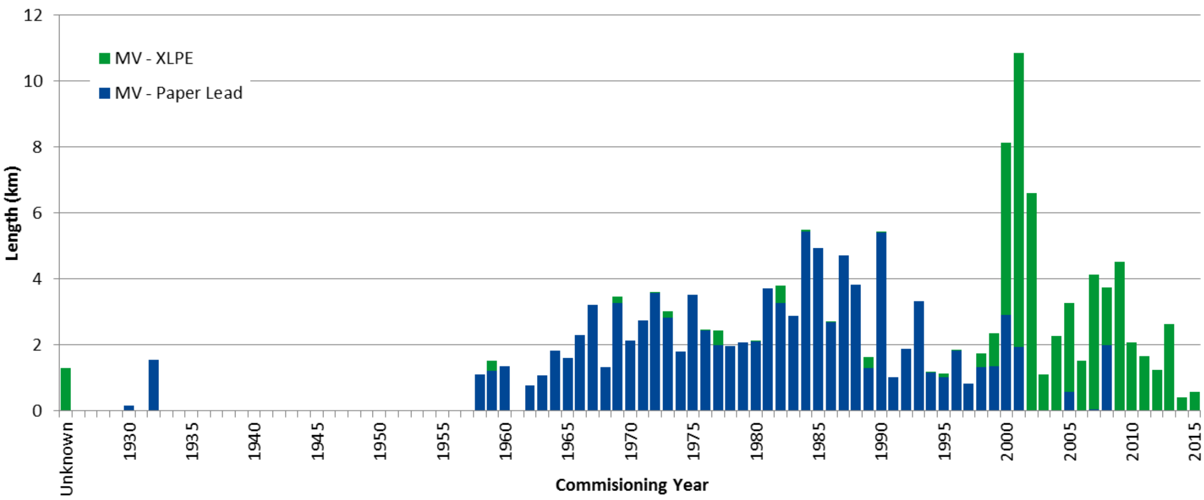

Figure 17: MV Cables

Paper lead cables were predominantly used up to about 2000 after which XLPE was the preferred cable type due to the ease of installation and working with XLPE cables. Actual practical life for any cable is likely to be greater than the standard life and a programme of assessing and monitoring of condition will be developed and used in planning as the oldest cables begin to reach end of life. Most cables are lightly loaded and in sound condition however there have been termination and joint failures.

Distribution Substations

Transformers

Table 13 shows the numbers of distribution transformers by size on EIL's network and their age profile is displayed in Figure 18. Transformers larger than 100kVA are now installed at ground level and after the extensive undergrounding programme only a few pole mounted transformers remains. Transformers found to be in poor condition after five yearly inspections may be replaced with units removed from service refurbished for reuse if economic. Many ground mounted units are enclosed and the condition of these transformers is good due to reduced exposure.

Table 13: Number of distribution substations

Phases	Rating	Pole Mount	Ground Mount
1 phase:	up to 15kVA	2	1
	30kVA	1	-
3 phase:	up to 15kVA	-	1
	30kVA	-	3
	50kVA	2	2
	75kVA		1
	100kVA	3	17
	200kVA	4	63
	300kVA	1	249
	500kVA	-	59
	750kVA	-	31
	1,000kVA	-	8
	Total	**13**	**435**

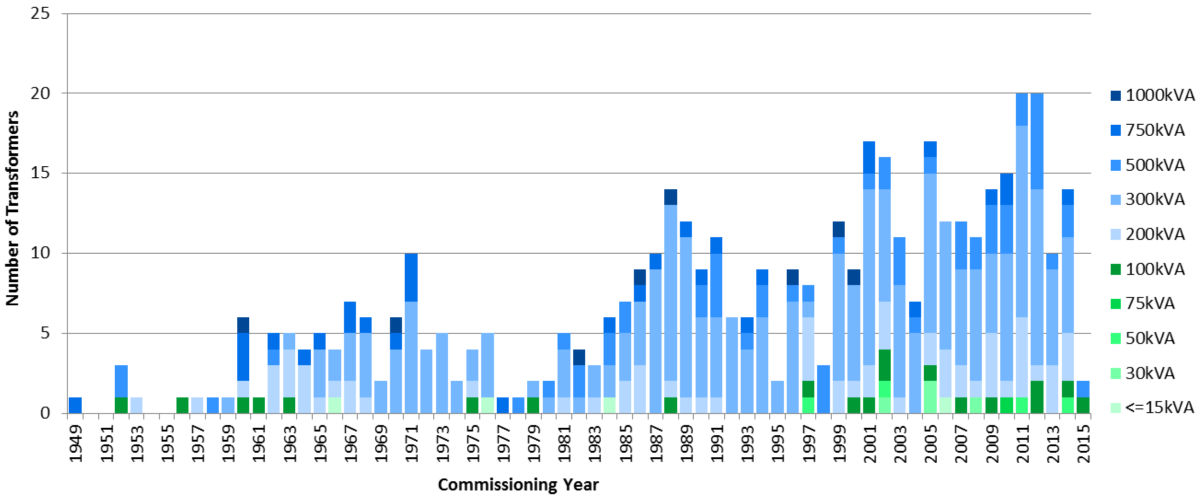

Figure 18: Distribution Transformers

Switchgear

Figure 19 shows the circuit breakers installed at EIL's distribution substations which are located within the Invercargill CBD. Most of these circuit breakers work with SOLKOR cable differential protection to provide additional supply security in the CBD while some provide protection for transformers. Most of this switchgear is well advanced in age but will be replaced over the next three years as part of the programme to remove the underground substations where these circuit breakers are located. Remaining circuit breakers will be replaced in following years.

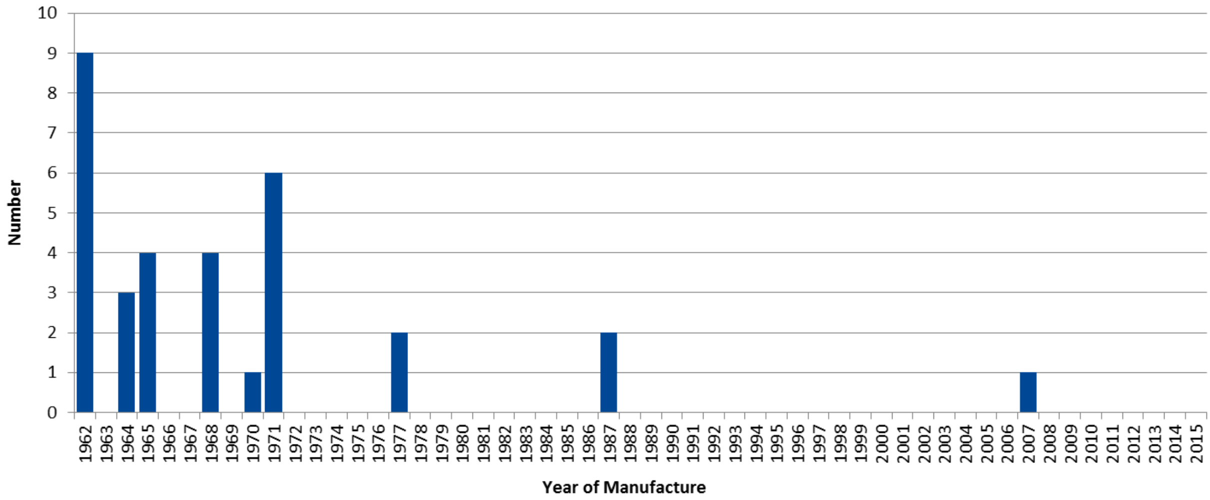

Figure 19: Field Circuit Breakers at Distribution Voltage

The age profile of ring main units (RMUs) is displayed in Figure 20 which shows a number of units have reached their standard life of 45 years (although some ages have been estimated).

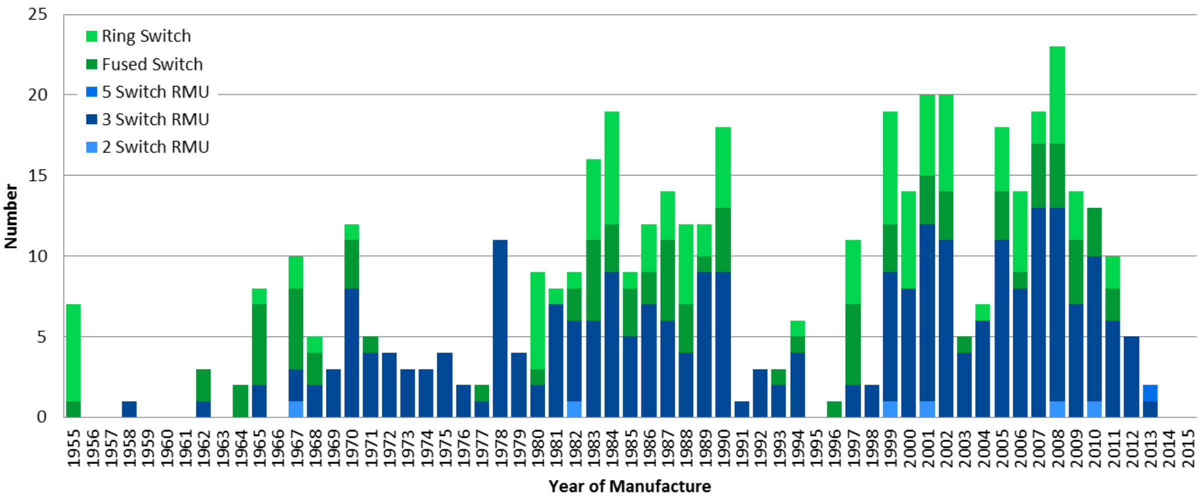

Figure 20: Ring Main Units

Some equipment has had operating restrictions placed on them to manage hazards associated with oil filled switchgear as identified by incidents occurring in the wider industry. Solutions are being investigated to allow safe operation of the equipment to alleviate issues with working around the operating restrictions. Some outdoor units have also developed rusting issues that may lead to early replacement of affected switchgear. The oldest switchgear will be replaced as part of the programme to remove the underground substations where these RMUs are located and other units will be replaced as required based on condition.

Remote Terminal Units

The early GPT mini RTU's were installed in 1995-98 to automate circuit breakers at distribution substations in the CBD. These eight units have continued to provide patchy service and are now at end of life. Replacements are progressing with removal of the underground substations where most of these RTUs are located.

A Harris D20M RTU installed in 2000 at Leven Street zone substation is at end of life and is currently being replaced with a modern SEL solution interfacing with existing I/O.

Three Kingfisher CP-11 RTUs were installed in 2004 at Doon Street, Southern and Racecourse Road zone substations and their replacements are scheduled for 2019/20. The Doon Street RTU has been retained to provide indications for the oil filled cables after the decommissioning of the power transformers, 11kV switchboard and associated auxiliary equipment. Another smaller Kingfisher PC-1 RTU was installed in 2004 at a distribution substation in the CBD and will be replaced at end of life.

Two modern SEL RTUs were recently installed at the new Spey Street zone substation for secure remote indications and control for each half of the AAA security substation.

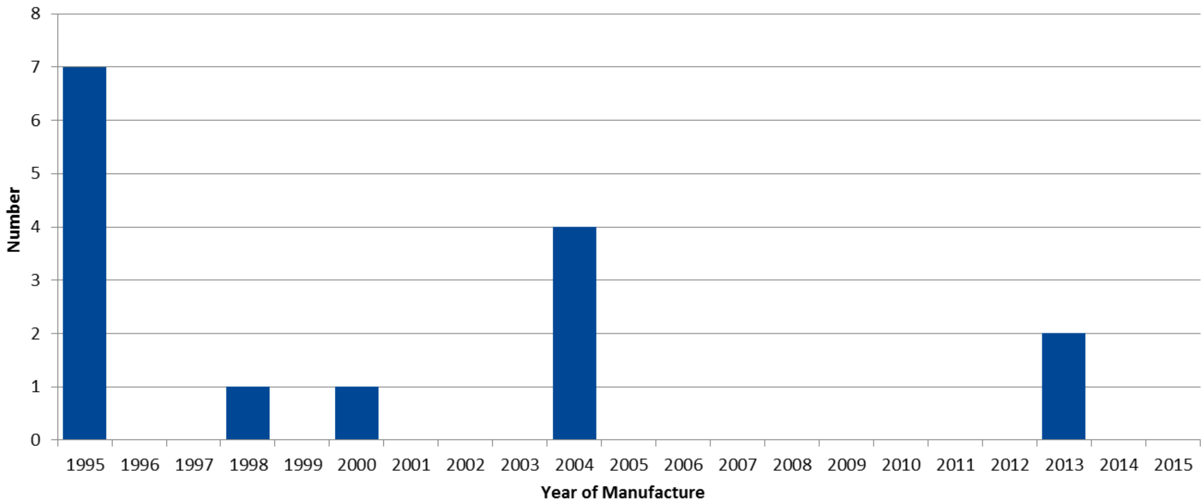

Figure 21: Remote Terminal Unit Assets

Metering

EIL has 'Time Of Use' (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these is shown in Figure 22.

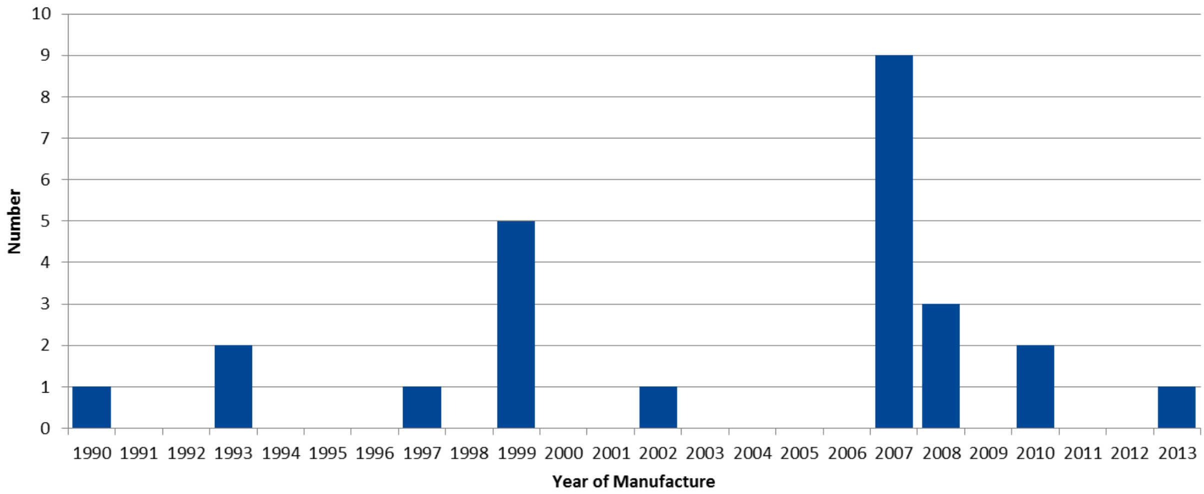

Figure 22: Metering Assets

LV Network

EIL's LV (400/230V) network has a total length of 451.5km to supply its 17,333 customers giving an overall customer density of 38.4 customers per kilometre. The proportions of overhead and underground network and the customer count and density is shown on a per substation basis in Table 14.

Table 14: LV network per substation

Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Spey Street*	-	27.9	125	4.5/km
Doon Street*	-	112.4	5,493	48.9/km
Leven Street	3.3	55.6	2,217	37.6/km
Racecourse Road	0.8	75.0	2,899	38.2/km
Southern	1.4	147.3	5,556	37.4/km
Bluff – EIL feeders	24.5	3.3	1,043	37.5/km
Total/average	30.0	421.5	17,333	38.4/km

*As of end of March 2015; load being transitioned from Doon Street to Spey Street

Overhead

The EIL's age profiles for overhead LV conductors and for poles are shown respectively in Figure 23 and Figure 24. Almost all LV lines in the city have gradually disappeared from the Invercargill network as the services have been undergrounded with less than 6km line length remaining. Most of the LV line length is on the Bluff area network where undergrounding is difficult due to the rocky subsurface.

Poles are renewed as required based on condition as identified during the regular inspections of the network. A significant number of LV pole replacements have been completed recently as a result of these inspections. Overhead LV conductor is also replaced on condition. New overhead line is installed as ABC (Aerial Bundled Conductor) which does not require cross arms and insulators and has PVC insulation improving line safety.

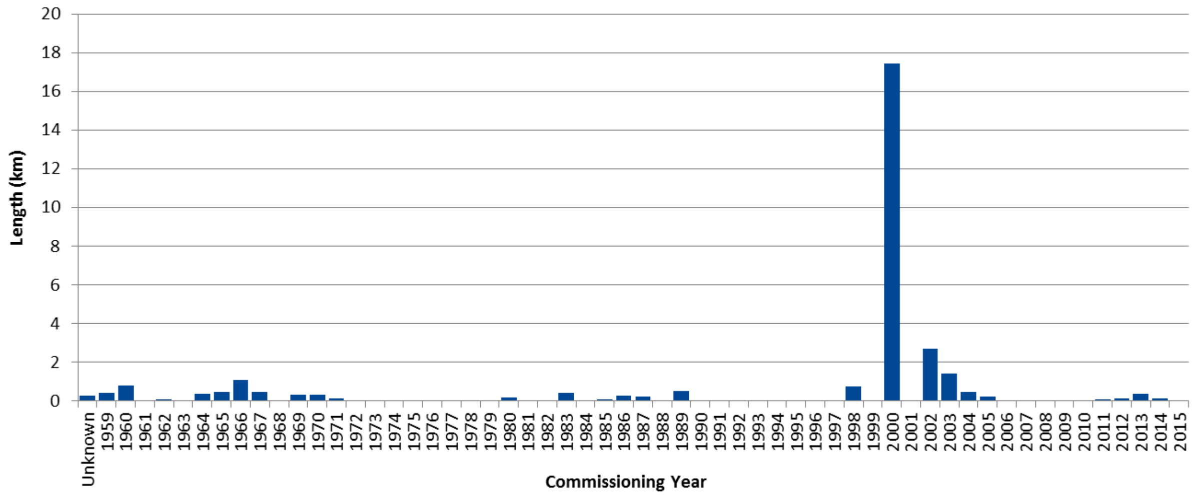

Figure 23: LV Lines

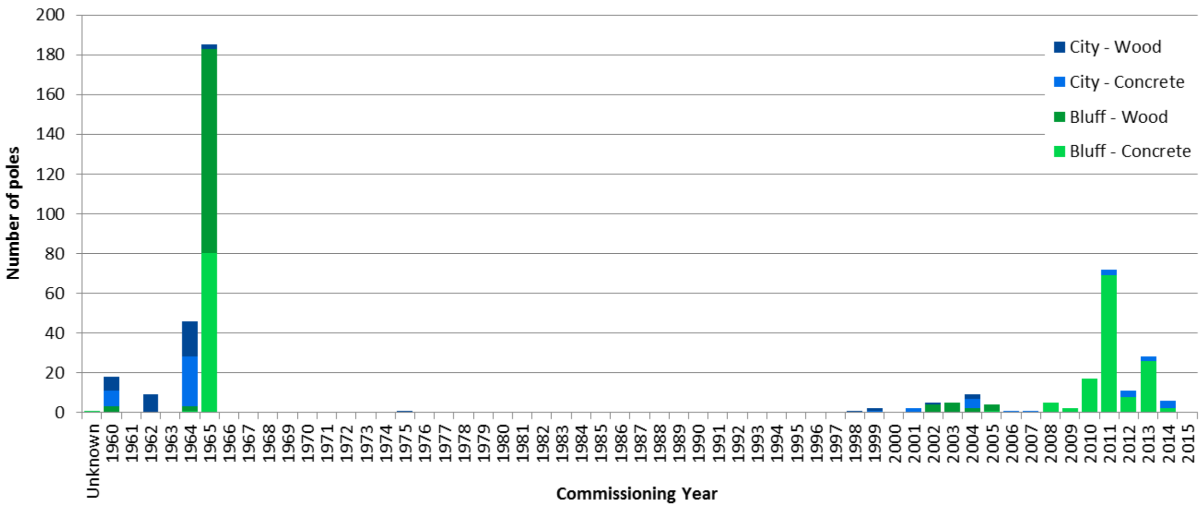

Figure 24: LV Poles

Underground

The LV cable commissioning year profile is shown in Figure 25 and highlights that based on age a number of assets should be renewed. In practice cables are left in service until performance deteriorates impacting on service levels.

Several 400V cables installed in the early 1970s are now reaching capacity due to in-build and greater demand per household. This is typically seen as an increase in voltage complaints received due to excessive volt drop during periods of peak loading. Smart meters being installed at customer's premises will allow much improved capability to monitor voltage quality and proactively address issues before they are noted by customers.

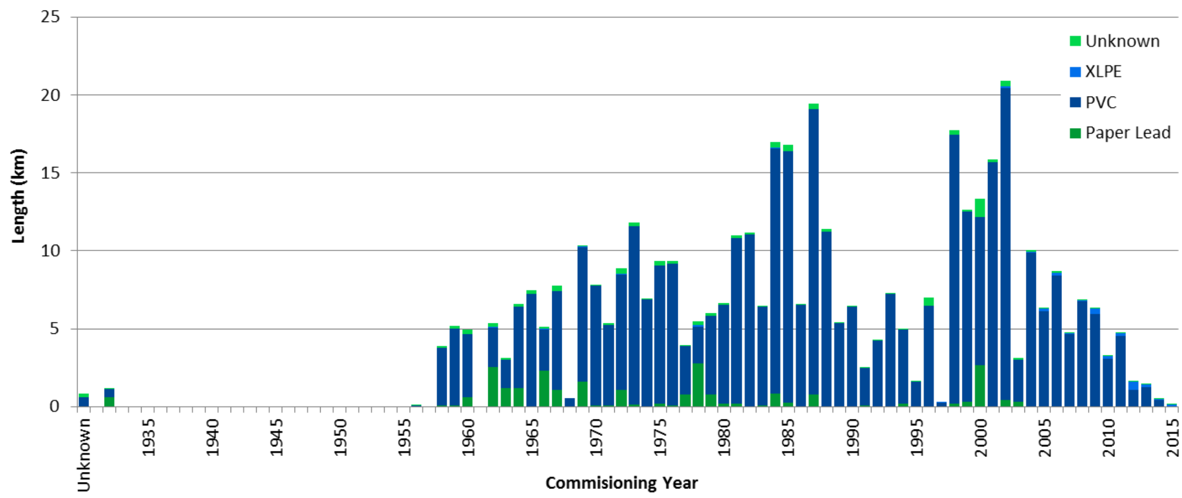

Figure 25: LV Cables

Other Assets

SCADA and Communications

The initial SCADA master station was commissioned in 1999 with a further upgrade of the Server PC's in 2005. These SCADA servers have now reached end of standard life. The software has been developed with the latest version being implemented with the servers in 2005. The communications links have also been upgraded recently and the equipment is still in as-new condition.

Bulk Supply Assets

The company owns an injection plant at Invercargill GXP which was commissioned in 1989, with all plant enclosed within the building. This provides protection from the elements and therefore an extended life is expected for the non-electronic components. The electronic components continue to provide good service with the power supply unit upgraded in 2005, after failures at other sites. While the plant has reached end of ODV standard life the condition and minor replacements mean the expected remaining life of this plant is at least 3 years by which time the injection plant will be made redundant with the installation of smart meters.

Mobile Plant/ Load Correction/ Generation

EIL does not own any mobile substations, power factor correction plant, mobile generation or standby generation plant however PowerNet own three mobile diesel generators rated at 500kW, 350kW and 275kW which EIL utilise to maintain supply to customers when assets are removed from service for maintenance.

3. Service Levels

This section describes how EIL sets its various service levels according to the safety, viability, quality, compliance and price objectives that are most important to stakeholders (see Drivers and Constraints). It details how well EIL 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 EIL'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 EIL 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. It also appears that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs although other research indicates that flicker is probably noticed more often than it is actually a problem.

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

- Limited substitutability between service levels e.g. customers prefer EIL 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. For example Invercargill and North Makarewa GXP's are more secure, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point..

Primary Customer Service Levels

Surveyed customers have indicated that they value continuity and then restoration most highly; therefore EIL's primary service levels are continuity and restoration. To measure performance in this area EIL 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 EIL. EIL's projections for these measures over the next ten year period ending 31 March 2026 are shown 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.

These forecasts are average values around which significant variation can be expected due to the random occurrence of a low number of faults and weather impacts. EIL's network reliability has been extremely good due to the underground network in Invercargill and forecasts are for a slight improvement in future years.

Table 15: EIL Reliability Projections

Measure	Class	2016/17	2017/18	2018/19	2019/20	2020/21	…	2025/26
SAIDI	B (Planned)	2.03	2.03	2.03	2.03	2.03	…	2.03
	C (Unplanned)	19.07	19.05	19.04	19.02	19.00	…	18.90
	Total	**21.10**	**21.08**	**21.06**	**21.04**	**21.02**	**…**	**20.93**
SAIFI	B (Planned)	0.01	0.01	0.01	0.01	0.01	…	0.01
	C (Unplanned)	0.56	0.56	0.56	0.56	0.56	…	0.55
	Total	**0.57**	**0.57**	**0.57**	**0.57**	**0.56**	**…**	**0.56**

The underlying reliability for significant network areas and voltage levels can be broadly summarised as shown in Table 16:

Table 16: Expected fault frequency and restoration time

General location	Expected reliability	
Invercargill CBD 33kV Fault 11kV Fault	Frequency of faults ▪ One every 20 years ▪ One every 1.5 years	Estimated restoration[3]: ▪ 1 min ▪ 15 min
Invercargill other than CBD 33kV Fault 11kV Fault	Frequency of faults ▪ One every 7 years ▪ 4.5 every year	Estimated restoration: ▪ 15 min ▪ 30 min
Bluff 33kV Fault 11kV Fault	Frequency of faults ▪ 3 every year ▪ 5 every year	Estimated restoration: ▪ 1 min ▪ 45 min

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.

Table 17 shows the thresholds which the Commerce Commission applies to EIL'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.

Because of EIL's very good reliability and low annual fault number averaging effects on a random fault pattern are not strong in any particular year. Previous boundary values were set very high for EIL meaning extreme events would not be normalised putting EIL at risk of breaching the regulatory limits. The new normalisation boundaries should cater much better to EIL's highly reliable network and assist in keeping SAIDI and SAIFI within their respective limits.

Table 17: EIL Reliability Thresholds

	Target	Collar	Cap	Limit	Boundary
SAIDI	24.08	17.03	31.13	31.13 (previously 45.65)	3.24 (previously 40.63)
SAIFI	0.594	0.415	0.772	0.772 (previously 1.13)	0.080 (previously 1.09)

The Cap, Target and Collar are used as part of a revenue incentive scheme for improving reliability on the network where cost effective. A total of $136,000 (equivalent to 1% of the starting price maximum allowable revenue for the regulatory period) is the "revenue at risk" split equally between SAIDI and SAIFI at $68,000 each. For performance at the Target level, which is calculated as EIL's average historical reliability levels, there is no adjustment to EILs revenue. For performance worse than the Target EIL incurs a pro rata revenue loss up to the Cap where the maximum penalty of $68,000 is imposed. Conversely for performance better than the reliability target EIL earns a pro rata

[3] Except if supplied directly off the faulty section of line or cable.

revenue gain down to the Collar where the maximum bonus of $68,000 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.

Secondary Customer Service Levels

Secondary service levels are the attributes of service that EIL 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 EIL 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).

Table 18: Secondary Service Level Projections

Attribute	Measure	2016/17	2017/18	…	2025/26
Planned Outages	Provide sufficient information. {CES: Q3(a)}	>80%	>80%	…	>80%
	Satisfaction regarding amount of notice. {CES: Q3(c)}	>80%	>80%	…	>80%
	Acceptance of maximum of one planned outage every two years. {CES: Q1}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting two hours on average. {CES: Q1}	>50%	>50%	…	>50%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q4(b)}	>80%	>80%	…	>80%
	Information supplied was satisfactory. {CES: Q8(b)}	>80%	>80%	…	>80%
	PowerNet first choice to contact for faults. {CES: Q6}	>35%	>35%	…	>50%
Supply Quality	Number of customers who have made voltage complaints {NR}	<10	<10	…	<10
	Number of customers who have justified voltage complaints regarding power quality.	<4	<3	…	<2

{ } indicates information source; CES = Customer Engagement Survey using independent consultant to undertake phone survey, NR = Network Report provided monthly to the EIL Board.

Customer Satisfaction Surveys was previously used understand customers' satisfaction regarding new connections with projections included in Table 18 but has been discontinued due to an extremely poor response rate. Alternative methods of gathering this information are being investigated including the possibility of adding similar questions to the existing Customer Engagement Survey (carried out by an independent consultant by phone).

Other Service Levels

In addition to the service levels that are of primary and secondary importance to customers and which they pay for, there are a number of service levels that benefit other stakeholders such as safety, amenity value, absence of electrical interference and performance data. Some (in fact most) of these service levels are imposed on EIL by statute and while they are for the public good, i.e. necessary for the proper functioning of a safe and orderly community, EIL 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 EIL'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 EIL 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 EIL 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 EIL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or EIL'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 EIL 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.

EIL 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 with the complete listing of these measures included in EIL's disclosure to 31 March 2012 and with listing and analysis also on the Commerce Commission website
http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

Financial Efficiency Measures

EIL has redefined its financial efficiency measures to take advantage of the benchmarking opportunities available under the current Information Disclosure format. To capture the level of efficiency in both sides of the business, the new measures fall into two groups:

- Network OPEX metrics
- Non-Network OPEX metrics

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, EIL 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.

EIL therefore has six financial efficiency targets as shown in Table 20:

Table 20: Financial Efficiency Targets

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2016/17	$92	$2,398	$10,504	$179	$4,646	$20,347
2017/18	$94	$2,431	$10,654	$182	$4,716	$20,667
2018/19	$92	$2,377	$10,433	$184	$4,746	$20,828
2019/20	$92	$2,367	$10,398	$184	$4,725	$20,758
2020/21	$92	$2,356	$10,365	$184	$4,704	$20,690
2021/22	$92	$2,346	$10,331	$184	$4,683	$20,622

Measure	Network			Non-Network		
	OPEX/ICP	OPEX/km	OPEX/MVA	OPEX/ICP	OPEX/km	OPEX/MVA
2022/23	$94	$2,377	$10,481	$184	$4,662	$20,555
2023/24	$92	$2,325	$10,263	$184	$4,642	$20,488
2024/25	$92	$2,315	$10,230	$183	$4,622	$20,422
2025/26	$92	$2,305	$10,197	$183	$4,602	$20,356

Dollar values as constant 2016 dollars.

Energy Delivery Efficiency Measures

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

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

Slight improvements are targeted but 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.

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	2016/17	2018/19	…	2025/26
Load Factor	50%	50%	…	50%
Loss Ratio	5.5%	5.5%	…	5.5%
Capacity Utilisation	40%	40%	…	45%

3.3. Service Level Justification

EIL'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 EIL 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 service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- EIL'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

Historical Trends

When setting EIL'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 targeted reliability and energy efficiency service levels are listed in Table 22 and customer satisfaction as indicated from past surveys are shown in Table 23.

SAIDI and SAIFI for future years (starting with the 2015/16 year) will be calculated using the new methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. Previously disclosed reliability results are shown however a recalculation of EIL's SAIDI and SAIFI using the new default price-quality path method have been completed and are also shown as these are the more relevant figures used in EIL's trending and forecasting.

Table 22: Reliability and Energy Efficiency History

Measure		2010/11	2011/12	2012/13	2013/14	2014/15
SAIDI	Previous Disclosure Method	44.7	63.6	31.8	25.1	41.3
	New DPP method	32.5	28.3	14.9	20.3	25.5
SAIFI	Previous Disclosure Method	1.18	1.30	0.33	0.52	0.79
	New DPP method	0.72	0.71	0.27	0.51	0.71
Load Factor		48%	48%	51%	49%	51%
Loss Ratio		3.8%	6.1%	5.4%	5.3%	5.6%
Capacity Utilisation		46.4%	47.1%	41.7%	42.1%	39.7%

Measure	2010/11	2011/12	2012/13	2013/14	2014/15
Network OPEX / ICP	$74	$1,960	$8,721	$179	$4,714
Network OPEX / km	$81	$2,127	$9,555	$192	$5,044
Network OPEX / MVA	$98	$2,565	$11,233	$214	$5,618
Non-Network OPEX / ICP	$109	$2,866	$12,470	$170	$4,461
Non-Network OPEX / km	$73	$1,913	$8,364	$167	$4,378
Non-Network OPEX / MVA	$74	$1,960	$8,721	$179	$4,714

Table 23: Customer Satisfaction History

Attribute	Measure	2010/11	2011/12	2012/13	2013/14	2014/15
New Connections	Phone: Friendliness and courtesy. {CSS: Q3c}	4.5	5	-*	5	-*
	Phone: Time taken to answer call. {CSS: Q3a}	4	5	-*	5	-*
	Overall level of service. {CSS: Q5}	4	4	-*	5	-*
	Work done to a standard which met your expectations. {CSS: Q4b}	4	4	-*	5	-*
Planned Outages	Provided sufficient information. {CES: Q3a}	80%	100%	100%	100%	91%
	Satisfaction regarding amount of notice. {CES: Q3c}	100%	100%	100%	81%	100%
	Acceptance of maximum of one planned outages every two years. {CES: Q1}	93%	99%	95%	98%	95%
	Acceptance of planned outages lasting two hours on average. {CES: Q1}	86%	91%	95%	95%	91%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES: Q4b}	88%	91%	80%	80%	67%
	Information supplied was satisfactory. {CES: Q8b}	88%	77%	67%	100%	100%
	PowerNet first choice to contact for faults. {CES: Q6}	12%	24%	30%	34%	19%**
Voltage Complaints	Number of customers who have made voltage complaints {NR}	2	2	9	5	5
	Number of customers who have justified voltage complaints regarding power quality	0	0	5	2	4

{ } indicates information source; CSS = Customer satisfaction survey undertaken by sending questionnaire to customers with invoices, CES = Customer engagement survey using independent consultant to undertake phone survey

*No responses received and have discontinued due to low response rate while investigating an alternative method for collecting this data. However have noted previous year responses were generally positive.

**However 61% indicated they would not contact anyone

Benchmarking

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 26 to Figure 36, helps identify where EIL might look to improve from current service levels. Particularly Nelson Electricity and to a lesser extent Orion and Wellington Electricity are considered as similar networks in terms of density and asset base and so comparisons from this perspective are also useful.

SAIFI - available EDB reliability results since 2013 show EIL is a leading network in minimising the number of supply interruptions that customers experience. EIL's position relative to other local EDBs suggests no significant improvement in SAIFI is warranted.

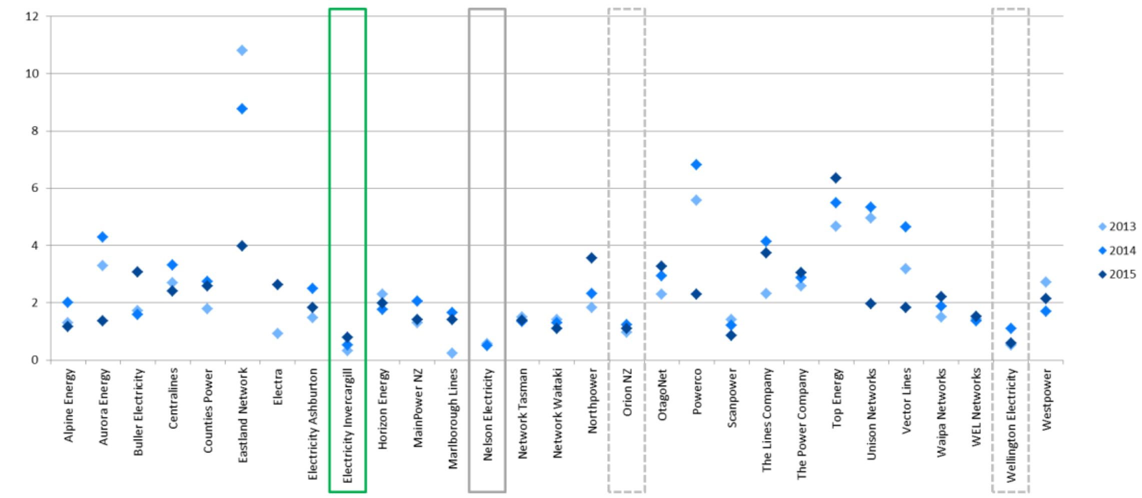

Figure 26: EIL SAIFI Comparison with Local EDBs

SAIDI – available EDB reliability results since 2013 show EIL is a leading network in minimising the amount of time without supply that customers experience. EIL's position relative to other local EDBs suggests no significant improvement in SAIDI is warranted.

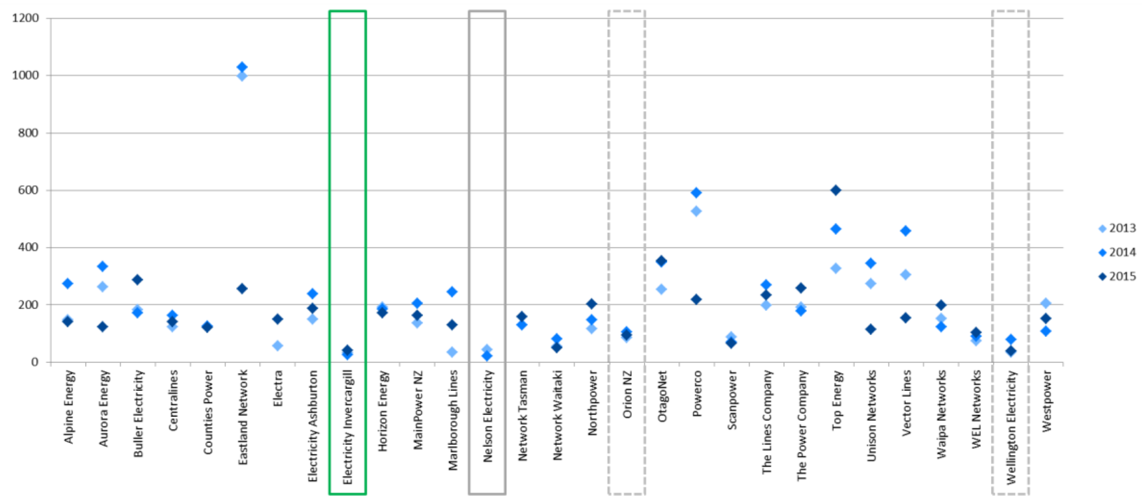

Figure 27: EIL SAIDI Comparison with Local EDBs

Load Factor - EIL's peak during winter months has not coincided with the LSI peak (tending to be late spring) over recent years. This meant that peak load control was not required in winter resulting in a higher peak with an adverse effect on load factor. There is also less diversity in customer consumption across the network as the area supplied is completely urban.

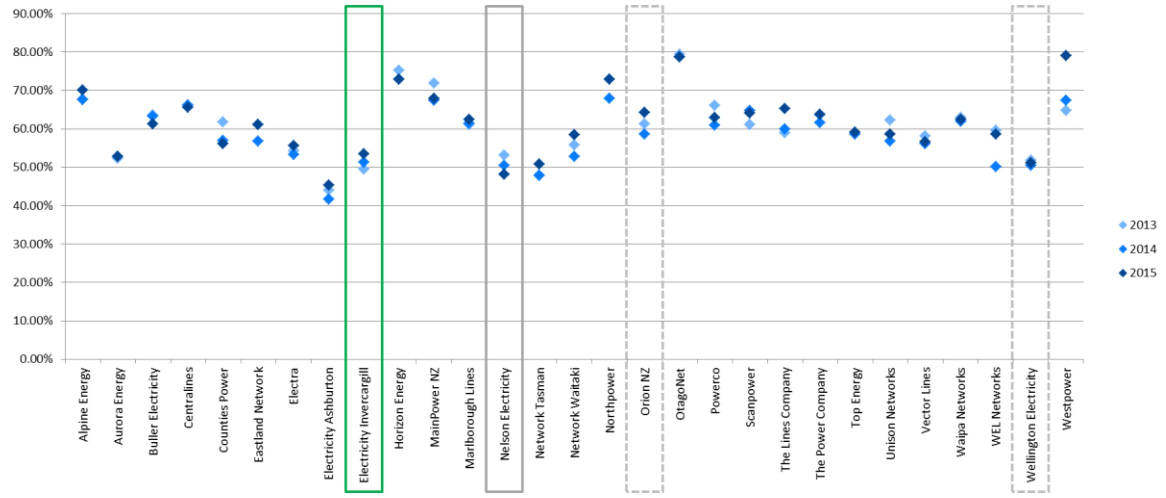

Figure 28: EIL Load Factor Comparison with Local EDBs

Comparison with other networks shows that EIL's load factor is relatively low and might be an area for improvement. However it is difficult to influence customer's consumption patterns since any line charge incentives offered are repackaged by retailers billing methodologies. Load factor is expected to remain at current levels in the short term.

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.

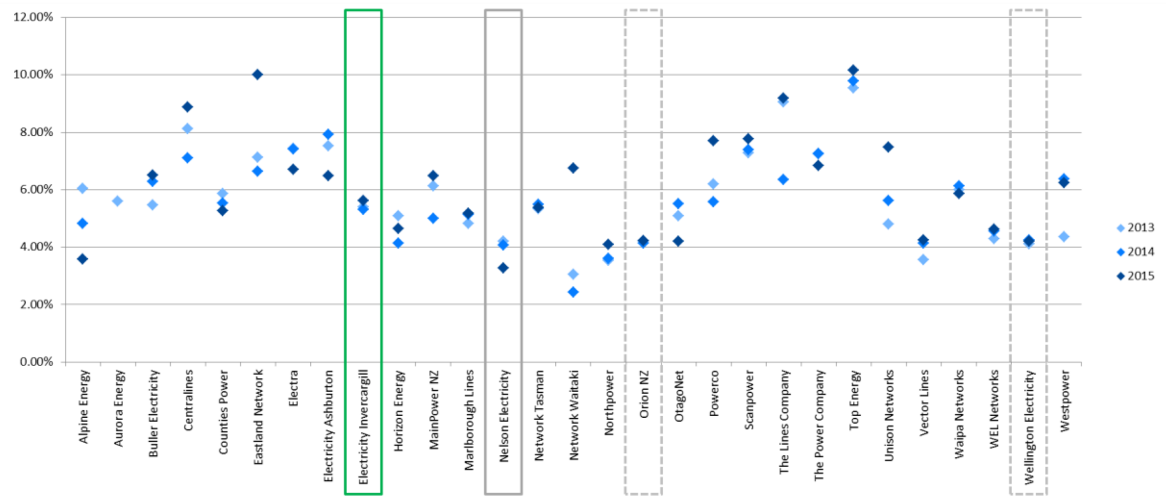

Figure 29: EIL Loss Ratio Comparison with Local EDBs

Comparison with other network companies shows EIL's network is moderately efficient. Trending over a five year period shows an increase in network losses however trending over most other time periods up to the last ten years shows a decrease. EIL can expect a long term average of about 5.5% to be maintained however year to year results can vary considerably due to retailer estimations and a slightly higher target has therefore been set.

Capacity Utilisation - optimisation of transformer size and numbers 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 EIL's capacity utilisation with other local EDBs highlights that EIL has the highest capacity utilisation factor therefore no strategies for improvement are warranted.

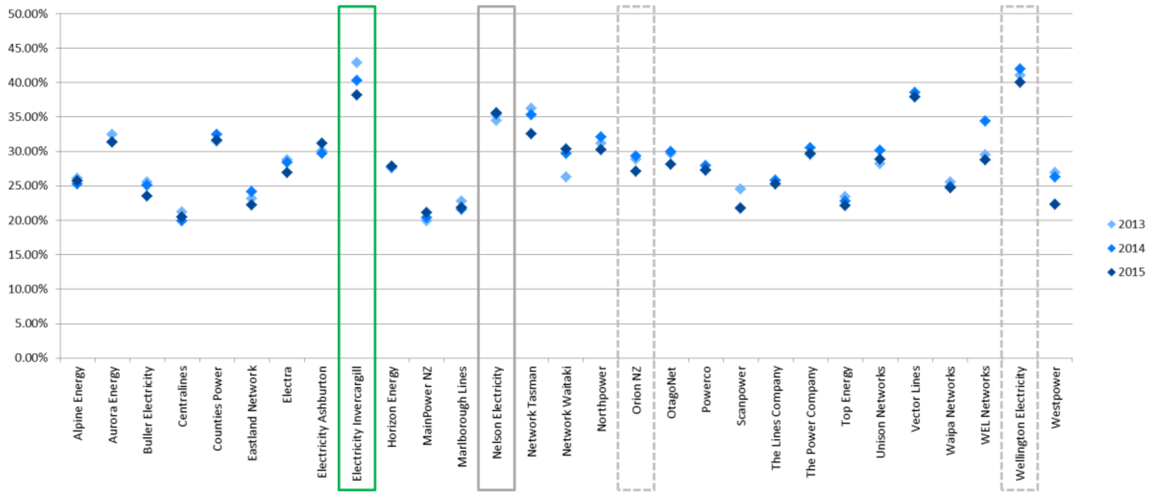

Figure 30: EIL Capacity Utilisation Comparison with Local EDBs

Financial efficiency – The six ratios that EIL has adopted as financial efficiency measures do not highlight any areas of concern as benchmarked against industry peers. Per ICP operational expenditure is average to good. Per km of network length operational expenditure is relatively high in comparison to industry peers however this is to be expected due to the high customer density and similar results can be seen from similar high density distribution networks. Per MVA of distribution transformer capacity operational expenditure is moderate.

Initiatives to improve scheduling and efficiency of PowerNet's workforce are being progressed and are anticipated to have a positive impact on future results.

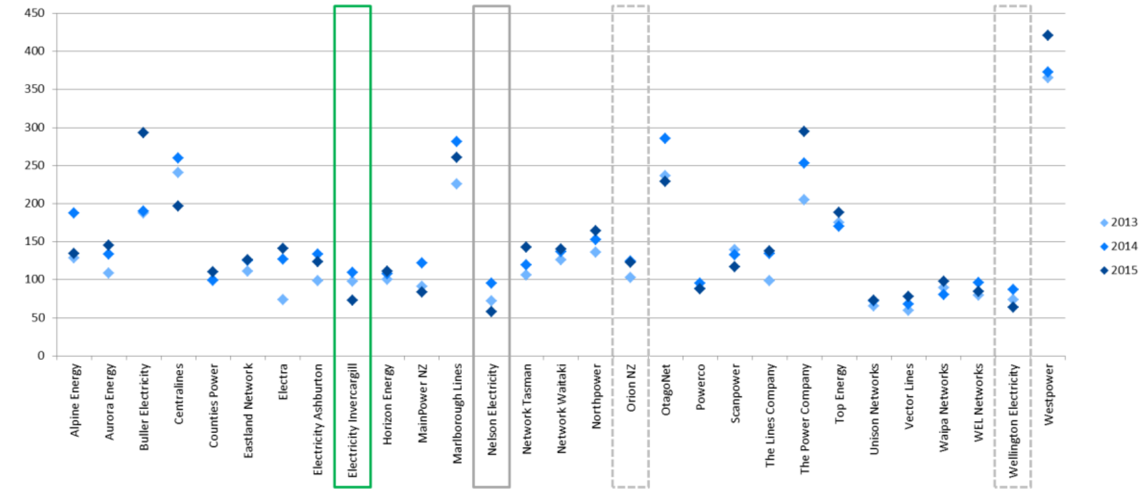

Figure 31: EIL Network OPEX/ICP Comparison with Local EDBs

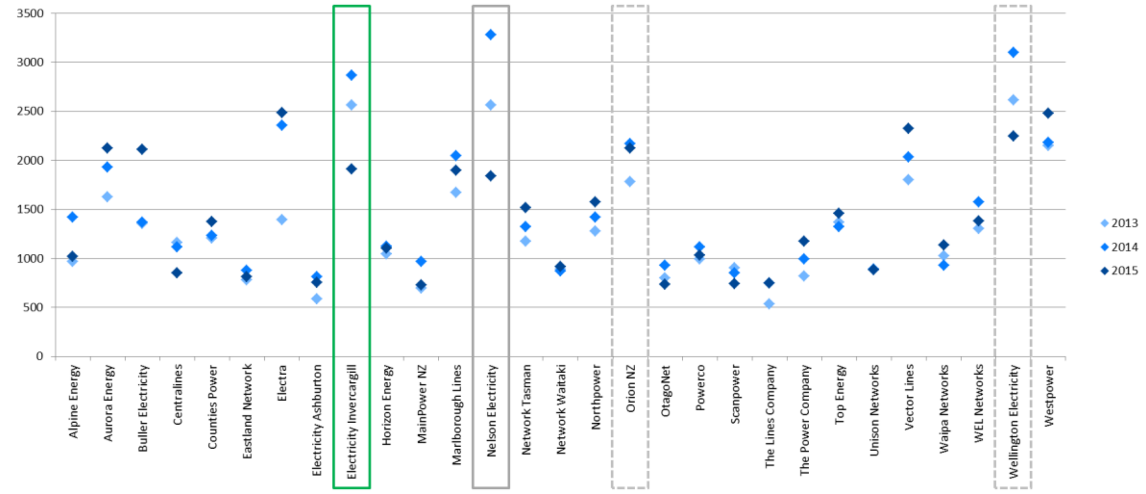

Figure 32: EIL Network OPEX/km Comparison with Local EDBs

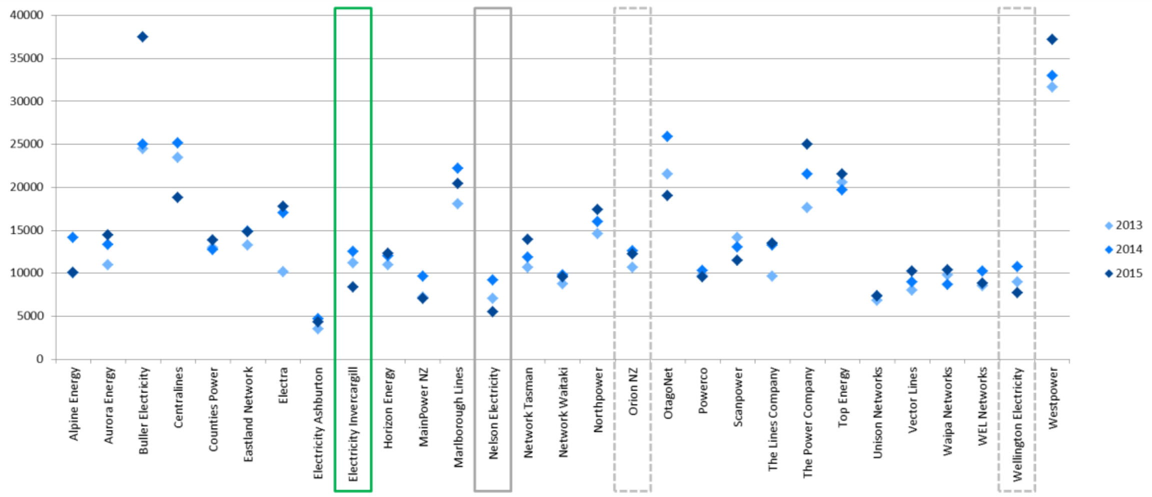

Figure 33: EIL Network OPEX/MVA Comparison with Local EDBs

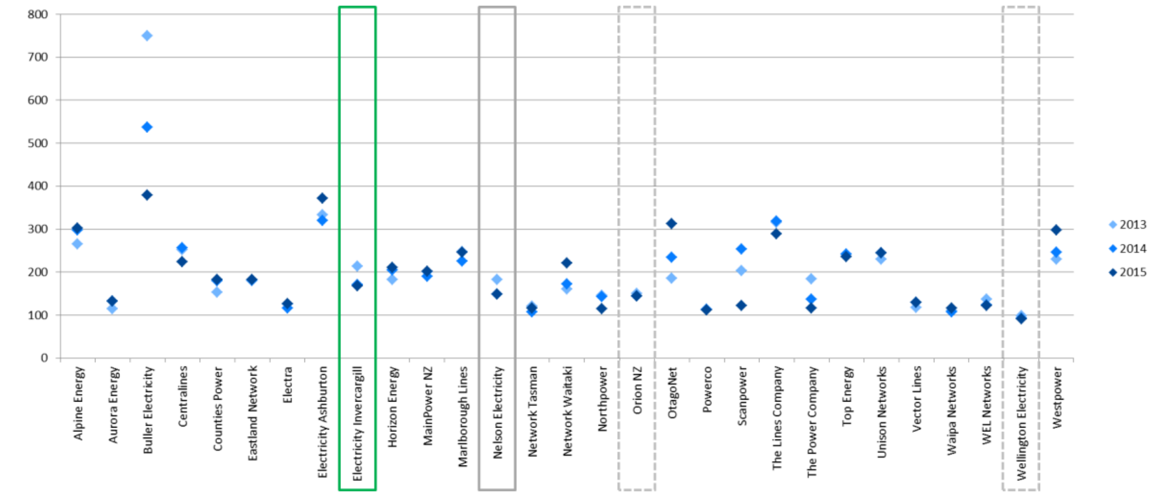

Figure 34: EIL Non-Network OPEX/ICP Comparison with Local EDBs

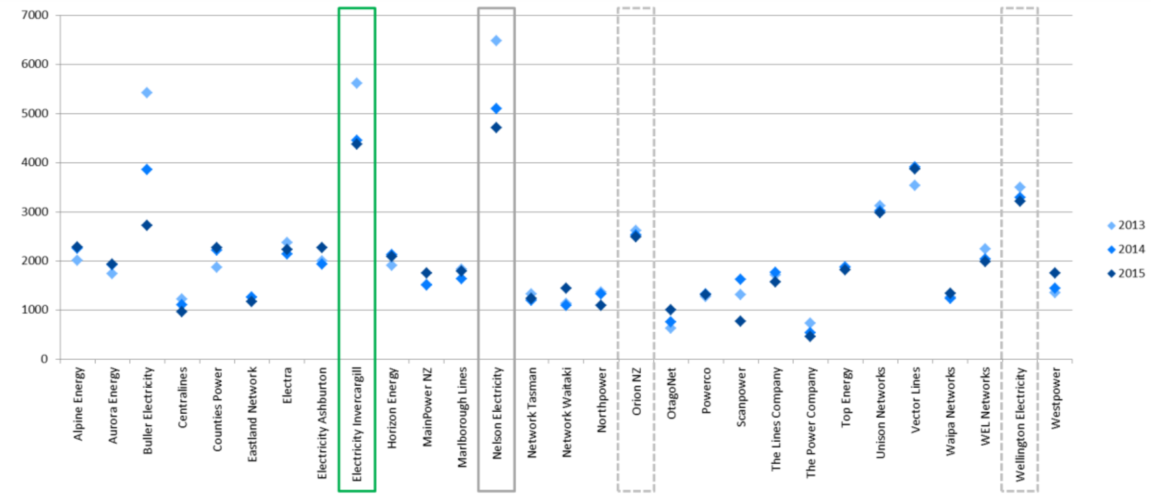

Figure 35: EIL Non-Network OPEX/km Comparison with Local EDBs

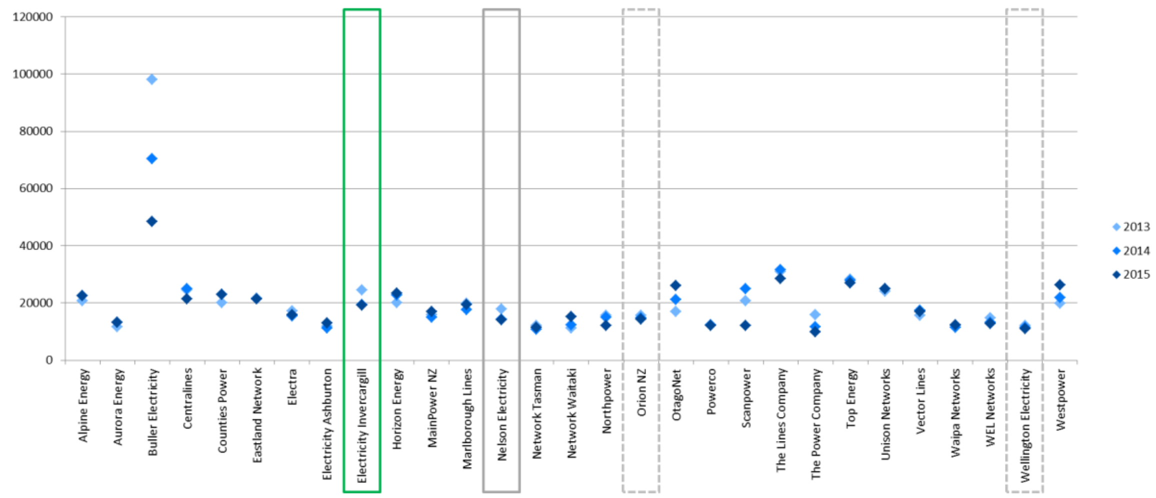

Figure 36: EIL Non-Network OPEX/MVA Comparison with Local EDBs

4. Development Planning

EIL 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 EIL'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 requires an increase in network capacity to match their additional load requirements. They may also be less direct such as 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 EIL's network development planning.

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. Load diversity tends to favour better load factor and capacity utilisation more and more with this aggregation of load up the network.

Demand growth creates the predominant driver for network development and 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. In meeting future demand while maintaining service levels, the first step is to determine if the projected demand will exceed any of EIL'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 EIL will then move to 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 section (see Cost Efficiency) which also embodies an overall preference for avoiding new capital expenditure. As new capacity has balance sheet, depreciation and ROI implications for EIL, endeavours will be made to meet demand by other, less investment-intensive means. This discussion also links strongly to EIL's discussion of asset life cycle in Lifecycle Planning.

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. The current roll out of smart meters will vastly improve ability to estimate loading and utilisation of asset capacity.	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 EIL's security standard set out later in this section (see Security Standards). 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.

Service Level Changes

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

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

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 Service Levels. 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 this approach is uneconomic as well as inherently limited. Essentially with a long term 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.

Cost Efficiency

In the interests of cost efficiency EIL aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost efficient with network development requires a “just enough, just in time” approach for the determination of appropriate new capacity and an appropriate level of standardisation; these strategies will be discussed later in this section. However before capital intensive upgrades are required the following options, in a broad order of preference, are considered when development triggers have been reached.

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. In reality, do nothing options would only be adopted if the benefit-cost ratios of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive that the do nothing option did not represent an unacceptable increase in risk to EIL. 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.
- Operational activities, in particular switching on the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Demand management using load control or using other methods to influence customers’ consumption patterns so that assets operate at levels below trigger points. Examples might

be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source to avoid new capacity. EIL notes that the effectiveness of line tariffs in influencing customer behaviour is diminished by the retailer's practice of repackaging fixed and variable charges.

- Install generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. These options would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. waste steam from a process.
- Modify an asset so that the asset's trigger point will move to a level that is not exceeded e.g. by adding forced cooling. This approach is more suited to larger classes of assets such as power transformers. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels but current capacity is not fully utilised.
- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily-loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.

Installing new or greater capacity assets is generally the next step which increases asset capacity to a level at which the relevant trigger point is not exceeded. An example would be to replace a 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.

Standardisation

Standardisation is an important strategy used by EIL 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" each time, 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 EIL's network. EIL 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 EIL's network, similar projects are often managed by PowerNet on other networks and where project scopes overlap design "building blocks" may be utilised in several designs. Through this approach a degree of standardisation is achieved with each consecutive design utilising these building blocks from the latest previous design. Continuous improvement is realised with lessons learnt able to be incorporated at each iteration.

Virtually all of the EIL 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 Cable Cross-linked Polyethylene (XLPE)	Stocking of common sizes, lower cost Rating, ease of use.
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Chlorine, Helium, Iodine, Neon or Aluminium conductor steel reinforced (ACSR) – Magpie, Squirrel, Flounder, Snipe Low Voltage Aerial Bundled Cable (ABC): 35, 50 & 95mm^{2}Al (two or four core).	Low corrosion, low resistance, cost, stocking of common sizes Higher strength (longer spans, snow load) Safety, lower cost.
Structures	Poles: Busck pre-stressed concrete Cross-arms: Solid hardwood	Consistent performance, long life, strength 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 (residential areas - size based on domestic customer numbers), equipment type, manufacturer etc	Minimise spares, familiarity, proven history, cover-all specification.
Ring Main Units	Standard ratings, equipment type, manufacturer etc	Minimise spares, familiarity, proven history, cover-all specification.

Security 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. EIL'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 and therefore maintenance of desired security must avoid demand growth eroding surplus capacity which can easily occur. 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 whereas rural area feeders may need significant line extension to meet adjacent feeders. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair. This requires those adjacent feeders to maintain spare capacity.

Duplication of assets: so that in normal service both sets of assets share the load. Then when a duplicated asset malfunctions it can be isolated and all load is transferred to the remaining asset. This approach generally provides the greatest security as there is typically no interruption to supply though duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent assets.

Use of generation: may be used to either provide an alternate supply or at least supplement supply and reduce capacity requirements for backup assets. To be of any use from a security perspective, generation would need to have close to 100% availability. Diesel generation has good availability so is practically able to be 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 so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.

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

The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feeding on the 11kV providing a third tier of security. Table 26 summarises the security standards adopted by EIL. Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride this standard.

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.

Determining Capacity

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within EIL’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 for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over investment however if assets are undersized the asset will need to be replaced early before their natural end of life. In many cases standardisation will limit the options available to assist in the selection of capacity.

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

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

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 27. Clearly understanding load growth into the future is crucial to making sound investment decisions. The method and considerations for forecasting network demand is discussed later in this section.

Table 27: Capacity Selection Criteria

Network Asset	Capacity Criteria Selection	
Subtransmission network	Allow expected demand growth over life time of assets	
Power transformers	Allow expected demand growth over 20 years then relocate	
Switchgear	Allow expected demand growth over life time 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	Rural
	11kV: -3%	11kV: -4%
	LV: -5%	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

Energy Efficiency

EIL 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 EIL will use these solutions, for example specifying low loss cores used in the magnetic circuits of transformers. Otherwise power consumed by EIL 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.

Additionally EIL formed the Southland Warm Homes Trust (SWHT) in 2008 with the Southland Power Trust (TPCL's shareholder). The SWHT works in partnership with government, the Energy Efficiency and Conservation Authority (EECA) and local funders to provide subsidies for insulation and heating assessments and retrofits for warmer, healthier homes across the Deep South region. PowerNet provides administration and financial reporting services on behalf of the (SWHT).

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

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

Prioritising Development Projects

Development projects are prioritised in line with the principles set out in Drivers and Constraints – Managing Conflicting Stakeholder Interests 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 EIL Board for approval with supporting justification in the updated AMP.

4.2. Forecasting Demand and Constraints

As development projects can take many months or even years to complete, understanding when trigger points may be exceeded in the future is necessary to ensure capacity can be made available by the time it is needed. This involves 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.

EIL's Current Demand

EIL's maximum demand (MD) of 60.73MW 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 EIL Bluff MD of 4.23MW occurred at a different time to both the overall EIL MD and the LSI peak. The EIL coincident demand at the time of the LSI peak was 54.79MW with 3.61MW of that load contributed by Bluff EIL. The individual maximum demands are shown in Figure 37.

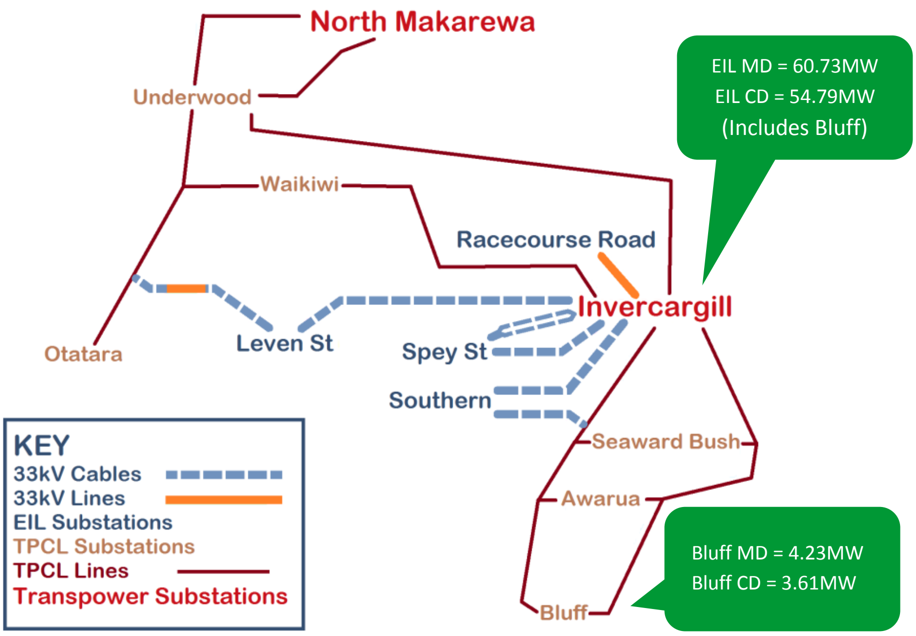

Figure 37: GXP and Generation Demands

Demand History and Trend

Growth trends are difficult to establish as there is somewhat random variation on top of underlying growth. Generally the trend taken over the latest ten year period will be quite different year to year as the most recent years' data is included and data beyond ten years is excluded. This is again quite different to a 20 year trend. Longer term trends tend to "average" out the random variations but lose sight of 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 effecting consumption patterns before arriving at a reasonable estimate of growth which can be used for forecasting future demand and consumption.

Figure 38 shows the overall EIL data since 1950 and highlights the flattening out since the late '80s. Recent increases in maximum demand have been affected by changes in Transpower's pricing methodology; these changes are not apparent in energy growth.

Analysis of historic demand and energy usage over the last 10 years or so (allowing for the step change created by Transpower's change to their transmission pricing methodology) shows maximum demand growth is low at about 0.13% and energy consumption growth at -0.6% (declining). The following sections examine in detail the most significant drivers of the network demand over the next 10 to 15 years.

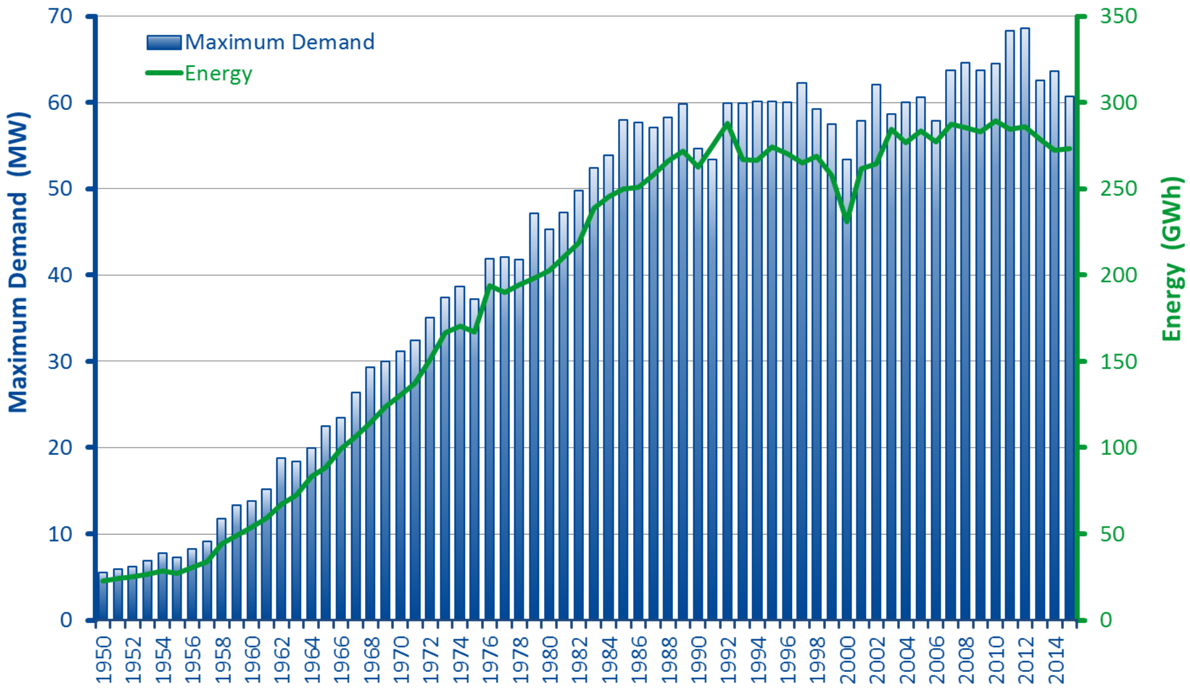

Figure 38: Maximum Demand and Energy Transmitted

Each zone substation recorded the maximum demands as listed in Table 29. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand. Simple trend lines over recent years show negative growth rates in maximum demand on each of the Invercargill substations. However it is believed that extended load transfers between the zone substations have distorted trends seen at this level and overall EIL maximum demand trending is thought to give a better representation of growth.

Table 29: Substation Demand

Zone Substation	Max Demand (MVA)	99.9% Percentile Demand (MVA)							
	2014/15	2014/15	2013/14	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08
Doon St*	19.8	17.0	17.2	14.5	13.6	22.7	22.8	22.0	23.7
Leven St	17.1	15.2	15.2	17.9	18.3	17.7	18.3	17.7	19.0
Racecourse Rd	10.9	9.2	9.4	12.7	12.7	9.7	10.1	9.4	10.1
Southern	9.8	7.9	13.5	14.3	14.2	12.5	12.5	11.7	12.4
Bluff (TPCL)	4.7	4.5	4.6	4.5	4.5	4.4	4.6	4.6	4.1

*Note Doon Street load was transferred onto the new Spey Street substation over the last year (2015/16).

It has been noted in the past that growth rates tend to be slightly higher in the commercial and industrial areas of the network. Trends for these areas have become difficult to extract due to the shifting of load between substation feeders in recent years to manage substation loads and security risks around staging of previous development projects. However regardless of the variation of growth affecting the distribution network areas the loading on each zone substation can be monitored with respect to development triggers and managed by shifting load as required.

Drivers of Future Demand

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

Table 30: Demographics and Lifestyle Drivers of Future Demand

Demographics and Lifestyle	
Population Growth and Decline	**Effect:** Population static initially but increasing in future years to approx. 10% above 2016 levels by 2025. This corresponds to a similar increase in demand of 10% assuming similar housing and living arrangements and employment is available from a similar business profile.
Description: The population of EIL's distribution area is approximately 35,000 of which the Bluff area accounts for approximately 5%. Census population projections for EIL's distribution area are shown in Figure 39. The high projection shows population slightly increasing with medium and low projections showing a decline out to 2026. Population trends have been noticed with concern by Southlanders and in response the Southland Regional Development Strategy has as its main target an increase in population to 105,000 by 2025 for the Southland region. This represents an average increase of about 1000 people per year from now and if achieved would be expected to happen gradually at first and gain momentum in future years. It is expected that the vast majority of growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. Further, Southland Institute of Technology as a tertiary education provider is seen as an important attractor for potential migrants located within central Invercargill. Invercargill would attract the majority of potential migrants however the Invercargill area supplied by EIL is surrounded by TPCL which supplies the outer regions of the city. Expansion of Invercargill for additional	

Demographics and Lifestyle	
housing would therefore often be outside of EIL's network boundary although this expansion requires new housing and individuals or families in a sufficient financial position. EIL does have some undeveloped land suitable for housing and there is further potential for in-build with subdivided sections which if increased demand eventuates would be utilised to some extent. Business expansion is also a target for the Southland Regional Development Plan and again Invercargill would expect to be a key location for this to occur. A commercial subdivision to support any potential new commercial building is available within EIL's Invercargill network area.	
Housing Density and Utilisation	**Effect:** Overall support of domestic power demand growth from increasing population as described above. Effects of increased housing density is somewhat offset by increasing housing utilisation as more people share heating and other power requirements.
Description: Housing density and utilisation can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. An increase in the student population may increase demand for higher density student accommodation facilities near central Invercargill.	
Rural Migration to Urban Areas	**Effect:** Population growth especially from retirees (baby boomers) is expected to have a limited driver for increased demand. Effect is captured in population growth effect above discussed above.
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has been seen in Southland also. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This supports the above assumption that Southland's urban areas, particularly Invercargill is likely to see the vast majority of population growth if the population growth strategy is successful. Figure 39 shows the number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2026. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. Building in new areas on the outskirts of Invercargill, outside of EIL's network area or demolishing older houses to replace with more efficiently heated homes may be common for these retirees. Some additional support for retail business in Invercargill may result but overall this would have a minor impact on power demand and as this is not a new effect it is largely included in previous years trending.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months. Consumer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for EIL over the next ten years. Incorporates growth anticipated from Table 31; council fuel burner constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. For EIL's customers concerns with loss of heating during outages are close to negated by the high supply	

Demographics and Lifestyle	
reliability these customers receive. However heat pump installation cost is a barrier for many people and some prefer the ambience of other heat sources. Therefore complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period of time. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run. Conversion will be both driven and constrained by the Breathe Easy clean air initiative discussed in Table 31.	
Electricity Affordability	**Effect:** Minimal change in demand for power supply is expected due to changes in electricity prices. Future change is likely to be a continuation of current demand trends.
Description: Consumption and demand are relatively inelastic to changes in power price as it is seen as an essential service for most people. Improving energy efficiency for heating and appliances and future technology such as smart meters and appliances are expected to counteract effects of increasing electricity prices continuing current trends.	

Figure 39 shows population projections for EIL's network area as estimated by Statistics New Zealand from 2013 Census data. As well as total population the group 65 years and older is shown highlighting the predicted significant aging of the population.

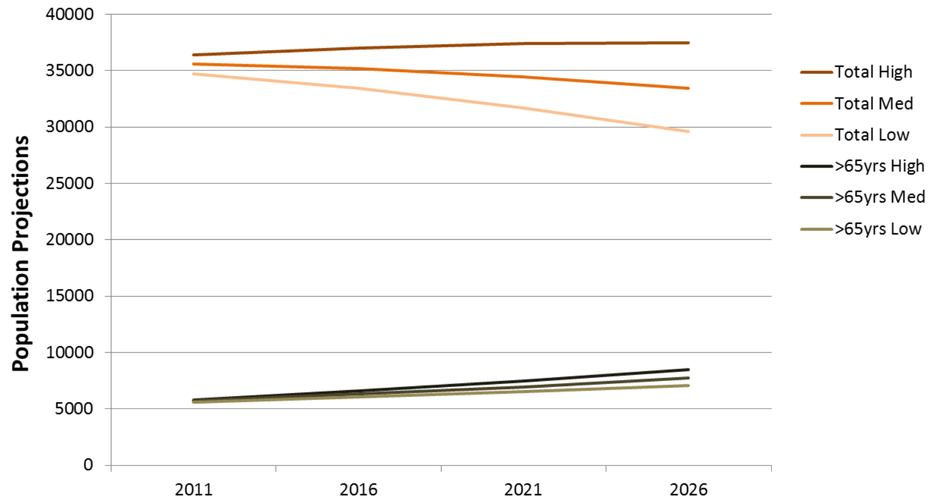

Figure 39: EIL Population Projections

Table 31: Environment and Climate Drivers of Future Demand

Environment and Climate	
Council Fuel Burner Constraints	**Effect:** Growth due to heat pump conversion incorporated in the low growth rate estimated above in convenience of electrical heating.
Description: The Breathe Easy initiative is a review of the Regional Air Quality Plan for Southland and will bring into force rules aimed improving air quality by phasing out the use of solid fuel burners that do not meet the National Environmental Standard. The rules prohibit the use of non-approved burners from 2017 to 2034 based on the date of the burner's installation generally allowing existing burners to be used for a period of 20 years from installation. Conversion with be both driven and constrained by the Breathe Easy clean initiative. Often heat pumps will be selected as replacement for prohibited burners as they are phased-out however those opting for efficient burners as replacements are less likely to install heat pumps for a significant period afterward.	

Environment and Climate	
Energy Conservation Initiatives	**Effect:** Customers are responding to marketing, strategies and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.
Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating (see above section Energy Efficiency).	
Increasing Ambient Temperature	**Effect:** No impact on maximum demand but potentially some improvement in load factor.
Description: Increasing ambient temperature predicted by climate scientists may create increased demand for cooling systems. This increased consumption would occur in the warmer months and therefore not coincide with the current peak demand occurring in the winter months being dominated by heating requirements. It would take a very large change in ambient temperature for peak consumption to be dominated by cooling in summer months and is expected to simply improve load factor by a small degree.	

Table 32: Economic Drivers of Future Demand

Economy	
Major Industry Continuance or Growth	**Effect:** The most likely scenario is considered that in which existing industries will continue and no major new industries will eventuate therefore no change from existing trends forecasted.
Description: Dairy Industry, Tiwai, Major Petrochemical Extraction or Processing etc Tiwai aluminium smelter takes supply directly from the transmission grid however it helps support many businesses and individuals both directly and indirectly and loss of this business could have a major impact on the local economy and therefore growth on EIL's network in Invercargill and Bluff. It is considered most likely Tiwai will continue to be viable in the short to medium term at least and therefore no change to growth forecasts has been made. The Great Southern Basin is a potentially viable location for deep water oil drilling. Possible flow on effects if a deposit is developed could create infrastructure and demand at the Bluff port however Dunedin port could be favoured over Bluff. The likelihood and level of growth from this effect is quite uncertain and has therefore not been included in forecasted growth.	
$NZD Variation & Commodity Cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.
Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident.	

Table 33: Drivers of Future Demand

Technology	
Electric Vehicles	**Effect:** No significant effect over the ten year planning horizon.
Description: With significant penetration into the transport sector, electric vehicles have the potential to have a large impact on network demand. However it is not considered likely that electric vehicles will be widely used in the next ten years. It is expected that the majority of this load should be and will be able to be managed so that it is consumed at off-peak times (especially overnight) and therefore would have	

minimal 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.

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 seen so far has 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 EIL's network to date although the trend is gradually increasing 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.

Energy Efficiency	**Effect:** Negative growth driver accounted a part of the above discussed driver Energy conservation initiatives.

Description: Improving energy efficiency has been a government strategy for several years as discussed in Table 31; Energy Conservation Initiatives. It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.

On-line shopping	**Effect:** Likely to negatively affect the business sector in EIL's network area however the overall effect on demand is expected to be relatively insignificant.

Description: Shopping online continues to become more and more popular with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within EIL's network area. However there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in EIL's area.

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 electronic 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.

Demand Forecasts

The overall impact of the drivers explained above is a slow growth rate for maximum demand on EIL's network of 1.24% per annum. EIL's total maximum demand is forecast to increase from about 65.3MW in 2016/17 to about 72.13MW in 2025/26. Table 34 shows this growth on a per substation basis as the most appropriate network level for identifying constraints on the network.

Table 34: Existing Substations Growth Projection

Substation	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
Spey Street	20.4	20.6	20.9	21.1	21.4	21.7	21.9	22.2	22.5	22.8
Leven Street	20.8	21.1	21.4	21.6	21.9	22.2	22.4	22.7	23.0	23.3
Racecourse Road	13.2	13.4	13.6	13.7	13.9	14.1	14.2	14.4	14.6	14.8
Southern	19.8	20.1	20.3	20.6	20.8	21.1	21.3	21.6	21.9	22.1
Bluff	5.2	5.2	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8

These projected substation demands are considered the most likely outlook and are the basis for EIL's network development planning. It is accepted that there is significant uncertainty in these forecasts and actual future demands may depart significantly from these levels. Forecasts are updated annually to ensure plans are able to react quickly to any changes from previous assumptions.

If growth rates decline, schedules for projects to address capacity constraints are correspondingly delayed so as to minimise the risk of over investing. Ultimately EIL seeks to realise growth opportunities as they arise which means developing the network to alleviate constraints as required accepting, as with any investment that some risk is involved. Risk of stranding of new assets is managed where appropriate through capacity guarantee contracts with new customers. Otherwise risk is minimised by avoiding investment by utilising whatever options are available to defer investment until absolutely necessary while maintaining desired service levels.

Higher growth rates are also possible and present a risk of missed opportunity for growth for both EIL and EIL's customers. Growth affecting the entire network is most likely to come with sufficient warning to allow resources to be adjusted as required. Any large scale developments are likely to be largely funded by external investors through capital contributions and EIL generally has the ability to respond quickly to unforeseen large scale one off developments. Naturally there are limits to this capability and negotiation may be required around timing of project delivery. Unfortunately experience shows that while endeavours are made to warn customers of potential lead times around providing additional network capacity requests for supply tend to come relatively late in their planning processes due to commercial sensitivities.

Constraints Arising from Estimated Demand

The Invercargill GXP has a firm capacity of 109MVA and therefore with the GXP demand at 88MW has room for growth well beyond the ten year planning horizon at the forecast growth rates and with the potential for load control which could be utilised if necessary. There are no constraints on the subtransmission network that prevent the zone substation capacities being utilised therefore it is sufficient to consider the zone substations capacity and security.

Table 35 identifies the projected maximum demands at zone substation level at the end of the ten year planning horizon, along with the provision expected to be made for future growth. This assumes no unforeseen changes in growth rates, as estimated from demand graph trends, or step changes due to connection or loss of large customers. Projected annual maximum demands incorporating the growth provisions identified is then shown in Table 36 and 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.

Table 35: Substation Demand Growth Rates

Substation	MD 2016/17	MD 2025/26	Provision for Growth
Spey Street	20.4	22.8	Spey Street was recently commissioned as a new substation replacing the old Doon Street substation as part of a major development project for EIL. Spey Street has a capacity of 72MVA and a firm rating of 36MVA and is adequate for the anticipated load over the ten year planning horizon.
Leven Street	20.8	23.3	Leven Street has a capacity of 46MVA and a firm rating of 23MVA. The firm rating will just be exceeded at the end of the ten year planning period and will likely utilise load transfer to the other zone substations as necessary to manage this capacity constraint.
Southern	13.2	14.8	Southern substation has a capacity of 23MVA available from its single transformer. However the maximum demand is now exceeding the 12MVA security trigger for upgrading this substation to AAA security by adding an additional transformer. Load transfer to the other zone substations will be utilised as necessary to manage this capacity constraint up to the end of the ten year planning horizon when forecast demand is anticipated to reach capacity development triggers at all of the Invercargill zone substations. Upgrade to AAA security will be required by this time. Earlier demand forecasts were indicating AAA security to be required at Southern substation in 2016 so these modifications were designed in line with a major replacement project for end of life assets at Southern substation which is now due. This project has been deferred until 2019/20 however to manage investment criteria with increased condition monitoring to manage risk around operating aged assets. The project scope will be reviewed prior to commencement but it is likely AAA security will still be achieved as part of the project as the most cost efficient delivery for the site renewal.
Racecourse Road	19.8	22.1	Racecourse Road substation has a capacity of 23MVA available from its single transformer. However the maximum demand is now exceeding the 12MVA security trigger for upgrading this

Substation	MD 2016/17	MD 2025/26	Provision for Growth
			substation to AAA security by adding an additional transformer. Load transfer to the other zone substations will be utilised as necessary to manage this capacity constraint up to the end of the ten year planning horizon when forecasted demand is anticipated to reach capacity development triggers at all of the Invercargill zone substations. However the development and security upgrades at Southern substation are expected to allow further transfer of load so as to avoid exceeding this trigger.
Bluff (TPCL)	5.2	5.7	The Bluff substation has a firm capacity rating of 13MVA which provides for the anticipated growth in Bluff well beyond the ten year planning horizon.

Table 36: Substation Demands with Proposed Developments 2015 - 2020

Substation	Transfers 2016/17	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21	2021 /22	2022 /23	2023 /24	2024 /25	2025 /26
Spey Street	11.8	32.1	32.5	32.9	33.3	33.8	34.2	34.6	35.0	35.5	35.9
Leven Street		20.8	21.1	21.4	21.6	21.9	22.2	22.4	22.7	23.0	23.3
Racecourse Road	-2.5	10.7	10.9	11.0	11.1	11.3	11.4	11.6	11.7	11.8	12.0
Southern	-9.3	10.6	10.7	10.8	11.0	11.1	11.2	11.4	11.5	11.7	11.8
Bluff		5.2	5.2	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8

EIL's network is also manages other general constraints as described in Table 37.

Table 37: EIL Network Constraints and Intended Remedy

Constraint	Description	Management Approach
MV Cables	Some MV cables operate near full capacity and would be unable to supply load in backup scenarios.	Several feeder cables emanating from the new Spey Street substation have been replaced with higher capacity to provide greater capacity for contingency scenarios. Operational measures ensure cables are not overloaded and smaller MV cables may be protected with fuses.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored and transformers will be upsized or supplemented with additional units as appropriate. Underutilised transformers may be relocated before purchasing new.
LV Switching in CBD	Limited locations are available for above ground equipment.	Communication with the Council to determine appropriate locations for above ground link boxes has worked well.
Overhead Lines	The District Plan prohibits new overhead lines.	Underground cables have been utilised throughout Invercargill.

Distributed Generation and Demand Management

The Distributed Generation (DG) has been ignored due to the estimated low connection density of DG and the probability that only a small percentage of the capacity will be available during peaks.

Load Management is used when substation equipment is nearing overload, and during load transfers for maintenance, and hasn't been considered in the projected demands above except to note that historical demand records have included these effects when used from time to time.

4.3. Development Programme

EIL's development programme is shown in Table 38 at the end of this section and is described in the remainder of this section, except for replacement and renewal capital expenditure programmes which are described in Lifecycle Planning.

New Connections

This budget provides allowance for new connections to the network including subdivisions where a large number of customers may require connection. Each specific solution will depend on location and customer requirements.

Planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance.

Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.

The district plan requires all new network to be underground in Invercargill however Bluff may utilise overhead construction which tends to be a lower cost option.

Distributed generation as a network alternative tends to be intermittent so cannot be relied on without energy storage which could make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to most customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is perceived benefit to the customer or network.

Under $0.5M per annum on-going; CAPEX - Consumer Connections.

Radiator Additions and Zone Sub Tidy-up

Spey Street, a dual transformer AAA security fully indoor urban substation has been constructed over previous years and was commissioned in the 2015/16 year. The new substation is a replacement for the aged and earthquake risk prone Doon Street substation and increases capacity for Invercargill's central city substation to 72MVA and its firm rating to 36MVA. Refer to EIL's previous 2015 AMP for details of this project including alternative options considered and justification for substation as constructed.

This is a minor project to carryout tidy up after the completion of the Spey street substation construction. During installation of the cooling radiators on the Spey Street T2 transformer, corrosion was discovered in four of the ten radiators which were deemed unsuitable to be put into service. The transformer was commissioned with the serviceable radiators and is able to operate at a reduced rating which is sufficient for the current load on the unit. Replacement radiators are required to be supplied from the manufacturer but were not available in time for installation in the 2015/16 year.

This budget is required to establish the full rating of the T2 36MVA transformer at Spey Street by installing the replacement radiators when they become available. This budget also covers minor tidy-up work required at Spey Street such as completing as-built drawings for the substation. The budget for 2016/17 reflects EIL's expectation that cost for replacement of radiators will be met by the manufacturer.

Cost under $0.5M 2016/17; CAPEX – System Growth.

Doon Street Reconfiguration

This project was previously managed and disclosed under the title "Extend Oil Filled 33kV Cable" and is described as follows.

Over the last year the 33kV oil cables previously supplying Doon Street substation were paralleled and extended with an XLPE cable to create a second feeder to the new Spey Street substation. Three options were being considered as at the disclosure date of the previous AMP; refer to EIL's 2015 AMP for details. The option to retain the overhead terminations in their present location was chosen as the least cost option due to the expense involved with creating transition joints from oil filled to XLPE cable. It also avoids the risk associated with moving and working on the aged paper-oil insulated cables. The XLPE extension cable was run up one pole structure and a short cable between the two structures used to parallel the two oil cables. The budget for 2016/17 covers costs for completion of as-built drawings for the work completed at Doon Street.

Additionally the planned demolition and reinstatement works for the remaining Doon Street site has been deferred until the 2019/20 year. Furan analysis of oil and DP testing of a paper sample from the 23MVA Doon Street T1 transformer indicate that the winding insulation is significantly aged. The unit was planned to be removed from site refurbished and stored until completion of upgrades at Southern substation where the unit would then be put back into service to complete the upgrade to AAA security. However given the age indicators it is considered an unacceptable risk to spend the additional costs for the refurbishment, storage and transformer movements when the unit may still fail soon after installation. On the other hand the unit may provide several years of life allowing deferment of capital expenditure for a new 23MVA transformer. Deferring the demolition works at Doon Street allows the unit to remain in situ until Southern substation is upgraded and the Doon T1 transformer can be relocated to Southern substation for a reduced cost and more acceptable cost benefit risk level.

Cost under $0.5M 2016/17 and under $0.5M 2019/20; CAPEX – System Growth.

Southern Substation Upgrades

A major renewal and upgrade project has been planned for the Southern substation site as a combined solution for several development drivers. Several assets replacements are required at the substation as follows.

- The 11kV switchboard is due for fixed time replacement.
- The outdoor structures are showing signs of cracking and reinforcement rust.
- Air break switches and earth switches have reached expected life and show signs of deterioration.
- One of the two 33kV circuit breakers has reached end of expected life and the other has significant rusting (ex-Bluff).
- The control building is in need of significant maintenance.

Additionally seismic assessment determined the Southern substation building as at 17% of new building standard as well as the outdoor structures also being below sufficient strength for sufficient resilience in a significant earth quake.

The substation load was previously forecast to reach the threshold in EIL's security standard where upgrade to AAA security is required (no interruption for any single failure event). The latest revision of demand forecasts has pushed out this requirement approximately five years beyond the intended completion date. The scope will be reviewed prior to this project commencing however with the design now completed and spare assets available it is likely the AAA security provision will remain within the scope for this project.

Planned upgrades

A staged approach toward a fully indoor substation is planned providing for due replacements, seismic resilience and AAA security for the substations growing demand.

Initially a new 100% "new building standard" importance level 3 strength building is to be constructed on the existing site with an increased size to house both the previously planned new 11kV switchboard, auxiliary services and a new 33kV switchboard to replace the outdoor circuit breakers, CTs, air break switches, earth switches, VTs and associated structures. The backup 33kV supply available from the cable that tee's off TPCL's overhead subtransmission line on Rockdale Road becomes a normally in service supply to realise AAA security and will be metered to reconcile consumption between networks.

The two 23MVA transformers (one to be relocated ex-Doon Street) are open bushing units not suitable for locating indoors and as they have expected remaining lives of eight and ten years the enclosure of these units are delayed for approximately ten years until they are replaced with new cable entry transformers. The initial building design takes into account future extension requirements. The oil cable termination and associated pressure tanks would most likely remain outdoor but shielded from stone throwers (an ongoing issue at the site) until ultimately due for replacement well beyond the planning horizon.

Options Considered

Several options were identified and considered as alternative options;

"Do nothing" was ruled out as inappropriate due to safety, security and reliability concerns with an earthquake prone building and primary assets beyond end of life at site.

A new building would be similar cost to the strengthening and maintenance requirements for retaining the existing building and brings additional benefits associated with a new modern building and was therefore considered the better option.

Renewal and upgrade of the existing outdoor concept was compared with the preferred indoor option described above including several variations around these themes. While there would be a small immediate cost benefit in retaining the outdoor concept the benefits of the indoor substation were considered to outweigh the difference in cost which amounts to about 5% of replacement cost for the overall replacement cost of the substation ($3.5 - 4 million). The additional benefits are extended life of indoor 33kV switchgear and reduced maintenance costs, a more comprehensive protection scheme and importantly a more reliable substation with protection from environmental impacts. The indoor solution protects from weather impacts, windblown rubbish and birds or other animal-life which reduce reliability for outdoor structure mounted equipment.

For EIL network reliability is very good, however this means that single events have the potential to significantly affect SAIDI and SAIFI reliability measures. Therefore it is particularly important for EIL to look for any opportunities to design out failure modes which have the potential to affect a large proportion of customers. A complete outage at Southern substation (supplying about a third or EIL's customers) would have a widespread impact on customers and there may be significant benefit for customers in terms of the "Value of Lost Load" which quickly adds up for an outage at a critical supply point such as a zone substation. Other benefits of the indoor option are improvements in public safety and visual perception.

Locating 33kV switchgear offsite was considered however the resulting configuration would require additional communications assisted protection eroding cost benefits and the overall relative reliability of the concept was not considered sufficient for EIL's network.

Building a fully indoor substation at another site was considered as an option to allow construction and an easy switchover before decommissioning of the existing site however the additional cost to reroute 33kV supply and 11kV feeder cables could not be justified while it is considered feasible to redevelop the existing site and utilising 11kV backup to load if necessary for brief periods. Another option was decommissioning the substation and extending feeders from a nearby substation were considered however again the impacts on reliability of grouping feeders is not considered appropriate for EIL and significant associated upgrade costs would mean little if any cost could be saved.

Implementation

Design was completed in 2015/16 however construction has been deferred from the timeframe set out in the previous AMPs to manage project cost within capital revenue constraints. Asset procurement and construction will be completed in the year 2019/20.

Risks associated with continued operation of the 11kV switchboard beyond end of expected life are being managed by regular condition monitoring of the switchgear. Security arrangements will continue to be managed in the interim by utilising load transfers if necessary for brief periods where the 12MVA AAA security development trigger is reached. Seismic resilience risk has been accepted as tolerable over the short term with all other remaining substations on the EIL network built or strengthened to sufficient resilience levels and should be able to support the Southern substation load if required.

Cost $0.5M – 2.5M 2019/20; CAPEX – System Growth.

Asset Relocation Projects

This budget captures costs for general minor relocation works required such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year.

Under $0.5M per annum on-going; CAPEX – Asset Relocations

Supply Quality Upgrades

On the LV network operation beyond capacity manifests as low voltage experienced by customers during periods of peak loading. This may occasionally require a new transformer site with associated 11kV extension if required. However in most cases replacing LV cables with larger cables will be a more economic option to maintain acceptable voltage for all customers. The minimum standard cable size which provides the existing and spare capacity for expected growth will be used.

An alternative to network upgrade is demand side management however cost incentives to reduce demand are proving ineffective due to the retailers repackaging of line charges into their billing. As EIL's 11kV feeders have high load density supplied over a relatively short distance, low voltage is not seen as an issue on these feeders. Harmonics have not caused any known issues to date.

Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year. The years 2016/17 and 2017/18 have increased budget to manage an increase in upgrades foreseen as the rollout of smart meters on the EIL network progresses and identifies voltage constraints.

Under $0.5M per annum on-going; CAPEX – Quality of Supply.

Network Automation Projects

This budget is to allow implementation of further network automation initiatives on the underground Invercargill network to add additional remote controllable switching points and automation technologies. This will contribute to improvements in reliability and aim to offset the reduction in reliability expected as the cable network is allowed to age back to the optimal average asset life remaining of 50% following the extensive underground programme and other recent or near future capital intensive projects.

This project was initiated last year targeting the overhead Bluff network which sees a relatively high number of faults. The associated field switchgear was installed over the past year however difficulties established communications have meant that the complete solution will be implemented in 2016/17. Automation technology application will target Invercargill starting 2017/18 and continue over the ten year planning horizon.

Under $0.5M per annum on-going; CAPEX – Quality of Supply.

Substation Safety

Arc flash hazards have been identified around MV switchgear at zone substations, presenting a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

A retrofit arc-flash installation is planned to be completed on the Leven Street 11kV switchboard in the 2016/17 year after resource shortages have delayed installation. This involves replacing the switchboard incomer circuit breaker electromechanical relays with modern digital relay incorporating arc flash protection. Optical fibres will be run inside the switchboard to cover all compartments where an arc-flash might occur allowing the incomer relays to cover the entire switchboard. Supporting solutions may include additional PPE requirements, operational controls and protection improvements including retrofit of arc flash detection.

Design was completed between the 2014/15 and 2015/16 years. Installation in 2016/17 will coincide with the installation of the replacement Leven Street RTU which should allow some benefits in terms of installation efficiency.

Cost under $0.5M 2015/16; CAPEX – Other Reliability, Safety and Environmental.

NER Installation at Substations

Neutral Earthing Resistors (NERs) are being installed at each zone substation to limit earth fault currents on the 11kV network. While NERs alone will not ensure network safety they will generally significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs. EIL considers NERs to be effectively a requirement of the EEA guide as when cost is considered to be distributed over all affected earth sites downstream of the zone substation this per site cost is quite low. The extent of work required at individual distribution sites to improve earth effectiveness is therefore reduced making the NER an overall cost effective solution.

Most of the EIL network in Invercargill is now underground which makes other impedance earthing options (installation of a ground fault neutraliser or Peterson coil) uneconomic as the cable network has very high capacitance which these inductive coil devices have to oppose. This means a very large coil would be required and would be many times more expensive than an NER installation. The large cable network does however mean that the entire Invercargill network, which includes the neighbouring TPCL Invercargill areas, creates a very large MEN (multiple earthed neutral) system which essentially interconnects all earths in Invercargill and provides another means to assist in controlling dangerous earth potential rise on the network.

The Bluff network is mostly overhead however Peterson Coils are still many times more expensive than an NER installation. The cost per distribution earth site of the NER is again more cost effective than the otherwise additional upgrades per site that would be required without the NER. Some benefit is gained by the Bluff MEN, however this is much smaller and may include smaller "islands" without the MV cables tying LV MEN systems together as happens in Invercargill.

The more resistance the NER has the greater the safety benefit and the smaller and therefore the lower the cost will be. However at a certain point the discrimination between network fuses and upstream feeder circuit breakers will be lost. Lost discrimination will have a large negative impact on network reliability with some outages being much more widespread so this effectively dictates the minimum NER size that can be installed. Two sizes have been standardised on, with the Spey Street and Leven Street substations requiring larger NERs since they supply larger transformers in the CBD and require higher rated fuses for protection.

The NER's will also provide an additional benefit in limiting damage to faulted equipment and in some situations allow lower rated equipment to be installed, for example light duty cable screens. Apart from reduced earth potential rise, improved general safety around downstream sites is a further benefit as the reduced earth fault levels are far less likely to result in arc-flash or explosion events for the majority of faults.

Two NERs were installed at Spey Street in 2014/15 as part of the new substation construction; one in service and the other as an onsite spare to minimise changeover time in the event of an NER failure. 200A NERs were also installed at each of Racecourse Road and Southern substations in the 2015/16 year while the NER affecting EIL's Bluff network was installed at the Bluff substation in 2015/16 as part of TPCL's roll out of NER installations.

The 2000A NER temporarily installed at Doon Street substation will be relocated to Leven Street substation in 2016/17. All major procurement costs were met in 2015/16. Civil works at Leven Street were initiated in 2015/16 however resource constraints have meant this installation will now be completed in 2016/17.

Under $0.5M 2016/17; CAPEX – Other Reliability, Safety and Environment.

Earth Upgrades

Ineffective earthing may create, or fail to control, hazardous voltage that may occur on and around network equipment affecting safety for the public and for staff. Also other functional requirements may not be met preventing protection systems from operating correctly which may affect safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades.

The analysis to determine what upgrade options are appropriate can be quite complex but essentially it looks to find the best trade-off between cost and risk reduction. Generally in EIL the earthing upgrades required will be minimal with safety being achieved by simple connection to the large urban MEN (multiple earthed neutral) system. However for sites where risk of potential exposure to EPR is high additional measures for example insulating barriers will be required to ensure public safety.

Routine testing is completed five yearly with the entire network tested in one year. Testing is next due in 2017/18.

Cost under $0.5M 2017/18, 2022/23 and five yearly thereafter; CAPEX – Other Reliability, Safety and Environmental.

Unspecified Projects

The unspecified projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low.

$0.5M - $2.5M 2018 per annum onwards; System Growth.

4.4. Distributed Generation Policy

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

- Reduction of peak demand at the Transpower GXP.
- Reducing the effect of existing network constraints.
- Avoiding investment in additional network capacity.
- Making a very minor contribution to supply security where the customers are prepared to accept that local generation is not as secure as network investment.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.

It is also recognised that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset’s capacity.
- Raising voltage above regulated levels.

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and EIL 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.

Despite the benefits noted above there are no distributed generators within EIL's network that have an appreciable effect on development planning.

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 EIL's costs, such as transmission costs or deferred investment in the network, and provided the distributed generation is of sufficient size (greater than 10kW) to provide real benefits, will be recognised and shared.
- Those wishing to connect distributed generation must have a contractual arrangement with a suitable party in place to consume all injected energy – generators will not be allowed to "lose" the energy in the network.

Safety Standards

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

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 EIL. Such metering may need to be half-hourly.
- EIL 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 EIL's own prevailing standards.

4.5. Use of Non-Asset Solutions

As discussed in section Cost Efficiency the company routinely considers a range of non-asset solutions and indeed EIL'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 a reduction of their load instead of investing in additional network assets.

4.6. EIL's Forecast Capital Expenditure

The forecast capital expenditure for EIL is shown in Table 38. These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 38: EIL's Forecast Capital Expenditure

CAPEX: Consumer Connection	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Customer Connections (≤ 20kVA)	61,541	61,541	61,541	61,541	61,541	61,541	61,541	61,541	61,541	61,541
Customer Connections (21 to 99kVA)	49,232	49,232	49,232	49,232	49,232	49,232	49,232	49,232	49,232	49,232
Customer Connections (≥ 100kVA)	110,918	110,918	110,918	110,918	110,918	110,918	110,918	110,918	110,918	110,918
Distributed Generation Connection	2,462	2,462	2,462	2,462	2,462	2,462	2,462	2,462	2,462	2,462
New Subdivisions	45,656	45,656	45,656	45,656	45,656	45,656	45,656	45,656	45,656	45,656
	269,809	269,809	269,809	269,809	269,809	269,809	269,809	269,809	269,809	269,809

CAPEX: System Growth	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Radiator Additions & Zone Sub Tidyup	46,826	-	-	-	-	-	-	-	-	-
Doon Street Reconfiguration	-	-	-	349,236	-	-	-	-	-	-
Southern Substation Upgrades	-	-	-	2,153,109	-	-	-	-	-	-
Unspecified Projects	-	-	-	-	-	874,725	874,725	874,725	874,725	874,725
	46,826	-	-	2,502,345	-	874,725	874,725	874,725	874,725	874,725

CAPEX: Asset Replacement and Renewal	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Underground Substation Replacements	1,211,382	2,396,430	2,396,430	-	-	-	-	-	-	-
Link Box Replacement	540,640	810,960	810,960	54,064	54,064	54,064	54,064	54,064	54,064	54,064
RTU Replacement	108,128	128,402	-	-	151,728	-	-	-	-	-
Power Transformer Refurbishment	-	162,061	-	-	144,698	144,698	-	-	-	-
Racecourse Road Switchboard Replacement	-	-	-	117,720	1,389,096	-	-	-	-	-
Siesmic Remedial Distribution	-	-	-	-	252,880	309,429	309,429	-	-	-
Zone Substation Minor Replacement	3,755	3,755	3,755	3,755	3,755	3,755	3,755	3,755	3,755	3,755
Transformer Replacement - City	237,010	364,145	364,145	364,145	364,145	421,350	421,350	421,350	421,350	421,350
Transformer Replacement - Bluff	-	87,621	87,621	87,621	87,621	87,621	87,621	87,621	87,621	87,621
RMU Replacements	197,508	197,508	197,508	197,508	526,688	526,688	526,688	526,688	526,688	526,688
Reactive 11kV Cable Replacement	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776
Planned 11kV Cable Replacement	-	-	-	-	-	263,344	263,344	263,344	263,344	263,344
General Technical Replacement	50,069	50,069	50,069	50,069	50,069	50,069	50,069	50,069	50,069	50,069
General Dist Replacement - City	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776
General Dist Replacement - Bluff	214,904	177,172	177,172	177,172	177,172	177,172	177,172	177,172	177,172	177,172
LV Board Replacement	27,032	27,032	27,032	27,032	27,032	27,032	27,032	27,032	27,032	27,032
Pillar Box Replacement	15,385	15,385	15,385	15,385	15,385	15,385	15,385	15,385	15,385	15,385
Reactive LV Cable Replacement	62,392	62,392	62,392	62,392	62,392	62,392	62,392	62,392	62,392	62,392
	2,705,758	4,520,485	4,230,022	1,194,416	3,344,277	2,180,551	2,035,854	1,726,425	1,726,425	1,726,425

CAPEX: Asset Relocations	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Relocation Projects	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595
	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595	5,595

CAPEX: Quality of Supply	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Supply Quality Upgrades - City	61,541	61,541	12,138	12,138	12,138	12,138	12,138	12,138	12,138	12,138
Supply Quality Upgrades - Bluff	6,154	6,154	6,154	1,214	1,214	1,214	1,214	1,214	1,214	1,214
Network Automation Projects	27,730	27,730	27,730	27,730	27,730	27,730	27,730	27,730	27,730	27,730
	95,424	95,424	46,022	41,082	41,082	41,082	41,082	41,082	41,082	41,082

CAPEX: Other Reliability, Safety and Enviro	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Earth Upgrades - City	-	12,478	-	-	-	-	12,478	-	-	-
Earth Upgrades - Bluff	-	1,248	-	-	-	-	1,248	-	-	-
Substation Safety	72,812	-	-	-	-	-	-	-	-	-
NER Installations	82,012	-	-	-	-	-	-	-	-	-
	154,824	13,726	-	-	-	-	13,726	-	-	-

Total Capital Expenditure	3,278,236	4,905,039	4,551,448	4,013,246	3,660,763	3,371,762	3,240,791	2,917,635	2,917,635	2,917,635

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 create and maintain the fulfilment of the assets purpose 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 as per a design or network standard and commissioned through a 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 assets 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 is retired from service. Assuming the need remains the asset will be replaced while the retired asset must be disposed of appropriately. This process is outlined in Figure 40 below.

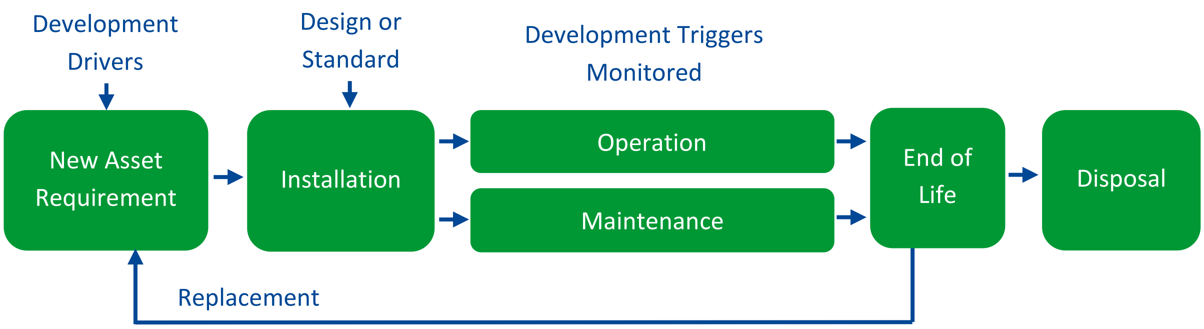

Figure 40: Asset Lifecycle

EIL follows several asset management procedures to manage network assets throughout these lifecycle stages as referenced in Appendix 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 at any point (or gradually) throughout the assets operational life and so may change the viability of maintaining or at end of life 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 whereas standards are used to guide the construction and installation of more regular 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 EIL'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.

Operating EIL's Assets

Operation of EIL's assets predominantly involves doing nothing and 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 doesn't involve any physical modification to the asset, simply a change to the asset's state or configuration.

Operation of the network is effectively the service that EIL'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.

Maintaining EIL's Assets

Maintenance is primarily about replacing consumable components. Many of these components will be designed to "wear out" any number of times 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 41. 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 41 is not simply labelled "time".

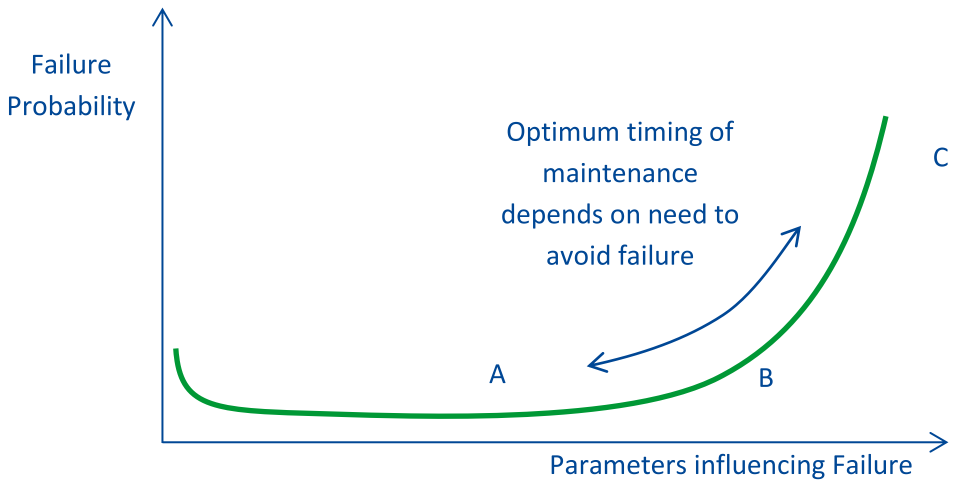

Figure 41: Component Failure

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 EIL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoiding supply interruption. Increasing maintenance costs (labour and consumables) over the asset's lifecycle along with the cost of discarding unused component life must trade-off with the desire to avoid failure. The optimal time for maintenance depends on an assets criticality (impact of failure on customers) and ultimately on how much EIL'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 66/11kV substation transformer may only be operated to point B in Figure 41 and condition will be extensively monitored to minimise the likelihood of supply interruption whilst assets supplying only a few customers such as a 10kVA 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 monitoring 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 monitoring 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).

Replacement and Renewal of EIL'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 required.

Ultimately an asset will reach end of life when it either fails or deteriorates to the point it becomes uneconomic to repair or maintain. This will occur when failure causes significant damage to the overall asset (highly likely at distribution or subtransmission voltages) or when a “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.

Retiring and Disposing of EIL’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 and 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 dependant 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 is noted and may trigger corrective maintenance if economic especially where deterioration can be “nipped in the bud”, for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved) for example pole cracks or 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 not able to cover all assets such as cables buried underground and may be 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 will cause a fault which needs to be repaired.

EIL’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 which are not routine but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults so the basic approach is to inspect these assets and perform preventative maintenance over the most cost effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to repair. 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 39 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 39: 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 and otherwise opportunistic inspection if covers removed for other work. Sheath insulation IR tested. 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 Sub Transmission 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	Sub Transmission 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 (Bucholz, 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 Operation count 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.	Monthly 5 Yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
		Corrective maintenance as required after any concerning inspection or test results.	Non-Periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures, buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Relays recertified by external technicians as regulations require. Otherwise any other equipment visually inspected for anything untoward.	Monthly 5 yearly Non-Periodic
Distribution Network	O/H	Condition 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 and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if visible
	Distributed Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500kVA and larger. Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated. Winding resistances, Insulation resistance for older units if shut down allows. DGA for critical end of life units.	6 monthly or if <150kVA 5 yearly Opportunistic Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge. Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	6 monthly 5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. O/H structures included in distribution	6 monthly

Asset Category	Sub Category	Maintenance Approach	Frequency
		network inspections.	
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting sinking etc. Internal components run to failure and repair. Some opportunistic inspections when opened for other work.	5 yearly
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 40 and forecasts are provided in Table 44 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 40: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Routine Distribution Inspections, Checks & Maintenance	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.	Cost Under $0.5M on-going; OPEX
Minor Work Distribution Inspections, Checks & Maintenance	Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
Routine Technical Inspections, Checks & 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.	Cost Under $0.5M on-going; OPEX
Minor Work Technical Inspections, Checks & Maintenance	Generally reactive work undertaken to correct issues found during the routine technical inspection. Also a general budget for all minor technical work.	Cost Under $0.5M on-going; OPEX
Partial Discharge Survey	Routine partial discharge condition monitoring surveying of subtransmission cables, terminations	Cost Under $0.5M on-going; OPEX

Budget	Description	Expenditure Range/Type
	and equipment to identify abnormal discharge levels before failure occurs.	
Infra-Red Survey	Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc for abnormal heating as indication of poor electrical contact between current carrying components which may lead to voltage quality issues and/or failure of equipment.	Cost Under $0.5M on-going; OPEX
General Substation Maintenance	Routine maintenance at distribution substation assets such as cleaning, paint touch-ups and enclosure repairs.	Cost Under $0.5M on-going; OPEX
General RMU Maintenance	Routine maintenance for Ring Main Units such as cleaning, paint touch-ups and enclosure repairs.	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
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Cost Under $0.5M on-going; OPEX
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	Cost Under $0.5M on-going; OPEX
Customer Connections	Operational portion of expenditure for the customer connections process is captured in this budget.	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

Systemic Issues

EIL has been made aware of a potential systemic weakness in the 33kV oil filled cables which supply Doon and Southern substations. Similar cables on other distribution company's networks have been found showing signs of insulation damage due to weakness in the cable joints allowing movement of the cores with thermodynamic expansion and contraction. Development projects will help mitigate some of the associated reliability concerns and are detailed in Development Planning.

EIL's underground substations have been identified as confined spaces and therefore require special operational procedures to manage the associated risks making these sites burdensome to access and maintain. Despite this risk management a significant level of residual risk remains. Even without these issues the underground nature of these substations and their location in the CBD mean major refurbishment and replacements associated with these sites would cause significant disruption for the public. The additional cost and risk that remains around managing these substations has meant it is appropriate to remove and replace these substations with above ground sites. This replacement programme is detailed in Asset Replacement and Renewal.

Underground link boxes have also been identified as a safety issue regarding potential for arc-flash hazards and are presently being replaced.

EIL's has many oil filled RMUs with operating restrictions in place. Solutions for safe operation are being developed for short term management of the safety issues while avoiding the inconvenience and effect on network reliability currently being experienced. Longer term management of these issues is likely to require early replacement of many RMUs.

There are no other systemic issues presently being investigated. 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 EIL 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 expected 45 year life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole of 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 Development Criteria.

Table 41 sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 41: 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	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.
	Distributed Sub Transmission Voltage Switchgear (ABSs)	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	Major refurbishment for transformers is undertaken when units reach half of their expected life. Replaced after failure causing significant damage that is not economic to repair; most units will be allowed to run to failure to utilise entire lifespan unless failure risk is unacceptable. May be replaced if tank and fittings are deteriorating, spare parts are unavailable and not economic to maintain for aged units. May be scrapped if not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit. Paper, Furan or DGA analysis used to indicate insulation remaining life.
	Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		significant accumulating deterioration or seismic resilience concerns. Bus work and conductors Not economical to maintain. Greater than Standard Life and maintenance required.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Distribution Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Often 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 age or as part of other replacements at site. Units removed from service <100kVA and older than 20yrs are scrapped otherwise tested and if satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	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

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure but security provided by backup plant.

Non-Routine Replacement and Renewal Projects

Replacement and renewal projects that are not ongoing are described in Table 42 and often represent one-off replacement or renewal of significant assets that have reached end of life or a significant miles stone 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.

Table 42: Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
Underground Substation Replacements: EIL owns several underground distribution substations in and around the Invercargill CBD. These substations contain 11kV switchgear, distribution transformers, LV distribution boards and several other minor components. Equipment has now reached end of life at some sites and requires replacement as risk of failure increases to ensure acceptable service levels are maintained. Each underground substation is a fully enclosed space with limited access. They have been deemed “confined spaces” due to the risk of toxic or oxygen deficient atmosphere and the difficulties of rescuing an unconscious person due to an accident or health condition. Extensive measures have been put in place to manage these risks however some residual risk remains and accessing these sites has become rather cumbersome and ultimately expensive. EIL sees that the best option is to relocate these sites above ground and while finding suitable locations within the Invercargill CBD will be difficult it is the only way to eliminate the confined space risks. Negotiating sites within carparks is desirable as this will also help avoid future traffic management in the busy CBD, pavement disruption and pavement reinstatement works (often stylized with paving stones) when working around these sites in future. This programme was initiated in 2014/15 with the first substation replacement completed over the last year. The Kelvin Hotel substation was replaced with an above ground substation in the Southland Times building carpark. A smaller substation was already located at this new site and the replacement substation has a larger capacity to replace and supply the load of both sites. The replacement programme will continue with four underground sites relocated and	CAPEX Cost $0.5-2.5M 2016/17, 2017/18 and 2019/20

Project and Description	Cost and Timing
replaced per year until the remaining twelve underground distribution substations are removed.	
Link-box Replacements: These LV link boxes have been identified as a safety issue due to their below ground arrangement, the nature of having to work above exposed conductors and the potential for items to fall into the link-box creating arc-flash incidents. While the conductors are protected from ground water by a bell arrangement the outer enclosure of the link boxes are often found filled with water making them difficult to access. These link boxes are also aged with significant rusting and the pitch insulation melting indicating insufficient rating at higher load. With regard to the above issues, especially the safety concerns, these below ground link boxes are being replaced with urgency. Consideration is given to rationalising the number of link-boxes on the LV network to provide sufficient switching flexibility as each is identified for replacement. However for the most part the existing link-boxes are providing a necessary function and are simply replaced with an above ground equivalent. The link-boxes are generally shifted a few metres from the pavement to a convenient location to the councils requirements. For example the link-boxes replaced along Esk Street were incorporated into recreational features to minimise clutter and visual impact. This replacement programme began last year with 12 link boxes replaced to date. Approximately 53 underground link boxes remain in the Invercargill CBD with 13 scheduled to be replaced in 2016/17, a further 20 in 2017/18 and the remaining 20 in 2018/19. A portion of the budgeted cost is required to extend cables to a new offset location and associated ground works and reinstatement.	CAPEX Under $0.5M 2016/17, $0.5-2.5M 2017/18 & 2018/19
RTU Replacements: RTUs provide the SCADA interface between PowerNet's System Control room and the devices located at remote substations. They allow remote indication and control for connected devices such as the ability to open and close circuit breakers, view their status and receive alarms (for example a circuit breaker trip). RTUs are a critical part of maintaining service levels on the network as the remote indication and ability remotely operate the network greatly reduces the time to respond to faults on the network. The RTU at the Leven Street zone substation is at the end of its expected life and a fixed time replacement for this equipment is scheduled for the 2016/17 year to avoid increasing probability of a failure which could have a large impact on network reliability due to the loss of indication and ability to control substation equipment. The RTU is Harris D20M which EIL is unable to get support for creating a significant risk if the equipment should fail. A modern RTU based on SEL devices will be utilised in line with EIL's standardisation. As part of this replacement fibre will be installed between Leven Street substation and Spey Street substation (which has fibre communication links back to System Control at Racecourse Road). This is part of a migration away from the copper multicore cable communication medium which is aging and has inherently limited bandwidth. The additional bandwidth afforded by a fibre connection will allow much greater functionality with benefits such as remote access to relay settings and event files, enhanced and more secure protection systems and options for remote video surveillance. Installation of the fibre was started near the end of the past 2015/16 year.	CAPEX Under $0.5M 2016/17,
EIL also have eight mini GPT RTUs located at eight automated distribution substations in the Invercargill CBD. These units are beyond expected end of life and are becoming less reliable. Failure of these RTUs would result in loss of control of network equipment affecting EIL's service levels so full remote control needs to be maintained. Replacement of RTU's with modern units will provide greater reliability and added functionality. All but three of these RTUs will be replaced as part of the underground substation replacements; these three remaining units will be replaced under this budget scheduled for the 2017/18	Under $0.5M 2017/15,

Project and Description	Cost and Timing
year. Again communications will based on fibre media as replacement for the existing copper multicore cable increasing bandwidth and functionality. The fibre installation will be relatively economic making use of existing buried ducts for most of their installation length. The Kingfisher RTU at Racecourse Road substation will be at end of life in 2019/20 and its fixed time replacement is scheduled for this year as per the considerations discussed above for the Leven Street substation RTU.	Under $0.5M 2020/21
Power Transformer Refurbishment: EIL has recently introduced a strategy to refurbish power transformers beyond half of their expected life. This refurbishment is aimed at ensuring the expected life of transformers and potentially extending life to defer replacements to achieve cost efficiencies in maintaining service for EIL's customers. Four of EIL's 23MVA zone substation transformers are beyond their midlife and are therefore due to be refurbished however the ex-Doon Street transformer which is to be relocated to Southern substation will not be refurbished. Furan and paper sample analysis show that this unit's insulation is approaching end of life and therefore the cost of refurbishment is considered uneconomic given the risk of minimal remaining life. The other three transformers due for refurbishment were intended to be deferred until after April 2020 to best manage capital investment in respect of the regulator imposed revenue limits. However the unit at Racecourse Road has advanced rusting and requires more immediate attention to avoid irreparable damage or failure. This unit is now scheduled for refurbishment in 2017/18. The older of the Leven Street units is scheduled for refurbishment in 2020/21 and the Southern substation transformer is scheduled for refurbishment in 2021/22. These refurbishments will catch up EIL's zone substation transformer fleet with this new strategy.	CAPEX Cost Under $0.5M 2017/18, 2020/21 and 2021/22
Racecourse Road Switchboard Replacement: The 11kV switchboard at Racecourse Road substation consisting of 12 circuit breaker cubicles will reach the end of its expected life in the year 2020/21. Its fixed time replacement is scheduled for this year with design costs allowed for in the previous year 2019/20. The fixed time replacement approach is preferred to manage risk of failure as the probability of failure begins to increase beyond its expected life. Failure of the switchboard could have a major impact on network reliability and security, potentially over an extended period depending on the nature of the damage. Replacement will be based on a modern equivalent selected through a tender process to obtain the best price for equipment able to meet the functional requirements for the new switchboard. The number of circuit breakers will be reviewed prior to tendering to ensure to optimum number which supports the desired network service levels for minimum cost.	CAPEX Cost Under $0.5M 2019/20 and $0.5-2.5M 2020/21
Seismic Remedial Distribution: This project will implement seismic remedial solutions at EIL's distribution substations following seismic assessments. Various options will be available depending on the site characteristics and include strengthening of buildings, enclosures or structures or replacement with self-contained freestanding equipment if more economic. Many sites are unique however there are several common "themes" to enclosures used for ground mounted distribution substations and therefore common solutions can be applied to groups of sites. This programme has been deferred until the next price path period (from April 2020) to best manage capital investment in respect of the regulator imposed revenue limits as well as available resource being utilised on higher risk management programmes. The probability of an earth quake in the interim remains low and as the damage from a	CAPEX Cost Under $0.5M 2020/21, 2021/22 and 2022/23

Project and Description	Cost and Timing
credible earthquake in this period is not expected to be catastrophic across the network the risk is considered acceptable. Remedial work will be spread across three years to manage workload; beginning in 2020/21 and being completed in the 2022/23 year.	

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 43 and expenditure forecasts are provided in Table 38 (CAPEX) and Table 44 (OPEX).

Table 43: Replacement and Renewal Programmes

Budget	Description	Expenditure
Zone Substation Minor Replacement	On-going replacement of minor components at zone substations such as LTAC panels and battery banks.	Annual CAPEX Cost Under $0.5M
Transformer Replacement	On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished.	Annual CAPEX Cost Under $0.5M
RMU Replacements	On-going replacement of Ring Main Units as they reach end of life and risk of failure increases at distribution substations to maintain reliability of supply and safety in the vicinity of the substation.	Annual CAPEX Cost Under $0.5M
Reactive 11kV Cable Replacement	On-going reactive replacement of 11kV cables as identified by condition after fault occurrence.	Annual CAPEX Cost Under $0.5M
Planned 11kV Cable Replacement	An ongoing programme to proactively identify and replace 11kV cables as they reach their economic end of life rather than continue to patch repair old cables beyond this point.	Annual CAPEX Cost Under $0.5M (Initiating 2021/22)
General Technical Replacement	On-going replacement of assets other than transformers, RMUs an LV boards as they reach end of life and risk of failure increases at distribution substations to maintain reliability of supply and safety in the vicinity of the substation.	Annual CAPEX Cost Under $0.5M
General Distribution Replacement	On-going replacements of distribution assets other than cables. These are identified through routine inspection.	Annual CAPEX Cost Under $0.5M
LV Board Replacement	Replacement of hazardous old LV distribution boards with modern touch safe boards – on-going for 10 years.	Annual CAPEX Cost Under $0.5M
Link Box Replacement	On-going replacement of above ground link boxes, beyond the priority replacement of the underground link-boxes described above, which have deteriorated with age or have been damaged and are unfit for service/unsafe.	Annual CAPEX Cost Under $0.5M (from 2019/20)
Pillar Box Replacement	On-going replacement of pillar boxes which have deteriorated with age or have been damaged and are unfit for service or unsafe.	Annual CAPEX Cost Under $0.5M
Reactive LV Cable Replacement	On-going replacement of LV cables as identified by condition after fault occurrence.	Annual CAPEX Cost Under $0.5M

Budget	Description	Expenditure
General Distribution Refurbishment	Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	Annual OPEX Cost Under $0.5M
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 OPEX Cost Under $0.5M
Zone Substation Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the substation assets. Covers items like earth sticks, safety equipment, buildings, battery systems etc.	Annual OPEX Cost Under $0.5M
General Technical Refurbishment	Refurbishment works at distribution substations that won't impact on the valuation of the asset. Identified through routine inspection.	Annual OPEX Cost Under $0.5M

5.4. EIL's Forecast Operational Expenditure

The forecast operational expenditure for EIL is shown in Table 44. These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two further categories not described earlier complete EIL's forecasted operational expenditure budget as follows.

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 EIL's expense as required under the Electricity (Hazards from Trees) Regulations 2003. While some customers have received their first free trim, some are disputing the process and additional costs are occurring to resolve the situation. As EIL's network is mostly underground, tree issues are minimal and therefore costs are relatively low. This OPEX cost is budgeted at $1,400 per annum.

Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. This OPEX cost is budgeted at $0.70 million per annum.

Table 44: EIL's Forecast Operational Expenditure

OPEX: Asset Replacement and Renewal	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
General Dist Refurbishment - City	13,506	13,506	13,506	13,506	13,506	13,506	13,506	13,506	13,506	13,506
General Dist Refurbishment - Bluff	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296
Transformer Refurbishment	9,859	9,859	9,859	9,859	9,859	9,859	9,859	9,859	9,859	9,859
Zone Substation Refurbishment	16,405	16,405	16,405	16,405	16,405	16,405	16,405	16,405	16,405	16,405
General Technical Refurbishment - City	43,748	43,748	43,748	43,748	43,748	43,748	43,748	43,748	43,748	43,748
General Technical Refurbishment - Bluff	10,937	10,937	10,937	10,937	10,937	10,937	10,937	10,937	10,937	10,937
	103,752	103,752	103,752	103,752	103,752	103,752	103,752	103,752	103,752	103,752

OPEX: Vegetation Management	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Vegetation Management - City	875	875	875	875	875	875	875	875	875	875
Vegetation Management - Bluff	547	547	547	547	547	547	547	547	547	547
	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422

OPEX: Routine and Corrective Maintenance	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Routine Dist Insp Check & Mtce - City	43,010	43,010	43,010	43,010	43,010	43,010	43,010	43,010	43,010	43,010
Minor Work Dist Insp Check & Mtce - City	54,685	54,685	54,685	54,685	54,685	54,685	54,685	54,685	54,685	54,685
Routine Dist Insp Check & Mtce - Bluff	7,218	7,218	7,218	7,218	7,218	7,218	7,218	7,218	7,218	7,218
Minor Work Dist Insp Check & Mtce - Bluff	21,874	21,874	21,874	21,874	21,874	21,874	21,874	21,874	21,874	21,874
Earth Testing - City	-	15,908	-	-	-	-	15,908	-	-	-
Earth Testing - Bluff	-	12,727	-	-	-	-	12,727	-	-	-
Routine Tech Insp Check & Mtce - City	147,869	147,869	147,869	147,869	147,869	147,869	147,869	147,869	147,869	147,869
Minor Work Tech Insp Check & Mtce - City	166,850	166,850	166,850	166,850	166,850	166,850	166,850	166,850	166,850	166,850
Routine Tech Insp Check & Mtce - Bluff	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236	1,236
Minor Work Tech Insp Check & Mtce - Bluff	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253
Partial Discharge Survey	49,216	49,216	49,216	49,216	49,216	49,216	49,216	49,216	49,216	49,216
Infra Red Surveys	5,377	5,377	5,377	5,377	5,377	5,377	5,377	5,377	5,377	5,377
General Substation Maintenance	34,998	34,998	34,998	34,998	34,998	34,998	34,998	34,998	34,998	34,998
General RMU Maintenance	200,002	200,002	200,002	200,002	200,002	200,002	200,002	200,002	200,002	200,002
General Zone Substation Maintenance	32,811	32,811	32,811	32,811	32,811	32,811	32,811	32,811	32,811	32,811
Supply Quality Checks - City	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253
Supply Quality Checks - Bluff	1,127	1,127	1,127	1,127	1,127	1,127	1,127	1,127	1,127	1,127
Spares Checks and Minor Maintenance	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094	1,094
Customer Connections	23,514	23,514	23,514	23,514	23,514	23,514	23,514	23,514	23,514	23,514
	795,387	824,023	795,387	795,387	795,387	795,387	824,023	795,387	795,387	795,387

OPEX: Service Interruptions and Emergenci	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Incident Response Dist - City	260,809	260,809	260,809	260,809	260,809	260,809	260,809	260,809	260,809	260,809
Incident Additional Time Dist - City	82,027	82,027	82,027	82,027	82,027	82,027	82,027	82,027	82,027	82,027
Incident Response Dist - Bluff	128,217	128,217	128,217	128,217	128,217	128,217	128,217	128,217	128,217	128,217
Incident Additional Time Dist - Bluff	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281
Incident Response Tech - City	43,868	43,868	43,868	43,868	43,868	43,868	43,868	43,868	43,868	43,868
Incident Additional Time Tech - City	166,723	166,723	166,723	166,723	166,723	166,723	166,723	166,723	166,723	166,723
Incident Response Tech - Bluff	12,359	12,359	12,359	12,359	12,359	12,359	12,359	12,359	12,359	12,359
Incident Additional Time Tech - Bluff	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253	2,253
	699,538	699,538	699,538	699,538	699,538	699,538	699,538	699,538	699,538	699,538

Network Operational Expenditure Total	1,600,099	1,628,734	1,600,099	1,600,099	1,600,099	1,600,099	1,628,734	1,600,099	1,600,099	1,600,099

System Operations and Network Support	680,626	696,456	732,688	732,688	732,688	732,688	732,688	732,688	732,688	732,688
Business Support	2,418,923	2,462,920	2,461,508	2,461,508	2,461,508	2,461,508	2,461,508	2,461,508	2,461,508	2,461,508
Non-Network Operational Expenditure	3,099,549	3,159,376	3,194,196	3,194,196	3,194,196	3,194,196	3,194,196	3,194,196	3,194,196	3,194,196

Operational Expediture Total	4,699,648	4,788,110	4,794,295	4,794,295	4,794,295	4,794,295	4,822,930	4,794,295	4,794,295	4,794,295

6. Risk Management

Risk is seen as any potential but uncertain occurrence that may impact the achievement of objectives and ultimately the value of EIL's business. EIL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. This section examines EIL'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

EIL 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 EIL's asset management strategies also, directly or indirectly, incorporate risk management (see Strategy and Delivery).

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 EIL'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 EIL's risk to acceptable levels with decision making around EIL'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

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 EIL faces, especially following events which may affect local networks or other catastrophic events which might have global impact, or otherwise when there is a change in regulations which may require risk to be considered in greater detail.

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 45 and Table 46 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 45: 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 KPIs due to matters under PowerNet's control.	Significant breaches of an important reliability KPIs due to matters under	Repeat breaches of reliability KPIs due to matters under PowerNet's control	Repeat long term breaches of reliability KPIs due to matters under PowerNet's

Consequence:	Very Low	Low	Moderate	High
		PowerNet's control.	(or perceived by stakeholders to be under PowerNet's control).	control (or perceived by stakeholders to be under PowerNet's control).
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 46: 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

Risk Ranking

Together consequence and probability give an overall measure of a risk. Table 47, 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 47: 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

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 48 summarises the types of treatment options that should be considered for any risk, ordered by effectiveness for the control of risk.

Table 48: 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 elimination is considered to be 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.

Deciding on the most appropriate treatment option may be obvious, for example a low cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation, however deciding between high cost effective treatments and low cost but less effective treatments may be difficult. Choosing the least “cost” option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe is the desired outcome and requires careful judgement of all the factors involved.

Good risk management recognises that limited resources are available 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 adjusting available resources 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. This represents an example where adjustment of the cost/staffing balance may be required.

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 shape existing network rather than only applying to new assets installed.

6.3. EIL's Asset Management Risk

Asset management related risks that have been identified for EIL 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.

Physical

The following physical risks have been identified with Table 50 and Table 49 summarising their quantification and treatment responses:

- 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.
- Earthquake – no recent history of major damage. The November 2004 7.2 Richter scale quake 240 km south-west of Te Anau caused no damage to the network. Although recent earthquakes in Christchurch have proven that large and unexpected events may occur and have significant impact on the network.
- Tsunami – maybe triggered by large off shore earthquake.
- 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.

Table 49: 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 lines designed to AS/NZS 7000:2010
Power Transformer	Unlikely	Low to medium	• At dual power transformer sites, one unit can be removed from service due to fault or maintenance

Event	Likelihood	Consequence	Responses
			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[4] and IR[5]. • 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.
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 five minutes. • If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Master-station	Very Unlikely	Low	• Continue to operate as a Dual Redundant configuration, with four operator stations. This requires both Servers to fail before service is lost. • Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Unlikely	Medium	• Provide backup between EIL and TPCL ripple injection plants at Invercargill. • Manually operate plant with test set if SCADA controller fails.

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.

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

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

Table 50: 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 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. • Maintain fire alarms in buildings.

Safety & Environmental

The following safety and environmental risks have been identified with Table 51 summarising 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
- Underground – safety risks amplified by the close proximities and confined space around underground assets
- 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 51: 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
Underground	Unlikely	High	• De-energise substation before manual switching within substation
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met
Staff Error	Possible	High	• Standardised procedures • Training

Event	Likelihood	Consequence	Responses
			• Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Medium to High	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Alarms on underground sub hatches • Standardised exit procedures in 3rd party bldg • Above ground sub clearances to AS2067 s5 • Design to avoid climbing aids etc.

Human

The following human related risks have been identified with Table 52 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 52: 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.
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 below.
Cyber Attack	Very Unlikely	High	• Secure communications links • Analyse and remove vulnerabilities • Review and apply industry best practice

External Factors

The following external factor risks have been identified with Table 53 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 53: External Factor Event Risks and Responses

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

Weather

The following weather related risks have been identified with Table 54 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 – experience of 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again.

Table 54: Risk Associated with Weather Events and Responses

Event	Likelihood	Consequence	Responses
Wind	Possible	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies wind loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.
Snow	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Design standard specifies snow loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.

			• If access is limited then external plant is hired to clear access or substitute.
Flood	Unlikely	Low	• Impact is reduced by undergrounding of lines. • Transformers and switchgear in high risk areas to be mounted above the flood level. • Zone substations to be sited in areas of very low flood risk.

Corporate

The following corporate risks have been identified with Table 55 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 EIL'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 55: 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
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. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

6.4. Emergency Response and Contingency

The following tactics have been or are being implemented to manage risk for EIL (especially for HILP events):

- Align asset design with current best practice
- Regular inspections to detect vulnerabilities and potential failures
- Remove assets from risk zone
- Build appropriate resilience into network assets
- Provide redundancy of supply to large customer groups
- Involvement with the local Civil Defence
- Prepare practical response plans
- Operate a 24hr control centre

Additionally EIL has the following specific contingencies in place through its management company PowerNet.

PowerNet Business Continuity Plan

PowerNet must be able to continue in the event of any serious business interruption. Events causing interruption can range from malicious acts through damaging events, to a major natural disaster such as an earthquake. PowerNet has developed a Business Continuity Plan which has the following principal objectives:

- Eliminate or reduce damage to facilities, and loss of assets and records.
- Planning alternate facilities.
- Minimise financial loss.
- Provide for a timely resumption of operations in the event of a disaster.
- Reduce or limit exposure to potential liability claims filed against the Company, its Directors and Staff.

In developing the business continuity plan each business unit identified their key business functions and prioritised them according to their criticality and the timeframes before their absence would begin to have a major impact on business functions. Where practicable continuity plans have been developed in line with each critical business function and preparation undertaken where appropriate to allow continuity plans to be implemented should they be required.

PowerNet Pandemic Action Plan

PowerNet must be able to continue in the event of a breakout of any highly infectious illness which could cause significant numbers of staff to be unable to function in their job. The plan aims to manage the impact of an influenza type pandemic on PowerNet’s staff, business and services through two main strategies:

- Containment of the disease by reducing spread within PowerNet achieved by reducing risk of infected persons entering PowerNet's premises, social distancing, cleaning of the work environment, managing fear, management of cases at work and travel advice.
- Maintenance of essential services if containment is not possible achieved through identification of the essential activities and functions of the business, the staff required to carry out these tasks and special measures required to continue these tasks under a pandemic scenario.

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 a transformer was borrowed from TPCL to reinstate a firm supply following failure of a transformer at a critical CBD zone substation.

Network Operating Plans

As contingency for major outages on the EIL network PowerNet holds network operating plans for safe and efficient restoration of services where possible. For example a schematic based switching plan and accompanying operating order detailing steps required to restore supply after loss of a zone substation.

Insurance

EIL 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

Capital Expenditure

Table 56: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2014/15 ($k)	Actual 2014/15 ($k)	Variance
Consumer Connection	200	27	-86.7%
System Growth	7,823	6,739	-13.9%
Asset Replacement and Renewal	2,317	1,604	-30.8%
Asset Relocations	6	-	-100.0%
Quality of Supply	122	92	-24.4%
Legislative and Regulatory	-	-	-
Other Reliability, Safety and Environment	156	134	-14.0.0%
Capital Expenditure on Network Assets	**10,624**	**8,596**	**-19.1%**

Capital works was under budget due to;

- Customer Connections – 87% underspent on customer connections as rate of new connections was lower than typical.
- System Growth – 14% underspent due to delays in securing specialist design affecting project sequencing and re-evaluation of most economic options.
- Asset Replacement and Renewal (including Quality of Supply + Legislative and Regulatory) – 31% underspent with inspections identifying limited work and reactive budgets not required. Seismic remediation delayed due to assessment quality.
- Asset Relocations – 100% underspent due to reactive budget not required.
- Reliability, Safety and Environment – 14% underspent due to design quality delays and resourcing constraints.

Operation Expenditure

Table 57: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2013/14 ($k)	Actual 2013/14 ($k)	Variance
Asset Replacement and Renewal	716	524	-47.2%
Vegetation Management	1	3	88.0%
Routine and Corrective Maintenance and Inspection	1,051	659	-37.3%
Service Interruptions and Emergencies	150	79	-26.8%
Operational Expenditure on Network Assets	**1,918**	**1,265**	**-34.1%**

Maintenance was over budget due to;

- Asset Replacement and Renewal – 47% underspent with inspections identifying limited work and reactive budgets not required.
- Vegetation Management – 88% overspent with reactive work higher than expected.
- Routine and Corrective Maintenance and Inspection – 37% underspent with reactive work lower than expected. Scope for oil cable maintenance modified with project work capitalised.
- Service Interruptions and Emergencies – 27% underspent with reactive work lower than expected.

7.2. Service Level Performance

Reliability

Table 58 displays the target versus actual reliability performance on the network. For the 2013/14 year the overall network performance was very good, with SAIFI 21% under target and SAIDI 3% over target. These results were well within the Commerce Commissions supply quality limits.

Table 58: Performance against Primary Service Targets

	2014/15 AMP Target	2014/15 Actual
SAIFI	1.00	0.79
SAIDI	40.0	41.3

Targets are based on averages over the previous few years and due to the reliability of the network have been set very low. This, however, means single events have the potential to have a significant impact on reliability performance as was the case in the 2011/12 year when a human error incident resulted in a single fault affecting multiple feeders and being difficult to locate.

Customer Satisfaction

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. EIL 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). The few forms received over recent years were positive and indicated customers were satisfied with the service during the process of their new connections.

The customer engagement survey conducted by phone does reliably provide sufficient feedback to understand customer satisfaction regarding a range of aspects around their supply services. Statistics are also recorded for any customer complaints received. Table 59 shows the 2014/15 results for the service levels that EIL have set targets for.

Table 59: 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: Q4(b)}	>90%	67%
	Information supplied was satisfactory {CES: Q8(b)}	>90%	100%
	PowerNet first choice to contact for faults {CES: Q6}	>25%	19%
Voltage Complaints	Number of customers who have made voltage complaints	<10	5
	Number of customers having justified voltage quality complaints	<3	4
Planned Outages	Provide sufficient information {CES: Q3(a)}	>75%	91%
	Satisfaction regarding amount of notice {CES: Q3(c)}	>75%	100%
	Acceptance of max of one planned outage every two years {CES: Q1}	>50%	95%
	Acceptance of planned outages lasting two hrs on average {CES: Q2}	>50%	91%

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

The percentage of customers who were satisfied that their supply was restored within a reasonable amount of time following an unexpected outage was 67% which was below the target of 90%. However 26% indicated that they didn't know or were unsure which may indicate that they were reasonably satisfied as most people might recall a negative experience; only 7% indicated that they felt restoration time was unacceptable. All customers felt the information supplied to them when enquiring about an outage was satisfactory which is a great result. Only 19% of customers surveyed indicated that PowerNet would be their first choice to contact if wanting to report or enquire about a fault which is below EIL's target of 25%. However 61% of respondents said they would not call anyone while a further 11% would take other approaches such a contacting a friend or neighbour. Therefore of those attempting to contact the appropriate authority, about 68% would contact PowerNet which is considered a great result.

Four customers made voltage complaints that were found to be justified. This is unfortunately above EIL's target of less than three complaints. Performance against the remaining secondary service levels around planned outages performed better than the targets set for 2014/15.

Customer Consultation

A face to face survey using a survey company was undertaken with six key clients. Interviewees generally felt PowerNet had a very positive image in the community however there was a perception with some that PowerNet has quite a low profile. It was generally perceived that PowerNet has its customer's best interests at heart however some felt they were unable to comment on this due to lack of visibility.

Customers consistently ranked continuity of supply as the most important aspect of their provided network service and indicated that PowerNet performed very well in this regard; all indicated either nine or ten out of ten except for one customer in Bluff who indicated six to seven out of ten. Otherwise customers indicated prompt restoration of supply, sufficient notice of planned interruptions, cost of supply, and supply quality were important aspects of their network services. Again customers indicated that they were very satisfied with these aspects and the overall service from PowerNet. Some businesses expressed a desire for more proactive and regularly initiated contact from PowerNet staff to make them more aware of pricing and reliability options while others commented that they would prefer to initiate contact with PowerNet themselves.

Network Efficiency

Table 60: Performance against Efficiency Targets

Measure	2014/15 Target	2014/15 Actual
Load factor	> 50%	51%
Loss ratio	< 5.0%	5.6%
Capacity utilisation	> 45%	40%

Load factor was slightly better than the target while loss ratio and capacity utilisation did not quite achieve the targets.

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 and the longer term average is about 5%. New smart meters will allow better analysis and monitoring.

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. EIL's capacity utilisation compares very well with other distribution businesses.

Financial Efficiency

Table 61: Performance against Financial Targets

Measure	2014/15 Target	2014/15 Actual
OPEX/RC	3.89%	3.09%
Indirect Cost per Customer	$123.46	$113.58

EIL's financial efficiency results were good for 2014/15 with the ratio OPEX/RC well below target and Indirect Costs per Customer comfortably below target.

7.3. AMMAT Performance

EIL understands the foundations of good asset management practice and generally looks to implement each aspect, however often implementation is not systematic and therefore may not always be consistent or applied to all potential areas of benefit. In scoring EIL's asset management practice against the Asset Management Maturity Assessment Tool (AMMAT) this results scores from '1' to '3' but with a typical score of '2' as shown in Figure 42.

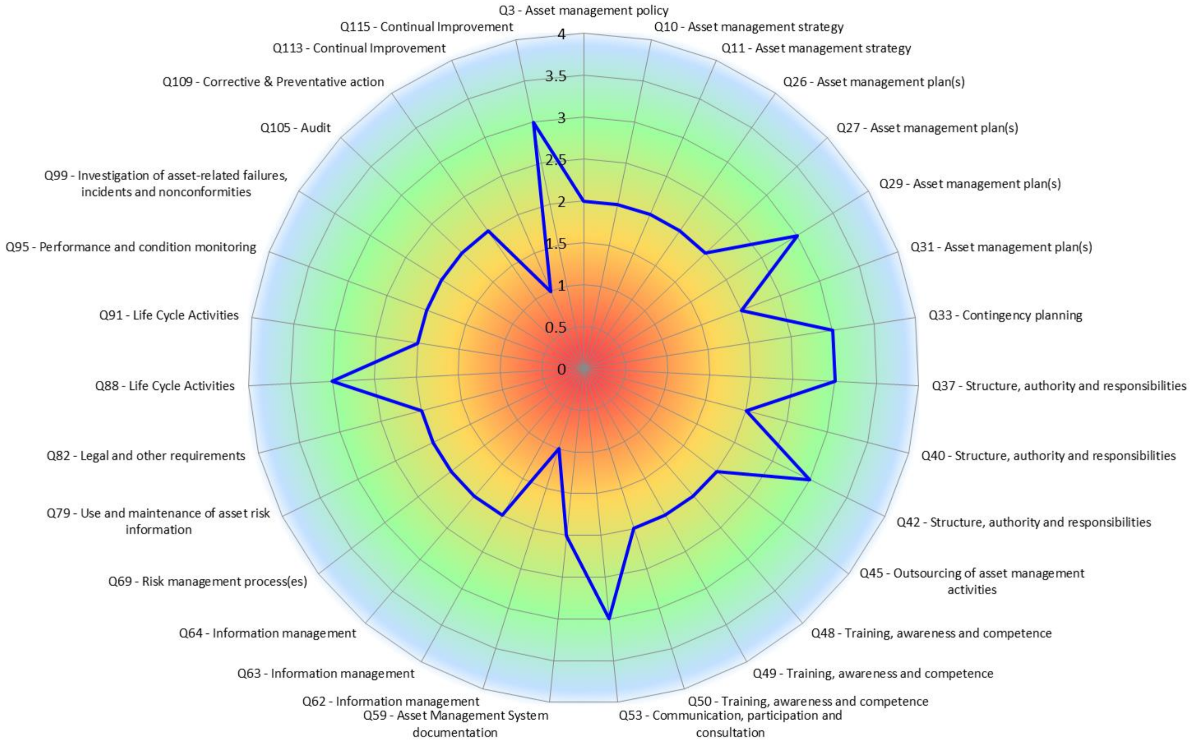

Figure 42: EIL's Asset Management Maturity Assessment Tool Scores

The AMMAT is based on a selection of the questions asked in PAS-55 intended to prompt consideration of performance against a number of facets of asset management practice. Each question can be scored from '0' to '4' and each question has a series of answers to describe what is required to achieve each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

7.4. Gap Analysis and Planned Improvements

AMMAT

For a distribution company of EIL's size a score of '2' for many of the asset management functions is considered appropriate. However as PowerNet provides EIL's asset management services as well as providing this service across other networks, EIL believes that some improvements are realisable and appropriate. EIL therefore believes a score of '3' is desirable as a long term goal for each of the AMMAT functions and that improvements made over time would be generally in line with EIL's asset management and corporate strategies, ultimately supporting the achievement of EIL's asset management objectives.

Of the 30 questions posed in the AMMAT, seven scores of '3' have been determined across the areas of Asset Management Policy, Asset Management Plans, Contingency Planning, Structure Authority and Responsibilities, and Communication, Participation and Consultation. For the remaining questions there is room for improvement, especially with two questions assessed as '1' in the areas of Continual Improvement and Information Management.

While there have been no changes in score since the previous AMP, the following improvements have been made:

- This latest version of EIL'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 aid the AMP in being further embedded in EIL'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 PowerNet and is relevant for EIL's Bluff network and remaining overhead line in Invercargill's industrial regions. 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.
- EIL has adopted the Incident Cause Analysis Methodology (ICAM) approach to investigating safety incidents but has been utilised where other significant incidents have occurred. 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.
- EIL 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 also look 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 EIL's 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 EIL'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.

  EIL 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.

Capital and Maintenance Works

The initiatives above will improve efficiency for capital and maintenance project delivery and support consistent performance against delivery EIL's AWP.

In addition EIL's Amalgamation of EIL's network management company PowerNet and its previous field service contracting companies has improved relationships and communication between planning and field staff. More efficient work practices are being realised and expected to continue. The amalgamated company PowerNet has also employed additional technical field staff to extend the in-house field services concept to further realise efficiencies. This should help increase productivity and with some additional resource EIL should be better placed to deliver the planned projects.

Long term relationships with external contractors are being maintained so they can more confidently build their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

Reliability

On the whole reliability of the EIL network is very good and the SAIDI and SAIFI results for 2014/15 were well within targets set. EIL will look to control the impact of events that might incur large customer-minute totals primarily by increasing the number of remotely controlled devices on the network to speed isolation of faulty sections and restoration of supply to healthy sections. The exposed overhead network in Bluff has been targeted for improvements and completion of the network automation project in Bluff will achieve a significant improvement in the network's reliability.

EIL'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. Again the initiatives noted as improvements under the AMMAT will assist with the improvement of reliability by enhancing EIL's maintenance practices.

Efficiency

Load factor is low compared to other distribution businesses and could be better however load factor has always been difficult to improve on the network and Transpower's current pricing methodology has caused a decrease in this measure. The introduction of smart meters in future years is expected to provide some additional leverage to influence customer's consumption behaviour.

Losses and capacity utilisation are not specifically being targeted for improvement except for selecting efficient and optimally sized assets when required for network development or replacements.

8. Capability to Deliver

EIL 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 EIL 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 EIL's asset management activities lie with the detailed processes and systems that reflect EIL's thinking, manifest in EIL's policies, strategies and processes and ultimately shape the nature and configuration of EIL's fixed assets. The hierarchy of data model shown in Figure 43 describes the typical sorts of information residing within EIL's business (including in PowerNet employees brains).

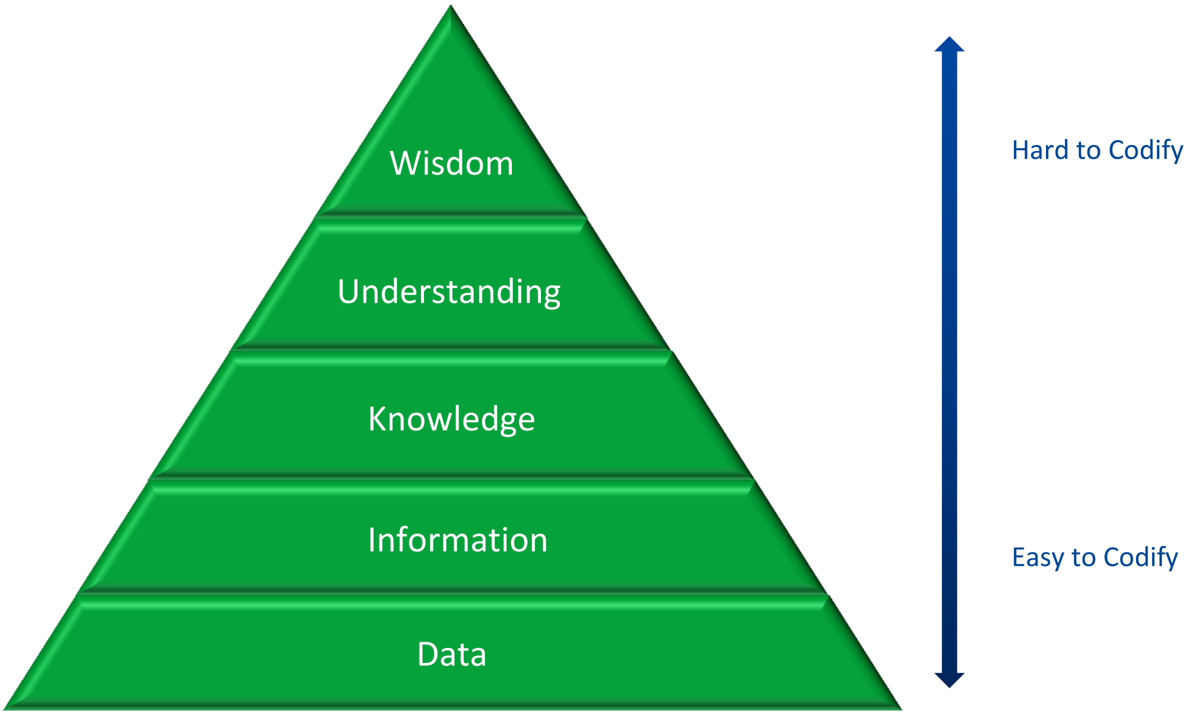

Figure 43: Hierarchy of Data

- The bottom two layers 'Data' and 'Information' of the hierarchy tend to relate strongly to EIL's asset and operational data and the summaries of this data that form one part of EIL'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 43 it is generally hard to codify these things, hence correct application is heavily dependent on skilled and experienced people.

Asset Management Systems

EIL 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 EIL 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 EIL'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. This is called knowledge and probably 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 wrong outcomes. The roles and interaction of each component of the hierarchy are incorporated in Figure 44 which provides a high level summary of EIL's asset management processes and systems.

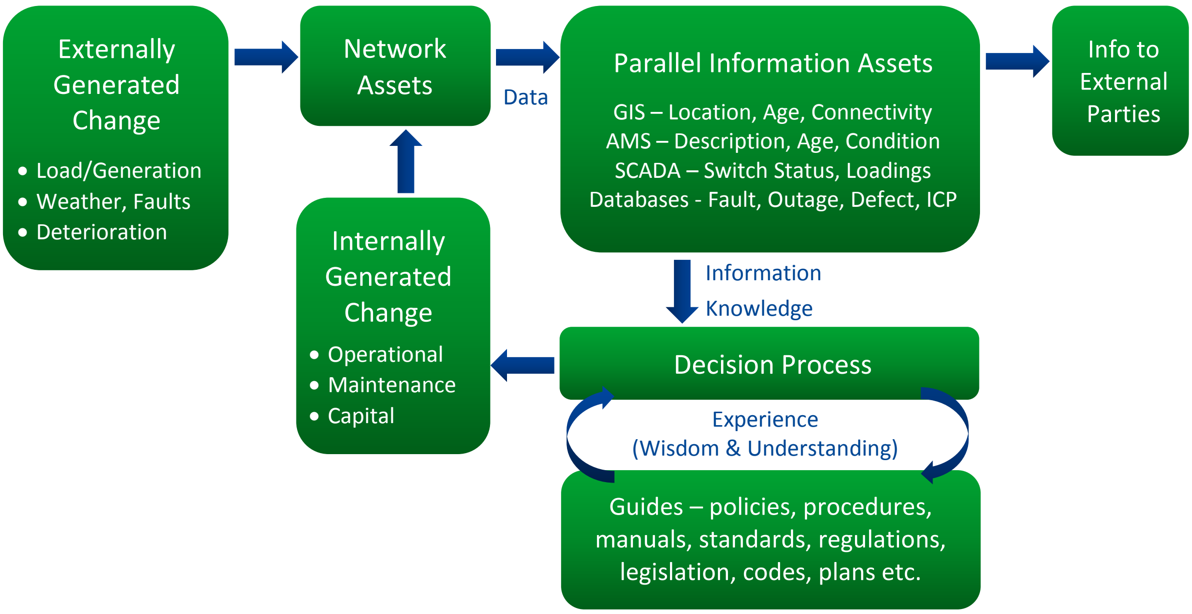

Figure 44: Key information systems and processes

Processes and Documentation

EIL's key processes and systems are based around the key lifecycle activities defined in Figure 44, 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 EIL'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 obvious.

The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 1:

- Operating Processes and Systems
- Maintenance Processes and Systems
- Renewal Processes and Systems
- Up-sizing or Extension Processes and Systems
- Retirement Processes and Systems
- Performance Measuring Processes
- Other Business Processes

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

Documents and Control Reviews

Each document is controlled by an owner at management level who is given responsibility for the documents 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 and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals effected.

Asset Management Tools

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

The **Asset Management System (AMS)** stores EIL'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' 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 EIL's AMS Maximo is considered better suited to EIL's needs, providing greater functionality and helping streamline administration of EIL's maintenance practices.

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 EIL.

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 EIL 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.

Outage, Fault 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 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 therefore 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 EIL Board 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 have the potential to, 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.

Data Control, Improvement and Limitations

EIL'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 63% of 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 and for all other data, for example electrical connectivity, thorough processes, peer reviews and well trained staff are used to ensure data entry quality is very good. Key process improvements will include more timely as-builts with PowerNet staff taking GPS[6] 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 discovered 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.

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 apart from these data copying interfaces and 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 62 provides a summary for the completeness of EIL's data.

Table 62: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion & GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion & GIS update
GIS	Age	Poor	Pole ages not available for 63%
Condition Assessment	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair

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

System	Parameter	Completeness	Notes
Database			
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

EIL'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 45.

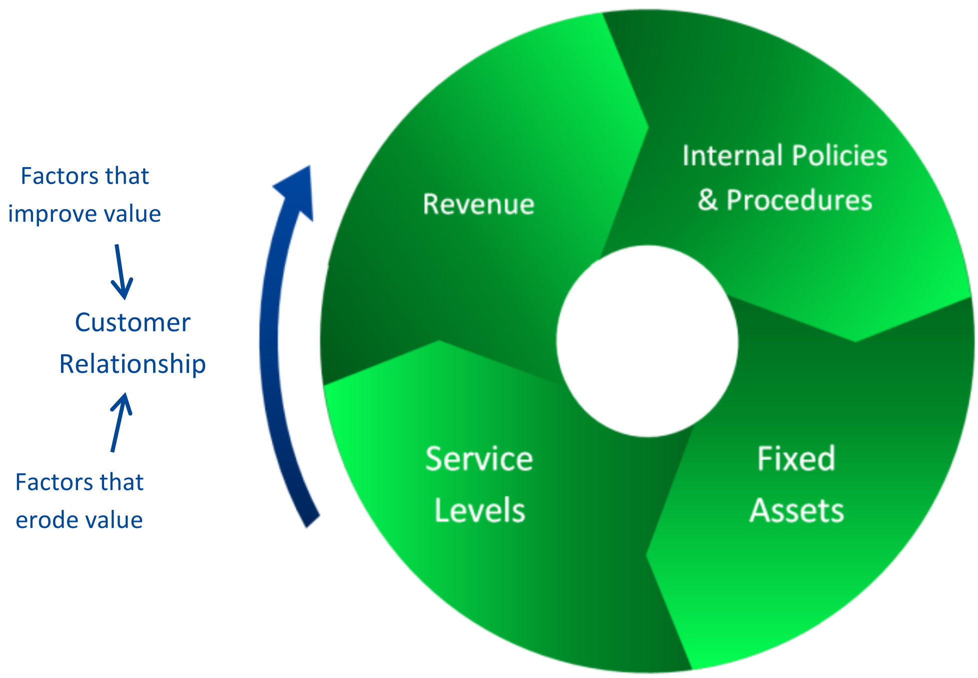

Figure 45: Customer Interface Model

Revenue

EIL's money comes primarily from the retailers who pay for the conveyance of energy over EIL'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) EIL 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 EIL to avoid new capital on its balance sheet, but perhaps more importantly also allows EIL to treat any increased Transpower charges as a pass-through cost

Expenditure

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

Influences the Value of Assets

An annual independent telephone 'Customer Engagement Survey' is undertaken in September each year and consistently indicates EIL'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 EIL'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 EIL 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 EIL's asset value are shown in Table 63 below:

Table 63: Factors influencing EIL's asset value

Factors that increase EIL's asset value	Factors that decrease EIL'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 EIL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

Depreciating the Assets

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 EIL 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.

PowerNet's internal field services is a 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 EIL'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 that EIL's development and maintenance requirements are on-going into the future.

Appendix 1 – 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
Entry to EIL Underground Substations	PNM-076
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

Appendix 2 – Customer Engagement Questionnaire

PowerNet Customer Engagement
Telephone Questionnaire 2015
Electricity Invercargill Limited

Phone	Date	Interviewer
Good afternoon/evening my name is _____. I am conducting a brief customer survey on behalf of PowerNet. 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 PowerNet is?	Yes	**1**	
	No	**2**	*Go to Q 1(c)*

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

Question 1(b): Using a 1 to 5 rating scale where 1 is Poor and 5 is Excellent can you rate the performance of PowerNet 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): PowerNet maintains the local electricity lines and substations that supply power to your premises.

Question 2: PowerNet is proposing on average one planned interruption to your power supply every two years 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 3*
	No	**2**	*Go to Q 2(a)*
	Don't know/unsure	**3**	*Go to Q 3*

Question 2(a): How many years between planned interruptions do you consider to be more reasonable?	3 years	**1**
	4 years	**2**
	5 years	**3**

Question 3: Such planned interruptions will on average last up to two hours each. Do you consider this amount of time 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): What length of time would you consider to be more reasonable? *(Specify hours)*	30 min	**1**	
	1 hours	**2**	
	$1^{1}/_{2}$ hours	**3**	

Question 4: Have you received advice of a planned electricity interruption during the last 6 months?	Yes	**1**	*Go to Q 4(a)*
	No	**2**	*Go to Q 4(e)*
	Don't know/unsure	**3**	*Go to Q 4(e)*

Question 4(a): Were you satisfied with the amount of information given to you about this planned interruption?	Yes	**1**	*Go to Q 4(c)*
	No	**2**	*Go to Q 4(b)*
	Unable to recall	**3**	*Go to Q 4(c)*

Question 4(b): What additional information would you have liked?

Question 4(c): Do you feel that you were given enough notice of this planned interruption?	Yes	**1**	*Go to Q 4(e)*
	No	**2**	*Go to Q 4(d)*
	Don't know/unsure	**3**	*Go to Q 4(e)*

Question 4(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 4(e): Does it matter to you what day or time a planned outage takes place?	Yes	**1**	
	No	**2**	*Go to Q 5*

Question 4(f): Which would you prefer?	Mornings	**1**
	Afternoons	**2**
	Evenings	**3**
	Other	**4**
	Weekdays	**1**
	Weekends	**2**
	Other	**3**
	Don't know	**4**

Question 5: Have you had an unexpected interruption to your power supply during the last 6 months?	Yes	**1**	
	No	**2**	*Go to Q 6*
	Unable to recall	**3**	*Go to Q 6*

Question 5(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**
	$1^{1}/_{2}$ hours	**3**	12 hours	**7**
	2 hours	**4**	Don't know	**8**
			Other	**9**

Question 5(b): Do you consider your electricity supply was restored within a reasonable amount of time?	Yes	**1**	*Go to Q 6*
	No	**2**	*Go to Q 5(c)*
	Unable to recall	**3**	*Go to Q 6*

Question 5(c): What do you consider would have been a more reasonable amount of time? *(Specify hours/days)* *(Do not prompt)* **Go to Q7**	30 minutes	**1**	$1^1/_2$ hours	**4**
	45 minutes	**2**	2 hours	**5**
	1 hour	**3**	Other	**6**

Question 6: 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**
	$1^1/_2$ hours	**9**	Other	**18**

Question 7: Currently there is an average of one interruption every two years. If this was reduced to one interruption every three years 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 7(a): If PowerNet were to reduce your bill by $10 per month, would you be happy that the number of interruptions increased to one every year?	Yes	**1**
	No	**2**
	Don't know/unsure	**3**

Question 8: Do you intend to purchase an electric car in the next 12 months?	Yes	**1**
	No	**2**
Question 8(a): Or solar panels		
	Yes	**1**
	No	**2**

Question 9: 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**
	Genesis Energy	**6**
	No one	**7**
	Other	**8**

Question 9(a): Have you made such a call within the last 6 months?	Yes	**1**	
	No	**2**	*Go to Q 10*
	Unable to recall	**3**	*Go to Q 10*

Question 9(b): Were you satisfied that the system worked in getting you enough information about the supply interruption?	Yes	**1**	*Go to Q 9(d)*
	No	**2**	*Go to Q 9(c)*
	Don't know/unsure	**3**	*Go to Q 9(d)*

Question 9(c): What, if anything, do you feel could be done to improve this system?	

Question 9(d): Were you satisfied with the information that you received?	Yes	**1**	*Go to Q 10*
	No	**2**	*Go to Q 9(e)*
	Don't know/unsure	**3**	*Go to Q 10*

Question 9(e): What, if anything, do you feel could be done to improve this information or the way in which it is delivered?

Question 10: 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 11: Are you aware of PowerNet's 0800 faults number?	Yes	**1**
	No	**2**

Question 12: Finally, do you have any comments or suggestions about anything to do with PowerNet 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. – Capital Expenditure Forecast

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2016 – 31 March 2026

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
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	**11a(i): Expenditure on Assets Forecast**		$000 (in nominal dollars)										
10	Consumer connection		592	270	275	281	286	292	298	303	308	314	319
11	System growth		3,110	47	-	-	2,655	-	965	982	1,000	1,017	1,035
12	Asset replacement and renewal		2,319	2,706	4,615	4,399	1,267	3,622	2,405	2,286	1,973	2,008	2,042
13	Asset relocations		6	6	6	6	6	6	6	6	6	7	7
14	Reliability, safety and environment:												
15	Quality of supply		82	95	97	48	44	44	45	46	47	48	49
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		237	155	14	-	-	-	-	15	-	-	-
18	**Total reliability, safety and environment**		319	250	111	48	44	44	45	62	47	48	49
19	**Expenditure on network assets**		6,345	3,278	5,008	4,734	4,258	3,965	3,719	3,639	3,335	3,393	3,452
20	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**		6,345	3,278	5,008	4,734	4,258	3,965	3,719	3,639	3,335	3,393	3,452
22													
23	*plus* Cost of financing		-	1	2	3	4	5	6	7	8	9	10
24	*less* Value of capital contributions		178	81	83	84	86	88	89	91	93	94	96
25	*plus* Value of vested assets		-	1	2	3	4	5	6	7	8	9	10
26													
27	**Capital expenditure forecast**		6,168	3,199	4,929	4,655	4,180	3,887	3,642	3,563	3,258	3,317	3,376
28													
29	Assets commissioned		5,812	3,304	4,929	4,655	4,431	3,887	3,642	3,563	3,258	3,317	3,376

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		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
32			$000 (in constant prices)										
33	Consumer connection		592	270	270	270	270	270	270	270	270	270	270
34	System growth		3,110	47	-	-	2,502	-	875	875	875	875	875
35	Asset replacement and renewal		2,319	2,706	4,520	4,230	1,194	3,344	2,181	2,036	1,726	1,726	1,726
36	Asset relocations		6	6	6	6	6	6	6	6	6	6	6
37	Reliability, safety and environment:												
38	Quality of supply		61	95	95	46	41	41	41	41	41	41	41
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		197	155	14	-	-	-	-	14	-	-	-
41	**Total reliability, safety and environment**		258	250	109	46	41	41	41	55	41	41	41
42	**Expenditure on network assets**		6,284	3,278	4,905	4,551	4,013	3,661	3,372	3,241	2,918	2,918	2,918
43	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**		6,284	3,278	4,905	4,551	4,013	3,661	3,372	3,241	2,918	2,918	2,918
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses		-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion		-	-	-	-	-	-	-	-	-	-	-
49	Research and development		-	-	-	-	-	-	-	-	-	-	-
50													

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
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		-	-	6	11	16	22	28	33	39	44	49
55	System growth		-	-	-	-	153	-	90	108	125	143	160
56	Asset replacement and renewal		-	-	95	169	73	278	225	250	247	281	316
57	Asset relocations		-	-	0	0	0	0	1	1	1	1	1
58	Reliability, safety and environment:												
59	Quality of supply		21	-	2	2	3	3	4	5	6	7	8
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		40	-	0	-	-	-	-	2	-	-	-
62	**Total reliability, safety and environment**		61	-	2	2	3	3	4	7	6	7	8
63	**Expenditure on network assets**		61	-	103	182	245	304	347	399	417	476	534
64	Expenditure on non-network assets		-	-	-	-	-	-	-	-	-	-	-
65	**Expenditure on assets**		61	-	103	182	245	304	347	399	417	476	534
66													

Schedule 11a. – Capital Expenditure Forecast (continued)

		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
11a(ii): Consumer Connection								
*Consumer types defined by EDB**			$000 (in constant prices)					
	Customer Connections (≤ 20kVA)		36	62	62	62	62	62
	Customer Connections (21 to 99kVA)		65	49	49	49	49	49
	Customer Connections (≥ 100kVA)		491	111	111	111	111	111
	Distributed Generation Connection		-	2	2	2	2	2
	New Subdivisions		-	46	46	46	46	46
	**include additional rows if needed*							
	Consumer connection expenditure		592	270	270	270	270	270
less	Capital contributions funding consumer connection		178	81	83	84	86	88
	Consumer connection less capital contributions		415	189	187	186	184	182
11a(iii): System Growth								
	Subtransmission		167	-	-	-	-	-
	Zone substations		2,943	47	-	-	2,502	-
	Distribution and LV lines		-	-	-	-	-	-
	Distribution and LV cables		-	-	-	-	-	-
	Distribution substations and transformers		-	-	-	-	-	-
	Distribution switchgear		-	-	-	-	-	-
	Other network assets		-	-	-	-	-	-
	System growth expenditure		3,110	47	-	-	2,502	-
less	Capital contributions funding system growth		-	-	-	-	-	-
	System growth less capital contributions		3,110	47	-	-	2,502	-

		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
11a(iv): Asset Replacement and Renewal			$000 (in constant prices)					
	Subtransmission		-	-	-	-	-	-
	Zone substations		124	4	166	4	121	1,538
	Distribution and LV lines		137	117	98	98	98	98
	Distribution and LV cables		81	81	81	81	81	81
	Distribution substations and transformers		1,379	1,831	3,251	3,123	726	1,460
	Distribution switchgear		137	117	98	98	98	98
	Other network assets		461	556	826	826	69	69
	Asset replacement and renewal expenditure		2,319	2,706	4,520	4,230	1,194	3,344
less	Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
	Asset replacement and renewal less capital contributions		2,319	2,706	4,520	4,230	1,194	3,344

		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
11a(v):Asset Relocations								
*Project or programme**			$000 (in constant prices)					
	Asset Relocation Projects		6	6	6	6	6	6
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	**include additional rows if needed*							
	All other project or programmes - asset relocations		-	-	-	-	-	-
	Asset relocations expenditure		6	6	6	6	6	6
less	Capital contributions funding asset relocations		-	-	-	-	-	-
	Asset relocations less capital contributions		6	6	6	6	6	6

		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
11a(vi):Quality of Supply								
*Project or programme**			$000 (in constant prices)					
	Supply Quality Upgrades - City		-	62	62	12	12	12
	Supply Quality Upgrades - Bluff		-	6	6	6	1	1
	Network Automation Projects		61	28	28	28	28	28
	[Description of material project or programme]							
	[Description of material project or programme]							
	**include additional rows if needed*							
	All other projects or programmes - quality of supply		-	-	-	-	-	-
	Quality of supply expenditure		61	95	95	46	41	41
less	Capital contributions funding quality of supply		-	-	-	-	-	-
	Quality of supply less capital contributions		61	95	95	46	41	41

Schedule 11a. – Capital Expenditure Forecast (continued)

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	[Description of material project or programme]	-	-	-	-	-	-
140	[Description of material project or programme]						
141	[Description of material project or programme]						
142	[Description of material project or programme]						
143	[Description of material project or programme]						
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	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	Earth Upgrades - City	-	-	12	-	-	-
154	Earth Upgrades - Bluff	-	-	1	-	-	-
155	Substation Safety	61	73	-	-	-	-
156	NER Installations	136	82	-	-	-	-
157	[Description of material project or programme]						
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
160	**Other reliability, safety and environment expenditure**	197	155	14	-	-	-
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	197	155	14	-	-	-
163							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
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	[Description of material project or programme]						
170	[Description of material project or programme]						
171	[Description of material project or programme]						
172	[Description of material project or programme]						
173	[Description of material project or programme]						
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	[Description of material project or programme]						
180	[Description of material project or programme]						
181	[Description of material project or programme]						
182	[Description of material project or programme]						
183	[Description of material project or programme]						
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. – Operational Expenditure Forecast

Company Name: **Electricity Invercargill Limited**
AMP Planning Period: **1 April 2016 – 31 March 2026**

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		Current Year 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	482	700	714	728	742	758	772	786	800	814	828
11	Vegetation management	-	1	1	1	2	2	2	2	2	2	2
12	Routine and corrective maintenance and inspection	584	795	841	827	844	861	877	925	909	925	941
13	Asset replacement and renewal	159	104	106	108	110	112	114	117	119	121	123
14	**Network Opex**	1,225	1,600	1,663	1,664	1,698	1,733	1,765	1,829	1,829	1,861	1,893
15	System operations and network support	949	681	711	762	777	794	808	823	837	852	867
16	Business support	2,186	2,419	2,515	2,560	2,612	2,666	2,715	2,764	2,814	2,863	2,912
17	**Non-network opex**	3,135	3,100	3,226	3,322	3,389	3,459	3,523	3,587	3,651	3,715	3,779
18	**Operational expenditure**	4,360	4,700	4,889	4,986	5,087	5,192	5,288	5,416	5,480	5,576	5,672
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	482	700	700	700	700	700	700	700	700	700	700
23	Vegetation management	-	1	1	1	1	1	1	1	1	1	1
24	Routine and corrective maintenance and inspection	584	795	824	795	795	795	795	824	795	795	795
25	Asset replacement and renewal	159	104	104	104	104	104	104	104	104	104	104
26	**Network Opex**	1,225	1,600	1,629	1,600	1,600	1,600	1,600	1,629	1,600	1,600	1,600
27	System operations and network support	949	681	696	733	733	733	733	733	733	733	733
28	Business support	2,186	2,419	2,463	2,462	2,462	2,462	2,462	2,462	2,462	2,462	2,462
29	**Non-network opex**	3,135	3,100	3,159	3,194	3,194	3,194	3,194	3,194	3,194	3,194	3,194
30	**Operational expenditure**	4,360	4,700	4,788	4,794	4,794	4,794	4,794	4,823	4,794	4,794	4,794
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	125	125	125	125	125	125	125	125	125	125	125
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	89	88	88	88	88	88	88	88	88	88	88
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		Current Year 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	-	-	15	28	43	58	72	86	100	114	128
43	Vegetation management	-	-	0	0	0	0	0	0	0	0	0
44	Routine and corrective maintenance and inspection	-	-	17	32	49	66	82	101	114	130	146
45	Asset replacement and renewal	-	-	2	4	6	9	11	13	15	17	19
46	**Network Opex**	-	-	34	64	98	133	165	200	229	261	293
47	System operations and network support	-	-	15	29	45	61	75	90	105	119	134
48	Business support	-	-	52	98	150	204	254	303	352	401	450
49	**Non-network opex**	-	-	66	128	195	265	329	393	457	521	585
50	**Operational expenditure**	-	-	101	192	292	398	494	593	686	781	877

Schedule 12a. – Asset Condition

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2016 – 31 March 2026

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.	-	5.00%	75.00%	20.00%	-	1	5.00%
11	All	Overhead Line	Wood poles	No.	10.00%	70.00%	20.00%	-	-	1	10.00%
12	All	Overhead Line	Other pole types	No.	-	-	100.00%	-	-	1	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	100.00%	-	-	1	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	70.00%	30.00%	-	1	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	100.00%	-	-	1	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	15.00%	15.00%	25.00%	45.00%	-	1	15.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	100.00%	-	-	1	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	50.00%	-	50.00%	-	-	1	50.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	20.00%	80.00%	-	-	1	20.00%
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	25.00%	15.00%	25.00%	35.00%	-	1	25.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35											

					Asset condition at start of planning period (percentage of units by grade)						
36											
37	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
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	30.00%	25.00%	45.00%	-	1	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.00%	23.00%	70.00%	5.00%	-	1	5.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	2.00%	90.00%	8.00%	-	1	10.00%
44	HV	Distribution Cable	Distribution UG PILC	km	2.00%	5.00%	93.00%	-	-	1	15.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	100.00%	-	-	1	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.00%	25.00%	70.00%	-	-	1	25.00%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5.00%	15.00%	70.00%	10.00%	-	1	10.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	4.00%	6.00%	80.00%	10.00%	-	1	10.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.00%	7.00%	75.00%	15.00%	-	1	10.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.00%	9.00%	75.00%	15.00%	-	1	5.00%
53	HV	Distribution Transformer	Voltage regulators	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	10.00%	90.00%	-	-	1	20.00%
55	LV	LV Line	LV OH Conductor	km	5.00%	10.00%	80.00%	5.00%	-	1	5.00%
56	LV	LV Cable	LV UG Cable	km	2.00%	3.00%	90.00%	5.00%	-	1	5.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.00%	4.00%	85.00%	10.00%	-	1	5.00%
58	LV	Connections	OH/UG consumer service connections	No.	1.00%	4.00%	85.00%	10.00%	-	1	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	25.00%	15.00%	25.00%	35.00%	-	1	25.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	20.00%	80.00%	-	-	1	20.00%
61	All	Capacitor Banks	Capacitors including controls	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A
62	All	Load Control	Centralised plant	Lot	-	100.00%	-	-	-	1	100.00%
63	All	Load Control	Relays	No.	-	5.00%	10.00%	5.00%	80.00%	1	100.00%
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Schedule 11b. – Capacity Forecast

Company Name **Electricity Invercargill Limited**
AMP Planning Period **1 April 2016 – 31 March 2026**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Spey Street	32	36	n-1	40	89%	36	95%	No constraint within +5 years	
10	Leven Street	21	23	n-1	25	91%	23	96%	No constraint within +5 years	Short interruption for changeover (N.O. supply from alt GXP)
11	Racecourse Road	11	-	n	12	-	-	N/A	No constraint within +5 years	No firm capacity
12	Southern	11	-	n	12	-	23	49%	No constraint within +5 years	Upgrade to n-1 security in 5yrs time
13						-				
14						-				
15						-				
16						-				
17						-				
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 11c. – Demand Forecast

Company Name **Electricity Invercargill Limited**
AMP Planning Period **1 April 2016 – 31 March 2026**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 **12c(i): Consumer Connections**

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
10		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**							
12	Customer Connections (≤ 20kVA)		22	22	22	22	22	22
13	Customer Connections (21 to 99kVA)		-	1	-	1	-	1
14	Customer Connections (≥ 100kVA)		1	1	1	1	1	1
15	[EDB consumer type]							
16	[EDB consumer type]							
17	**Connections total**		23	24	23	24	23	24
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		5	20	25	30	35	42
21	Capacity of distributed generation installed in year (MVA)		0	0	0	0	0	0

22 **12c(ii) System Demand**

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
24	**Maximum coincident system demand (MW)**		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25		GXP demand		64	65	66	66	67	68
26	*plus*	Distributed generation output at HV and above		-	-	-	-	-	-
27		**Maximum coincident system demand**		64	65	66	66	67	68
28	*less*	Net transfers to (from) other EDBs at HV and above		3	3	3	3	3	3
29		**Demand on system for supply to consumers' connection points**		62	62	63	64	65	65
30	**Electricity volumes carried (GWh)**								
31		Electricity supplied from GXPs		253	254	254	255	256	256
32	*less*	Electricity exports to GXPs		-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation		-	-	-	-	-	-
34	*less*	Net electricity supplied to (from) other EDBs		(19)	(19)	(19)	(19)	(19)	(19)
35		**Electricity entering system for supply to ICPs**		272	273	273	274	275	275
36	*less*	Total energy delivered to ICPs		258	259	259	260	261	261
37		**Losses**		14	14	14	14	14	14
38									
39		**Load factor**		50%	50%	50%	49%	49%	48%
40		**Loss ratio**		5.1%	5.1%	5.1%	5.1%	5.1%	5.1%

Schedule 11d. – Reliability Forecast

Company Name **Electricity Invercargill Limited**
AMP Planning Period **1 April 2016 – 31 March 2026**
Network / Sub-network Name

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
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)		2.0	2.0	2.0	2.0	2.0	2.0
12	Class C (unplanned interruptions on the network)		20.5	19.1	19.1	19.0	19.0	19.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.01	0.01	0.01	0.01	0.01	0.01
15	Class C (unplanned interruptions on the network)		0.56	0.56	0.56	0.56	0.56	0.56

Schedule 13. – Asset Management Maturity Assessment Tool

Company Name	Electricity Invercargill Limited
AMP Planning Period	1 April 2016 – 31 March 2026
Asset Management Standard Applied	Pass 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Question
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's ensured its asset management information system is relevant to its needs?	2	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	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 are 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 non compliance 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 - Directors Approval

We, Neil Douglas Boniface and Thomas Campbell, being directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Electricity Invercargill Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Electricity Invercargill Limited's corporate vision and strategy and are documented in retained records.

N D Boniface

T Campbell

Date: 31-3-2016